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Review of the Draft Supplemental Generic Environmental Impact Statement Concerning Natural Gas Development of the Marcellus Shale within the New York City Watershed

Prepared for the Watershed Inspector General,
Office of the Attorney General for the
State of New York

30 December 2009

ARCADIS

Jerry H Koblitz

Jerry Koblitz
Senior Vice President

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Prepared for:
Watershed Inspector General
Office of the Attorney General
State of New York
The Capitol
Albany, NY 12224-0341

Prepared by:
ARCADIS U.S., Inc.
630 Plaza Drive
Suite 200
Highlands Ranch
Colorado 80129
Tel 720.344.3500
Fax 720.344.3535

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1. Introduction

The Watershed Inspector General, Office of the Attorney General (OAG) for the State of New York has contracted with ARCADIS U.S., Inc. (ARCADIS) to assist with review and comment on the draft Supplemental Generic Environmental Impact Statement (dSGEIS) concerning Natural Gas Development in the New Your City (NYC) Watershed. This document is currently open for the designated public comment period.

The scope of the ARCADIS review includes examination of the technical completeness of the assessment to determine potential environmental impacts associated with development of natural gas resources within the New York City water supply watershed.

This review includes the following sections that discuss ARCADIS' experience and expertise in oil and gas development projects, results of the review of the dSGEIS, and recommendations for further analyses.

2. ARCADIS' Experience and Expertise in Oil and Gas

ARCADIS is an international company providing consultancy, design, engineering, and management services in infrastructure, environment and buildings to enhance mobility, sustainability and quality of life. ARCADIS develops, designs, implements, maintains and operates projects for companies and governments. With more than 15,000 employees, the company has an extensive international network that is supported by strong local presence.

ARCADIS has a long history with our clients pursuing oil, gas, and mining opportunities in the United States and throughout the world. For oil, gas, and mining development, ARCADIS has prepared more than 50 environmental assessments (EAs) and environmental impact statement (EISs) for programmatic and individual project activities. As a result of this experience, ARCADIS can provide insight into development strategies, assessment of potential impacts that may result from development, and implementation of programs and projects with appropriate measures to lessen or eliminate potential impacts.

We have provided a variety of supporting assessments and analysis for issues potentially impacting various stages of development, including environment (e.g., ecology, air, water, and waste), water rights/availability/quality, cultural resources, socioeconomic, permitting and compliance support, sustainable development, and health and safety. The stages of development that have been assessed include exploration, field development, upgrading and processing alternatives, and restoration/ reclamation of facilities and disturbed areas. In addition, assessments have been made of associated infrastructure issues (e.g., well pads, surface transportation, pipelines, water sources and treatment, electrical power, etc).

ARCADIS has provided a multidisciplinary approach that engages a number of specialties, including the following:

- NEPA compliance
- Regulatory compliance and environmental management
- Permitting strategy and approval requirements
- Stakeholder engagement strategies and programs
- Ecological studies
- Ecological risk assessment
- Water resources
- Solid and wastewater engineering and management

- Air quality management
- Cultural resources
- Social and economic studies
- GIS/CADD

3. The Proposed Action

As noted in Chapter 1 of the dSGEIS, the Department of Environmental Conservation (DEC) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus Shale for natural gas production. The wells would undergo a stimulation process known as hydraulic fracturing, which functions to release gas embedded in shale deep below the surface. In addition, potential exists for development of the Utica Shale and other shale and low-permeability formations in New York using the same techniques, if the development of Marcellus Shale using these techniques is successful.

Chapter 2 of the dSGEIS describes the Proposed Action as "...the Department's issuance of permits to drill, deepen, plug back or convert wells for horizontal drilling and high-volume hydraulic fracturing in the Marcellus Shale and other low-permeability natural gas reservoirs." The primary target formations for this evaluation are the Marcellus Shale and Utica Shale. In addition, Chapter 2 notes that the "...SGEIS is focused on topics not addressed by the original GEIS, with emphasis on potential impacts associated with the large volumes of water required to hydraulically fracture horizontal shale wells using the slick water fracturing technique and the disturbance associated with multi-well sites." DEC will use the findings of this evaluation to determine the criteria and conditions for future approvals of permits for drilling and developing wells in these formations. Consequently, the dSGEIS (and GEIS as well) is a programmatic evaluation.

As a programmatic evaluation, we do not expect the dSGEIS to evaluate site-specific issues associated with individual development facilities. A variety of location-specific factors (e.g., soil type, watershed, habitat, vegetation, viewshed, and public sentiment) will vary considerably from site to site and county to county. In addition, the variations in project size and design will greatly determine the magnitude of the impacts from given projects. The combined effects of these location-specific and project-specific factors cannot be fully anticipated or addressed in a programmatic analysis; such effects must be evaluated at the project level. Thus, this dSGEIS should identify the range of potential impacts and relevant mitigation measures. Site-specific and species-specific issues will be addressed during individual project reviews. Individual project analyses, review, and approval may tier off of the dSGEIS but will not be supplanted by it.

4. Results of our Review of the Supplemental Generic Environmental Impact Statement

The description of the Proposed Action within the dSGEIS should be expanded for a more sufficient and effective impact analysis. The Proposed Action includes no scale of development, no rate of development, no potential distribution of wells, no estimate of overall potential disturbance, and only a limited description of ancillary facilities. There is little information on which to conduct an impact analysis, especially an evaluation of potential cumulative effects. For example, developing the Marcellus and Utica shales could be the greatest source of soil disturbance within the overlying watersheds in decades and the dSGEIS currently does not address it at an appropriate scale.

The West of Hudson (WOH) Watershed generally supplies 90 percent of NYC's drinking water. The dSGEIS concludes on page 6–42 that "degradation of New York City's drinking water supply as a result of surface spills is not a reasonably anticipated impact of the proposed activity." However, spills, leaks or breaches from pits, tanks, and impoundments can release contaminants. A reasonably foreseeable development (RFD) scenario can be used to project areas of surface disturbance, such as access roads, well sites, staging areas, pits, and impoundments, which can be affected by flood events where waters cover disturbed areas or erosion where surface runoff crosses disturbed areas. Surface waters can pick up contaminants from disturbed areas, affecting water quality downslope or downstream. Sedimentation of reservoirs or water courses can include the addition of phosphorous-rich soils to surface waters. The effectiveness of natural attenuation processes in soil and water and required setbacks from reservoirs or watercourses will be affected by the number, size, capacity, and location of the facilities anticipated in the RFD scenario, and the mitigating measures applied over the life of the RFD scenario. Further analysis of the effects and risks for the WOH Watershed should be documented in the dSGEIS.

One can readily assemble a scenario that suggests the Proposed Action would far exceed the current level of development and number of active natural gas wells in New York (the "baseline" number of wells), which is about 6,700 (as stated on page 2–4). For example, in Chapter 4, the dSGEIS notes that the Marcellus Shale covers approximately 18,700 square miles in New York (Section 4.4) and the Utica Shale covers approximately 28,500 square miles in New York (Section 4.3). The discussion in Section 5.1.3 suggests that under the scenario of horizontal wells with multiple wells drilled from common pads, 6 to 8 horizontal shale gas wells could access one square mile (640 acres). For example, if even just half of the Marcellus Shale is developed using 6 horizontal wells on a single well pad per square mile, the number of new wells developed would exceed 56,000. If between 5 and 10 percent of these wells are developed in the WOH Watershed, there would be between 2,800 and 5,600 such wells. If one includes the additional wells for the Utica Shale (more than 85,000 with 50 percent development and 6 wells per square mile) and other low-permeability formations, the number of new natural gas wells would far exceed the number of current active natural gas wells.

When one considers the potential number of new wells, pads, miles of access roads, and other ancillary facilities that could be constructed in the various watersheds underlain by the formations, it becomes clear very quickly that the Proposed Action used in the dSGEIS and the discussion of its potential impacts requires further quantitative analysis.

The Proposed Action in the dSGEIS would benefit greatly from the development and use of the RFD scenario mentioned earlier. The use of such a scenario for NEPA analysis represents an accepted best practice in environmental decision making. All programmatic-level NEPA analyses that we have conducted recently have been based on the use of an RFD scenario. For example, we recently evaluated an RFD scenario that included the potential development of 40,000 new coal bed methane wells within an 8,000,000-acre project area over ten years. Input from the companies that had leases in the area and federal management personnel was used to develop all aspects of the scenario. The estimates used in an RFD scenario represent the professional judgments of company representatives, government regulators, and other professionals who are best informed regarding future plans for the area. Some estimates may be based on similar activities already ongoing in other areas.

When used as the foundation of a NEPA or New York State Environmental Quality Review Act (SEQRA) analysis, an RFD scenario provides the opportunity to analyze specific effects associated with the anticipated activities, allowing the description of the magnitude and intensity of the effects, rather than just a list of potential effects. An RFD scenario provides a programmatic projection of the anticipated level of development of the Marcellus Shale that can be effectively used to evaluate direct, indirect, and (especially) cumulative effects by watershed and develop appropriate alternatives to the Proposed Action.

Finally, we recommend that an alternative that eliminates potential natural gas development in the WOH Watershed be evaluated. The purpose of this alternative would be to address concerns about contamination of the water supply for millions of State residents. Use of an RFD scenario would readily facilitate the analysis of such an alternative and a comparison of the effects of this alternative with the Proposed Action.

This would include analysis of the economic effects of eliminating these watersheds from development.

Another alternative that we recommend be evaluated is staged development that delays drilling in the WOH Watershed for a period of time to allow full evaluation of the actual effects of development in other areas of the state. Again, use of an RFD scenario would readily facilitate the analysis of such an alternative and a comparison of the effects of this alternative with the Proposed Action.

4.1 The RFD Scenario

The potential RFD scenario for use in the dSGEIS would include a variety of components and levels of detail. We believe much of the information in the RFD scenario could come from the involved energy companies. Types of information commonly included in RFD scenarios for the development of natural gas are:

- Geographic or areal extent of the anticipated activities associated with the RFD scenario
- Planning horizons for anticipated activities
- Descriptions of anticipated activities (with input from the involved energy companies), including operating requirements of the energy companies and anticipated production rates
- Required management/regulatory constraints, mitigating measures, or performance standards for anticipated activities
- Type and quantity of surface disturbance for categories of anticipated activities, such as drill pads, roads, pipelines, injection wells, and other facilities
- Where possible, highlight key resources affected, such as surface and groundwater used, road surfacing and rock sources used, forested cover removed, water influence zones (wetlands, floodplains, watercourses, riparian and streamside areas) crossed, or sensitive soils disturbed
- Level and nature of human support activities needed for anticipated activities, including traffic changes in communities
- Contaminants (such as drilling or well stimulation additives), noise, emissions, sedimentation, and visual changes associated with anticipated activities
- Waste management and interim and final reclamation planned for anticipated activities

- Where possible, highlight available statistical risks for spills, explosions, human health problems, and traffic accidents associated with anticipated activities

We believe an RFD scenario can be developed with a reasonable level of effort and would return substantial dividends. The DEC should be able to work with companies in actively evaluating drilling in the Marcellus and Utica shales to develop an RFD scenario that could function as a programmatic projection of the anticipated level of development. In our experience, companies are willing to work with agencies in developing such a scenario when their information is kept confidential. Such work promotes both the quality and the expedition of environmental review. The DEC also could use information available from development activities in other locations, particularly in the Marcellus Shale in Pennsylvania, to guide preparation of the RFD scenario.

We have included an example of an RFD scenario for drilling in the Powder River Basin of Wyoming as Attachment 1 to this report.

4.1.1 Potential Components of a Marcellus Shale RFD Scenario

Extrapolating from other RFD scenarios with which we have worked, we have identified some potential components of an RFD scenario for development of gas from the Marcellus Shale in New York:

- Anticipated area of development (ideally should have geological rather than administrative limits);
- A starting point that represents existing development;
- Anticipated well spacing, including whether multi-well pads would be used;
- Estimated number of wells and supporting facilities over a 10 year planning horizon;
- Transportation and pipeline systems needed to support the RFD scenario;
- Intensity of construction and trucking activities associated with the RFD scenario;
- Facilities design factors for an anticipated drilling program and production period, with production rates estimated;
- There should be enough details provided about the well depth, rig size, pad size (incl. surfacing needs), road standards (width, turnouts, maximum gradient, surfacing needs), water supply for drilling and well stimulation, pipeline needs, etc., so that the surface disturbance and surface water/

groundwater impacts for the development anticipated over at least a 10-year planning horizon can be estimated and plotted to evaluate watershed and groundwater impacts. Details should allow some quantification and modeling of impacts;

- We recommend consideration of alternatives to the RFD scenario and other scenarios, such as no action, a prohibition on development in NYC's WOH Watershed, and staged development of the RFD scenario in areas outside the WOH Watershed combined with deferring development in WOH Watershed for years until monitoring results can provide assurance of negligible risk to the municipal water supply. These alternatives would preclude any adverse impacts associated with the RFD scenario in the WOH Watershed.

4.2 Comments on Specific Resource Areas

In addition to our recommendations that an RFD scenario be developed, we also have some comments on specific resource areas in the dSGEIS and how their analyses would be improved with an RFD scenario.

4.2.1 Water Resources

4.2.1.1 Affected Environment of the RFD Scenario

In order to analyze the potential effects of proposed activities on the WOH Watershed, it is necessary to have a good understanding of the proposed activities and the existing conditions for various resources. In order to perform an environmental impact analysis, it is necessary to know the starting point for conditions related to water resources within the WOH Watershed.

This baseline information is essential to any environmental impact analysis, whether programmatic, such as the dSGEIS, or site-specific, such as an analysis to consider a specific well pad. In a programmatic analysis baseline information will be less detailed than in a site-specific analysis. Baseline information presented in the dSGEIS is inadequate to evaluate the potential impacts on water-related resources.

A plan for the collection and compilation of baseline information on surface and groundwater resources should be developed. Baseline information should fully support the analysis. Baseline information should include surface and groundwater characteristics of potential water sources for proposed activities, including a comparison with the characteristics of surface waters used for municipal water supply in the WOH Watershed.

Supporting baseline information also will include data that extends beyond information that is strictly related to water resources. This will include information about the pattern of existing drilling activity in the WOH Watershed and data on existing surface disturbance in that watershed, soil types, erosion rates, forested cover, revegetation/reclamation potential, miles of roads in close proximity to watercourses ... ter developments in close proximity to watercourses and reservoirs, topography, areas not available for development, concerns regarding phosphorous and ... concern, and other relevant data.

... vironment for water resources includes surface water resources and ... ources. The RFD scenario facilitates the opportunity to focus on ... f the environment associated with the activities anticipated in the ...

... ace water resources should be described by watershed, including lengths and descriptions of affected watercourses such as streams and rivers, existing watershed conditio... geomorphic integrity, and sensitive soils. Perennial and intermittent streams, existing water quality and flows, stream channel/bank conditions and stability, natural flow characteristics, existing forested cover, reservoirs and lakes, designated uses, impaired water bodies, wetlands, floodplains, aquatic habitats, and existing water use would be described.

Groundwater resources should be described by water-bearing formation, focusing on groundwater quality, quantity, and use for each aquifer. Contributions to base flows of watercourses would also be described. Water use would identify the number, depth, target formation, beneficial use, flow, and quality of existing permitted water wells and similar information available for identified springs.

4.2.1.2 *Anticipated Impacts on the Affected Environment of the RFD Scenario*

The environmental effects on water resources include surface water resources and groundwater resources. The RFD scenario facilitates the opportunity to analyze the magnitude, intensity, and frequency of direct, indirect, and cumulative effects associated with the activities anticipated in the dSGEIS. It also facilitates writing mitigating measures as performance standards that can be analyzed for effectiveness, feasibility, and cost, and then subsequently monitored or enforced.

The environmental effects on surface and groundwater resources in the WOH Watershed should be described in more detail. The analysis should include the evaluation of the anticipated methodologies for proposed activities, full consideration of the potential effects for the number of wells and other facilities proposed, analysis of risk to Filtration Avoidance and loss of public confidence in NYC's water, and thorough analysis of the effects related to phosphorous, turbidity, and pathogens. Potential discharges of phosphorous, turbidity, and pathogens must be explicitly evaluated because these contaminants are pollutants of concern for the WOH Watershed.

The anticipated direct and indirect environmental effects on surface water resources should be described by watershed, and should focus on stream health, watershed conditions, water quality and designated uses, surface water flows, anticipated surface water withdrawals, stormwater runoff and sedimentation, effect of flood events, and magnitude and intensity of potential effects associated with various water resource-related risks.

The anticipated direct and indirect environmental effects on groundwater resources should be described by water-bearing formation, focusing on groundwater quality, quantity, and consumptive use anticipated for each aquifer based on the RFD scenario. Effects on groundwater quality and quantity should be focused on the magnitude and intensity of potential effects associated with various water resource-related risks of the RFD scenario. Potential effects on contributions to base flows of watercourses and drawdown or other effects on existing permitted water wells should be described and modeled as necessary. Anticipated groundwater withdrawals for drilling and well stimulation should be described for an appropriate area of influence, such as a groundwater basin or other system. Groundwater effects also should be reported by watershed where appropriate.

4.2.1.3 *Cumulative Effects of the RFD Scenario on Watersheds*

The cumulative effects on surface and groundwater resources in the WOH Watershed should be described at greater length in an expanded analysis. An RFD scenario would facilitate the analysis of the water resource impacts by watershed from all past, present, and reasonably foreseeable activities in that watershed. For example, if a new housing development or road improvement project were proposed in the same watershed where Marcellus Shale development is anticipated, the cumulative effects of surface disturbance, cover removal, sedimentation, contaminants, water use, and other water resource impacts could be considered for the watershed, provided information on the other proposed developments is available.

4.2.2 Anticipated Economic Benefits and Risk of the RFD Scenario

Economic benefits of the RFD scenario include the gas produced, the jobs created and sustained directly by the anticipated activities and indirectly by increased services in local communities, and the benefit to local businesses from the value of the goods supplied to RFD scenario activities. The economic benefits of the RFD scenario can be discussed in relation to water resource impacts associated with the RFD scenario, such as surface disturbance and removal of forested cover in watersheds, stormwater and sedimentation, water use, phosphorous in reservoirs, contaminants introduced, and possible spills. The potential economic cost of filtration/treatment of NYC's watershed resources or reduced consumption of WOH Watershed water also can be estimated and compared with economic benefits of the RFD scenario. Estimates of economic benefits of alternatives to the RFD scenario (such as no drilling in the WOH Watershed) can also be assessed to see if these benefits could be realized by drilling in other areas.

Any potential risk to Filtration Avoidance or loss of public confidence in NYC's water can be described based on anticipated potential changes to area watersheds. Any potential risks or losses to other non-priced resources, such as reservoir/lake/stream/river-related tourism, can also be described, based on anticipated potential changes to area watersheds. Use of an RFD scenario would help put potential risks to scale, based on the number of wells and other facilities proposed in the WOH Watershed. The effects on these and other non-priced resources and values should be evaluated by a qualified natural resource economist.

Perspective on another shale gas play that could be useful in evaluating some of the potential economic benefits of Marcellus Shale development can be found in previous studies. These include statistics for the Barnett Shale development in Texas, found at http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf and Barnett Shale impact studies prepared by the Perryman Group (2007, 2009), found at http://www.barnettshaleexpo.com/docs/Barnett_Shale_Impact_Study.pdf and http://www.barnettshaleexpo.com/docs/2009_eco_report.pdf (all accessed on December 4, 2009).

4.2.3 Anticipated Risks of the RFD Scenario

The RFD scenario facilitates the opportunity to analyze specific risks associated with the activities anticipated in the dSGEIS, allowing the description of the magnitude and intensity of the risks, rather than just a list of potential risks. Using an RFD scenario, the possible frequency of incidents can also be inferred using applicable oil and gas statistics from New York and other states, including ongoing shale gas developments.

Much of the need for a more in depth description of the risks to surface and groundwater resources is based on the potentially large number of wells and facilities that could occur on WOH Watershed lands where development is not already prohibited. A thorough analysis, quantified to the extent possible, will put potential risks to scale, based on the number of wells and other facilities proposed in the WOH Watershed.

According to an article in the stargazette.com (2009), an independent researcher compiled 270 spill incidents related to past oil and gas activities in NY reported to DEC. A DEC official reportedly said that less than 300 instances out of more than 300,000 shows oil and gas issues are disproportionately small. However, an incident rate of one per thousand could yield dozens of incidents based on an RFD scenario that envisioned tens of thousands of wells being drilled.

Other incidents have not been reported to DEC. These other incidents have gone unreported because of the absence of systematic monitoring and sampling of surface waters and groundwater.

Incidents may be clustered in time and geographically. A news release from the Pennsylvania Department of Environmental Protection (2009) documents three separate spills in less than one week at the Cabot Oil and Gas Corp.'s Heitsman well in Dimock Township. About 8,000 gallons of a water/liquid gel mixture were lost during the spills, which polluted Stevens Creek and a nearby wetland. The company was subjected to a fine, required to cease hydraulic fracturing, and required to submit an updated preparedness, prevention and contingency plan and an engineering study. Activities have now been allowed to resume by the state.

Water resource related risks for the WOH Watershed that should be better described and analyzed in the dSGEIS include the following.

4.2.3.1 Loss of Integrity in Well Casings

Fluids can escape into surrounding underground formations, including aquifers or surface waters, if cracks or blowouts occur in well casing due to uncontrolled down-hole pressure during drilling, completion, or production activities. The integrity of a well can be vulnerable during the installation of surface casing, especially if shallow gas migration is an issue in the area. Under certain conditions, gas can migrate along fractures in bedrock and through permeable soils and groundwater aquifers.

An incident in Wyoming involving a blowout (sudden breakage) in the surface casing of Windsor Energy's Crosby 25-3 well contaminated shallow groundwater. This incident is recounted by the Wyoming Outdoor Council (2009) at <http://

wyomingoutdoorcouncil.org/html/what_we_do/public_lands/shoshone.shtml> as accessed on December 2, 2009. A well blowout in August 2006 along Line Creek in Clark, Wyoming contaminated groundwater aquifers and caused an emergency evacuation of the town of Clark. Windsor Energy has undertaken a voluntary remediation program with the Wyoming Department of Environmental Quality, but many local residents are not satisfied with the adequacy of these efforts and still fear for the safety of their drinking water.

In addition, the dSGEIS discusses the possible use of drilling rigs of varying sizes for the drilling of wells. The relative effectiveness of setting casing, controlling down-hole pressure, and the relative risk of a blowout causing surface or groundwater contamination, should be analyzed for each type of drilling rig that could be used.

4.2.3.2 Loss of Circulation in Uncased Portions of Wells

Drilling fluids can be lost into surrounding underground formations, including aquifers, if cracks, joints, or cavities in the uncased portion of the hole are encountered during drilling. Groundwater could be contaminated during this loss of circulation.

4.2.3.3 Reduced Surface Water Flows due to Water Use

The withdrawal of surface water from watercourses, reservoirs, or springs that contribute to base flow for use in drilling or well stimulation (hydraulic fracturing) could cause a reduction in surface flows if excessive withdrawals or withdrawals during low flows are made. Analysis of an RFD scenario by watershed, considering a likely development scenario (including water needs for drilling and well stimulation, estimated number and length of horizontal wells), would provide for improved analysis of the effects on surface flows from water withdrawals.

4.2.3.4 Contamination of Surface Waters by Breaches or Leaks in Pits, Tanks, or Impoundments Containing Source Water, Drilling Fluids, Well Stimulation (Hydraulic Fracturing) Fluids, or Produced Fluids

Risks of a variety of potential sources of surface water contamination, such as reserve pits containing drilling fluids and cuttings used during drilling, flow back tanks containing fluids used in hydraulic fracturing that are returned to the surface after use, mixing tanks for hydraulic fracturing fluids, onsite chemical storage tanks, production tanks containing produced fluids (brines) and possibly concentrations of naturally occurring radioactive material (NORM), and large impoundments that hold source water for drilling should be analyzed by watershed or basin, based on an RFD scenario. Analysis of risk using this scenario will allow a better projection of the magnitude, intensity and frequency of the risks involved.

Source water contained in impoundments prior to use may have different characteristics than municipal supply water. Any leakage or release of source water could introduce constituents that would alter the quality of the municipal water supply.

4.2.3.5 Contamination of Surface Waters by Spill Events Involving Truck Accidents

The risk of truck accidents involving the spills of non-potable water used for drilling or hydraulic fracturing, drilling fluids removed from reserve pits, hydraulic fracturing fluids, production fluids, or chemicals being transported to or from the well pad should be analyzed by watershed or basin, based on an RFD scenario. Analysis of risk based on an RFD scenario and applicable statistics from NY and other areas will allow a better projection of the magnitude, intensity, and frequency of the risks involved.

4.2.3.6 Contamination of Surface Waters by Stormwater Runoff and Sedimentation or Flood Events Affecting Well Sites, Pits, or Impoundments; Well Field Roads; or Other Facilities

Areas of surface disturbance, such as access roads, well sites, staging areas, pits, and impoundments can be affected by erosion where surface runoff crosses disturbed areas. Stormwater runoff crossing disturbed areas can pick up contaminants from disturbed areas (including phosphorous-rich soils), adversely impacting water quality downslope or downstream of the disturbed areas. Increases in turbidity and sedimentation of reservoirs or water courses that are downslope of the disturbed areas can be caused by the erosion of disturbed areas.

Areas of surface disturbance can also be affected by flood events where surface flows erode and scour disturbed areas and pits and impoundments are breached or slope failures occur, likely releasing contaminants to flood waters and affecting water quality downslope or downstream of the disturbed areas. Sedimentation of reservoirs or water courses that are downslope of the disturbed areas can also be caused by flood waters covering disturbed areas. Sedimentation can include the addition of phosphorous-rich soils to surface waters along with other contaminants.

The risk of reduced surface water quality and sedimentation caused by stormwater runoff crossing areas of surface disturbance or flood events should be analyzed by watershed or basin, based on an RFD scenario. Analysis of risk based on this scenario will allow a better projection of the magnitude, intensity, and frequency of the risks involved.

4.2.3.7 Contamination of Surface Water and Groundwater by Naturally Occurring Radioactive Material (NORM)

NORM can be brought to the surface in drill cuttings, flowback, or produced water, and can reach the surface along with the shale gas. Over time, NORM can become concentrated in sludge and sediment inside production tanks.

The risk of surface water and groundwater contamination by leakage of NORM that could be concentrated in flowback tanks or production tanks containing flowback and produced fluids (brines), respectively, should be analyzed by watershed or basin, based on an RFD scenario. Analysis of risk based on this scenario will allow a better description of the magnitude, intensity, and frequency of the risks involved.

4.2.3.8 Contamination of Surface Water and Groundwater by Gas and Fluid Migration Caused by Drilling, Well Stimulation Processes, or Injection of Wastewater

Under certain conditions, gas and fluids can migrate along fractures in bedrock and through permeable soils and groundwater aquifers. Naturally occurring joints or cracks in underground formations or joints or cracks induced by drilling, well stimulation processes, or injection of wastewater could serve as pathways for the movement of gas, fluids, or contaminants into near surface formations, where they could mix with groundwater and enter existing water wells or springs, reach water transport tunnels for the WOH Watershed, or mix with surface waters in reservoirs or watercourses. The gas can build up in nearby water wells or tunnels to levels where an explosion could occur. Analysis of risk based on an RFD scenario and applicable statistics from New York and other areas will allow a better projection of the magnitude, intensity, and frequency of the risks involved.

4.2.3.9 Contamination of Groundwater by Breaches or Leaks in Pits, Tanks, Wells or Impoundments Containing Source Water, Drilling Fluids, Well Stimulation Fluids, or Produced Fluids

Drilling, completion, or production fluids can escape into underground formations, including aquifers, if cracks or joints occur in underground formations. Analysis of risk based on an RFD scenario and applicable statistics from NY and other areas will allow a better projection of the magnitude, intensity, and frequency of the risks involved.

4.2.3.10 Drawdown of Groundwater Aquifers from Water Use

The withdrawal of groundwater from underground aquifers for use in drilling or well stimulation (hydraulic fracturing) could cause a reduction in groundwater availability if excessive withdrawals are made. Existing water wells completed in affected aquifers could experience drawdown of the water level. Analysis of an RFD scenario by groundwater basin or system, considering a likely development scenario (including water needs for drilling, number, location, and depth of wells to be drilled for source water and well stimulation, estimated number and depth of vertical gas wells, estimated number and length of horizontal gas wells), would provide for improved analysis (and modeling where necessary) of the projected effects on groundwater from water withdrawals.

4.2.3.11 *Potential Need for Filtration/Treatment of NYC's West of Hudson (WOH) Watershed Resources (conflict with the filtration avoidance determination) Due to Water Resource Impacts*

Surface water impacts should be analyzed for the WOH Watershed based on an RFD scenario. Analysis based on an RFD scenario will allow a better projection of the magnitude, intensity, and frequency of the risks and effects involved, rather than just a quantitative list of potential risks and effects.

There is an apparent contradiction between pages 2–22 and 7–63 of the dSGEIS, where more than 1,000 square miles of the WOH Watershed appear to be available for development under an RFD scenario, but "review of the existing authorities relative to both water resources in general and the New York City Watershed in particular indicates that the City's water supply is adequately protected..."

As discussed in Section 4 above, the dSGEIS concluded that "degradation of New York City's drinking water supply as a result of surface spills is not a reasonably anticipated impact of the proposed activity." In doing so, however, it did not take into account the potential for breaches, discharges, spills, or leaks of pollutants regulated by the Filtration Avoidance Determination and the Safe Drinking Water Act, including turbidity and pathogens. Nor did it evaluate the effectiveness of proposed mitigation measures in light of the number, size, capacity, and location of drilling related facilities that could be anticipated in an RFD scenario. Further analysis of the effects and risks for the WOH Watershed relating to Filtration Avoidance should be conducted.

4.2.3.12 *Effects on Aquatic Habitats Associated with RFD Scenario*

The risk of changes in surface flows, surface water quality and sedimentation caused by water resource-related risks should be analyzed by watershed or basin, reservoir, watercourse, or other appropriate ecosystem, based on an RFD scenario and mitigating measures applied. Analysis of risk based on an RFD scenario will allow a better projection of the magnitude, intensity, and likelihood of the risks involved. Examples of risks that could be evaluated include releases of sediment from well pads and roads into streams that currently support fisheries and increases of turbidity in streams and reservoirs that service as municipal water supplies. A breach of an impoundment could release water of differing temperature and pH into surface waters. These types of releases could have a detrimental effect on macroinvertebrates and fisheries, especially cold water fisheries such as trout fisheries.

4.2.3.13 Release of Oil and Gas Operations Wastewater Treated at Existing Wastewater Treatment Facilities into Surface Waters

Wastewater from oil and gas operations treated at existing wastewater treatment facilities is likely to have greater salts and dissolved solids than existing surface flows, as acknowledged by the dSGEIS on page 6–39: "Treatability of flowback water is a further concern. Residual fracturing chemicals and naturally occurring constituents from the rock formation could be present in flowback water and have treatment, sludge disposal, and receiving-water impacts. Salts and dissolved solids may not be sufficiently treated by municipal biological treatment and/or other treatment technologies which are not designed to remove pollutants of this nature."

4.3 Mitigating Measures

A mitigating measure is an operating requirement for a proposed activity used to reduce, eliminate, or avoid specific environmental effects that could occur without the measure. Feasibility, cost (as it effects the economics of the proposed activity), and effectiveness in reducing, eliminating, or avoiding impacts should be analyzed for mitigating measures. It will be possible to analyze a mitigating measure if it is written specifically enough, with details on how the activity would be performed.

For the most part, mitigating measures described in the dSGEIS do not contain details or contain only isolated details on how the proposed activity would be performed using the mitigating measure. Mitigating measures typically are written as performance standards that could be analyzed, and subsequently monitored or enforced, but they generally are not in the dSGEIS.

An RFD scenario is essential for the quantitative assessment of the effectiveness of mitigating measures in reducing risks. A thorough analysis, quantified to the extent possible and based on an RFD scenario, will put potential effectiveness of mitigating measures to scale, based on the number of wells and other facilities proposed in the WOH Watershed.

Pages 7–63 and 7–64 describe mitigating measures that would be applied in the WOH Watershed. Setbacks and procedures proposed in this Supplement, along with supplementary permit conditions for high-volume hydraulic fracturing will provide protection to surface water and ground water statewide. Proposed enhanced procedures and requirements specifically applicable to the New York City Watershed include:

- "Prohibition against centralized flowback water surface impoundments within the boundaries of the New York City Watershed (Section 7.1.7),
- Requirement in an unfiltered watershed to remove fluids from any reserve pit or on-site (i.e., well pad) tanks within seven days of completing drilling and stimulation operations at the last well on the pad, or immediately if operations are suspended and the site will be left unattended (Section 7.1.3.2) , and
- Site-specific SEQRA determination for any proposed well pad within 300 feet of a reservoir, reservoir stem or controlled lake or within 150 feet of a watercourse (Section 7.1.12.2).
- To the extent practical, operators should place any blending unit with a mixing hopper used for fracturing operations at least 500 feet from reservoir, reservoir stem or controlled lake and 100 feet from a watercourse or state-regulated wetland in the New York City Watershed, in consideration of Section 18-32(b) of NYC's Watershed Rules and Regulations relative to process tanks."

The above mitigating measures that would be applied within the WOH Watershed represent a good starting point for the protection of NYC's municipal water supply, but are not comprehensive.

The effectiveness of setbacks from reservoirs and watercourses or other siting constraints (and the risk of locating pits, tanks, impoundments or other facilities near reservoirs or watercourses) will be affected by the size, capacity, and location of the facilities, and the mitigating measures applied to them.

Potential water resource-related mitigating measures that should be considered include use of a closed loop system for drilling, extensive requirements for secondary means of containment for fluids, a prohibition on land disposal or burial of cuttings unless advanced technology or a specific study indicates it is the preferred methodology, a network of surface water monitoring stations, a network of groundwater monitor wells, monitoring of nearby water wells, rigorous monitoring of stormwater pollution prevention measures, reclamation monitoring of disturbed areas, control of road alignments/standards and traffic to minimize accidents, and rigorous control and monitoring of construction activities to minimize erosion and sedimentation, and preventing drilling in locations of greater concern (e.g., near surface waters, on steep slopes, etc.).

Attachment 1

Example of an RFD Scenario
Chapter 2 of the 2003 Final Environmental Impact Statement and Proposed Plan Amendment for the Powder River Basin Oil and Gas Project

Chapter 2 — Public Participation, Issue Identification, and Alternatives

This chapter covers five primary topics. First, it describes the process used to obtain the public's concerns and identifies the issues raised by the public. Then, it describes the process used to develop the alternatives considered in this analysis. Third, it describes the project alternatives that were analyzed in detail. The specific features of these alternatives are fully described. Fourth, it identifies each alternative eliminated from detailed consideration and briefly describes the rationale for the exclusion. Finally, it presents, in summary and comparative form, the components and environmental effects of the alternatives analyzed in detail and it identifies the agencies' preferred alternative.

Public Participation

Scoping

BLM and FS consider public participation a crucial component in defining the scope of the environmental analysis presented in this EIS. Consequently, the agencies worked to ensure the public was informed about the Companies' proposal and the opportunities available for participating in the environmental process.

BLM and FS first informed the public of their intent to conduct an environmental impact analysis of oil and gas development in the PRB during May and June 2000. In May, the agencies prepared and mailed 900 copies of a Scoping Letter that solicited comments to assist the BLM and FS in identifying the specific issues and concerns the agencies should address in the analysis and should document in the EIS.

On 21 June 2000, formal scoping for the analysis began with publication in the *Federal Register* of a Notice of Intent (NOI) to prepare an EIS. BLM published additional notices in the *Federal Register* to correct mistakes in the first NOI and to invite the public's participation in the analysis and potential amendments to the RMPs for Buffalo and Platte River.

BLM also sent a news release to more than 60 media outlets (newspapers, radio stations, and television stations) in Wyoming and Montana. This news release announced the intent of the agencies to prepare an EIS and identified times and locations for the public meetings. Additionally, several newspapers prepared stories on the project.

In addition to the publications and mailings, the agencies held four public meetings to discuss the proposal and receive comments from the public. The first meeting was held in Sheridan, Wyoming, on 6 June 2000. The second and third meetings were held on 7 June 2000 in Buffalo, Wyoming, and on 8 June 2000 in Gillette, Wyoming. The final meeting was held in Douglas, Wyoming, on 12 June 2000. The proposal was described and participants were provided the opportunity to ask questions and submit comments at all meetings.

Finally, BLM and FS have been keeping the public informed of the status of the analysis through a periodic newsletter and a project-specific web site (www.prb-eis.org). BLM also included project information on its Wyoming web site.

Review of the DEIS

In mid-January 2002, the DEIS was distributed to the public. The distribution list included the agencies, companies, organizations, and individuals that had expressed an interest in the project during scoping. It also included several agencies and elected officials to whom BLM and the FS commonly send EISs.

The DEIS was available for public review and comment from 18 January 2002, through 15 May 2002. The BLM and FS encouraged reviewers to submit written comments on the document during this period. In addition, the BLM held public meetings on the draft EIS on 18 through 21 March 2002, to provide the public with the opportunity to submit verbal and written comments in person.

Reviewers of the DEIS submitted a variety of comments. Most of the comments were contained in 17,940 letters. However, 28 individuals provided verbal comments at the public meetings. Overall, the comments focused on the issues identified in the DEIS and the NEPA process. Appendix S contains a summary of the comments received on the DEIS and the BLM and FS' responses to those comments.

In response to the comments, BLM and FS made a variety of changes throughout the document. The discussion of the alternatives in Chapter 2 was revised to address errors in some calculations, update information in response to WDEQ's changes in its procedures for permitting disposal of water produced from CBM wells, and to expand and clarify information on the alternatives. For example, a graph showing the cumulative number of CBM wells producing by year was added and WDEQ revised the distributions of methods for handling water produced from CBM wells. Certain assumptions changed to reflect conditions more accurately. The cumulative analysis for air and surface water was coordinated with BLM Montana and cooperators and was combined for this EIS and the Statewide Montana EIS. Discussion of the affected environment in Chapter 3 was expanded to provide at least some of the additional information requested in the comments, particularly the description of biological resources. Throughout Chapter 4, the discussion of environmental consequences was revised and expanded to provide a clearer perception of the likely effects of the alternatives. Because of the variety of changes made throughout the document in response to comments, BLM and FS printed this EIS in its entirety rather than printing it as an abbreviated FEIS.

Issue Identification and Issue Statements

BLM and FS reviewed and analyzed the comments they received during the scoping process. Public response to the notices and meetings included 74 letters, comment forms, and e-mails. In addition, 106 people attended one or more of the four public meetings.

The agencies' process for identifying issues involved three overall steps. First, specific comments were arranged into groups of common concerns. Next, a primary issue statement was prepared for each group of comments. Finally, the issue statements were evaluated for applicability to this NEPA analysis.

The analysis of comments initially identified 27 issues. Eighteen of these 27 issues were identified as key or significant (see November 2000 Scoping Summary to review nonsignificant issues). These issues were used to define the scope of this NEPA analysis. These key issues were used to analyze environmental effects, prescribe mitigation measures, or both. Issues are "significant or key" based on the extent of their geographic distribution, the duration of their effects, or the intensity of interest or resource conflict. The decision on an issue's significance is different than and separate from any determination of the significance of an environmental consequence. The other nine issues were not identified as key because they involved standard parts of a NEPA analysis (for example, the analysis must consider an adequate range of alternatives) or the agencies concluded that they were beyond the scope of this NEPA analysis. The 18 key issues that constituted the overall scope of the NEPA analysis are:

Issue 1: The effects of the additional development of oil and gas resources on aquifers present in and downgradient of the Project Area.

Respondents expressed concerns about the effects on local aquifers when coal beds were depressurized through pumping water. Landowners identified concerns that the pumping could cause them to lose the use of existing water wells, which are sources of water for both humans and livestock. Concerns include direct losses (loss of water wells drilled into coal aquifers) and indirect losses (loss of water wells drilled into aquifers located above, but connected with, the coal beds). Some respondents also were concerned that pumping water from the coal seams could increase the potential for subsidence, which could adversely affect aquifers. Because the availability of uninterruptible supplies of groundwater is important to the economic well-being of landowners in the Project Area, respondents requested groundwater modeling specifically to address the rates of pumping, horizontal and vertical movement of groundwater, recharge of aquifers, interdependence of aquifers, permeability of overburden and layers between the coal seams, and the cumulative effects of depletions caused by withdrawal of oil and gas and depletions that result from coal mining.

Issue 2: The effects of the additional development of oil and gas resources on the quantity and distribution of surface water in and downstream of the Project Area.

Many respondents expressed concerns about the volumes of surface water the Companies would discharge from CBM wells into drainages across the Project Area. Considering the potential number of wells and the rates projected for discharge of produced water from each well, discharges could be too large for some channels to handle, which would allow sheet flows across the land rather than constraining the discharge to the channels of streams. These volumes could overwhelm the abilities of both the Companies and landowners to contain or control the flow of water across properties, which would affect the landowners' uses of the properties. Some respondents indicated that this problem already is evident on some properties where channels have been replaced with spreader dikes. The additional volume of water may also affect the operation of reservoirs in and downstream of the Project Area. Consequently, respondents thought the analysis should estimate and disclose the volumes of produced water expected by watershed. (They also indicated that a single "type curve" for production throughout the Project Area should not be used.) Additionally, they suggested development of detailed watershed plans specifically to address these concerns.

Issue 3: The effects of the additional development of oil and gas resources on the quality of surface water in and downstream of the Project Area and the potential to adversely affect current uses of those surface waters.

Many respondents expressed concerns about the quality of produced water the Companies would discharge into surface drainages and how produced water would affect the existing quality of surface water and other resources that depend on the water. They cited incidental observations to suggest that produced water may impair surface waters by introducing metals (such as iron, manganese, and barium), thereby increasing the sodium adsorption ratio (SAR) and sedimentation; kill vegetation (for example, sagebrush and grass) that it contacts; adversely affect lands and crops irrigated with it; adversely affect sources of municipal water; and adversely affect wildlife and livestock. Produced water also may alter the temperature of streams that receive the discharges. Concerns were greatest for rivers classified as impaired (the Tongue, Powder, and Belle Fourche rivers in Montana and South Dakota). Finally, respondents identified a need for long-term monitoring of the quality of produced water discharged to surface waters.

Issue 4: The effects of the additional development of oil and gas resources on the Project Area's geology, geologic hazards, and the extraction of other mineral resources present in the Project Area.

Respondents expressed concerns about the effects of the additional development of oil and gas resources on extraction of other minerals in the Project Area, particularly coal. Some questioned how the extent of development considered in the alternatives could impair the ability of the mining companies to mine coal. In addition, they questioned whether extraction of groundwater from the coal seams could increase the potential for subsidence and hinder the ability to mine coal or other minerals or whether any re-injection of produced water could increase the potential for earthquakes. Areas prone to landslides also should be considered. Respondents thought the inclusion of a detailed map of the Project Area's geology would help readers understand the situation more completely.

Issue 5: The effects of the additional development of oil and gas resources on soils in and downstream of the Project Area.

Respondents expressed concerns that the project could increase loss of topsoil through erosion (via both water and wind), particularly where the Companies would discharge the produced water. Other concerns include the project's potential to increase compaction of soils and adversely affect the structure and fertility of local soils.

Issue 6: The effects of the additional development of oil and gas resources on air quality and visibility.

Respondents expressed concerns about the effects of additional oil and gas development on the visibility and quality of air in the Project Area. Construction of new roads and facilities and heavier traffic would result in increases in emissions of particulates. Construction of new gas-fired compressors and increases in the volume of traffic would result in additional gaseous emissions. These increases could impair the quality of air and visibility, which may affect the health of humans, wildlife, and livestock (for example, by causing dust pneumonia). Concern also was expressed about long-term venting of methane and its potential effects to air quality. Respondents were concerned about the effects of the alternatives on visibility at Class I areas within the effective airshed of the Project Area.

Issue 7: The effects of the additional development of oil and gas resources on vegetation in and downstream of the Project Area, including wetlands and riparian areas.

Respondents expressed concerns that additional development of oil and gas resources would adversely affect vegetation in the Project Area generally and wetlands and riparian areas specifically. Construction of facilities would directly disturb vegetation over both the short term and long term. Changes in the volume and rate of surface water flows could alter the distribution of vegetative cover types. Wetlands and riparian areas would be most susceptible to changes in the quantity and quality of surface waters. Areas with intermittent flows may experience perennial flows as development expands. In addition, disturbances in the Project Area could increase the potential for the spread of noxious plants at the expense of native vegetation.

Issue 8: The effects of the additional development of oil and gas resources on species of wildlife and their habitats (in particular, key species and habitats).

Respondents expressed concerns that additional oil and gas development would directly, indirectly, and cumulatively affect wildlife and their habitats. Specific concerns were identified for species or groups of species that include raptors, sage grouse, sharp-tailed grouse, deer, elk, antelope, and waterbirds. The effects that concerned most respondents include the direct loss of habitats (particularly crucial winter ranges for large deer, elk, and antelope), disturbance of animals by humans (including additional noise), fragmentation of habitats (primarily through construction of roads, well pads, and fences), introduction of new perches for raptors, increases in hunting pressure, intensified harassment, and project-induced increases in mortality (for example, through poaching, trapping, poisoning, and roadkills).

Issue 9: The effects of the additional development of oil and gas resources on fisheries and aquatic habitats.

Respondents expressed concerns about the potential direct, indirect, and cumulative effects of additional oil and gas development on fisheries and the aquatic habitats on which they depend. The discharge of produced waters could affect fisheries and aquatic habitats by altering the quantity, quality, and temperature of waters in steams and rivers. These concerns were greatest for streams and rivers that contain special-concern species of fish and rivers classified as impaired (the Tongue, Powder, and Belle Fourche rivers in Montana and South Dakota).

Issue 10: The effects of the additional development of oil and gas resources on the Project Area's ecological integrity and biological diversity.

Respondents expressed concerns that additional oil and gas development could adversely affect the natural ecological integrity in and downstream of the Project Area. The additional oil and gas development could alter the biological diversity in the Project Area by changing the composition and abundance of species and the distribution of plants and animals. These changes are important because different species of wildlife require different levels of habitat diversity. Areas specifically identified as of importance to the conservation of biological diversity in the region include the Little Powder River (river banks and adjacent upland sites), Powder River, and Upper Antelope Creek (including the rolling uplands).

Issue 11: The effects of the additional development of oil and gas resources on special-concern species, particularly threatened, endangered, candidate, or sensitive species of plants and animals.

Respondents expressed concerns that additional oil and gas development could adversely affect special-concern species, including species of plants and animals listed as threatened or endangered, proposed for or identified as candidates for listing as threatened or endangered, or identified as sensitive by BLM or the Regional Forester. Species of particular concern to respondents included the black-footed ferret, bald eagle, mountain plover, Ute ladies'-tresses orchid, black-tailed prairie dog, swift fox, sturgeon chub, pallid sturgeon, shovelnose sturgeon, and western silvery minnow. Some respondents noted the need for the analysis to comply with Section 7 of the Endangered Species Act (ESA).

Issue 12: The effects of the additional development of oil and gas resources on rangeland resources and grazing operations.

Respondents expressed concerns about the effects of additional development of oil and gas resources on rangeland resources and grazing operations. The potential loss of water wells for livestock, changes in grazing patterns caused by long-term flooding of hayfields and winter ranges, and the consumption of lower-quality produced water by livestock were the primary concerns. Additional concerns included fencing, harassment of livestock, and the potential for project-induced health problems (for example, dust pneumonia and undernourishment).

Issue 13: The effects of the additional development of oil and gas resources on cultural resources, paleontological resources, and Native Americans.

Respondents expressed concerns about the potential for additional development of oil and gas resources to adversely affect cultural resources, paleontological resources, and Native Americans. In addition to the direct and indirect disturbances associated with construction of facilities, the discharge of produced waters could increase streamflows sufficiently to disturb cultural resources present in steambeds. In addition, the Northern Cheyenne Indian Reservation, which is in the Upper Tongue River watershed immediately downstream of the Project Area, might experience adverse effects from the project.

Issue 14: The effects of the additional development of oil and gas resources on recreational opportunities and the recreational experience.

Respondents expressed concerns about the degree the additional development of oil and gas resources would alter the existing recreational setting and experience. Associated activities would add new sources of noise that could diminish the recreational experience. New roads would provide access for vehicles and promote an increase in human activity. In addition, implementation of the additional development could adversely affect wildlife-related recreation (such as viewing wildlife, hunting wildlife, and fishing). However, development of certain facilities, such as reservoirs to impound produced water, could enhance some wildlife-related recreational opportunities by providing areas for viewing wildlife, hunting waterfowl, or public fishing.

Issue 15: The effects of the additional development of oil and gas resources on the Project Area's aesthetics.

Respondents expressed concerns about the effects of additional development of oil and gas resources on aesthetics in the Project Area. Noise would increase with the addition of compressors, pumps, and traffic. Human activity would become much more visible with the addition of many miles of roads, pipelines, power lines, and fences. These additional features would affect the area's visual quality and cause conflicts with the BLM and FS' visual management systems, which could affect the agencies' management of federal lands in the Project Area.

Issue 16: The effects of the additional development of oil and gas resources on the local economy.

Respondents expressed concerns about the effects of additional development of oil and gas resources on the local economy. Some felt additional development would cause more damage to the local economy over the long term than could be offset by any monetary gain obtained from the leases, royalties, taxes, and jobs. Of particular concern is the discharge of large amounts of groundwater onto the ground. Groundwater is considered vital to the economic well being of the rural communities and respondents believed that it should be afforded some economic value in the analysis. Also of concern were the effects on the availability of affordable housing, an adequate community infrastructure to support an influx of people (for example, law enforcement, medical facilities, schools, and the transportation network), and property values. Some respondents identified concerns about the potential for the project to affect employment and opportunities for employment in Montana by attracting workers away from agriculture and other traditionally lower-paying occupations.

Issue 17: The effects of the additional development of oil and gas resources on human health and safety.

Several respondents expressed concerns about potential dangers or threats to human health and safety with the additional development of oil and gas resources. These concerns included the potentials for and the effects of methane that could migrate into residences and water wells and seep out at outcrops (killing vegetation and wildlife), spontaneous combustion of depressurized coals that could ignite uncontrollable underground fires, contamination of drinking water aquifers by the chemicals used in hydraulic fracturing, ruptures of pipelines, spills, illegal dumping, and the application of treatments (magnesium chloride) to roads.

Issue 18: The analysis needs to include an analysis of environmental justice.

Concerns were expressed about the potential for additional development of oil and gas resources to affect Native American Tribes in Montana. Of particular concern were the Northern Cheyenne and Crow. At a minimum, an analysis of environmental justice should be completed for these tribes.

Process Used to Develop Alternatives

The process of developing alternatives to the Proposed Action involved four steps. First, the agencies conducted project scoping to identify the key issues of concern, which would define the scope of the impact assessment (the 18 issues described above). This scoping involved concerns that were both internal to the agencies and that were raised by the public. It also considered environmental and project-design elements.

The second step consisted of formulating alternatives to the proposal. Each alternative had to meet the purpose of and need for the project. Typically, driving issues (issues used to "drive" the development of alternatives) are identified that help the agencies define the changes that are needed to avoid, eliminate, reduce, minimize, or mitigate effects that would result from implementing the Proposed Action. The agencies identified three issues (Numbers 2, 3, and 6, which involved the quality, quantity, and distribution of surface water, and air quality) as the potential driving issues for this EIS.

The third step involved screening the potential alternatives for reasonableness. The NEPA process requires that alternatives evaluated in detail be reasonable. The regulations for implementing NEPA discuss the need for reasonable alternatives in the NEPA process (40 CFR 1500.1(e) and 1502.14). In addition, CEQ's *40 Most Asked Questions about NEPA* (Question 2a) state, in part, that "reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense" (CEQ 1981).

Based on this direction, the agencies focused the screening of alternatives on technical, environmental, and economic feasibility. Technical considerations included the feasibility of constructing and operating the facilities. Environmental considerations included the potential for significant effects and the feasibility of successfully mitigating them. Economic considerations included potential costs and benefits of implementing the alternative.

Finally, unreasonable alternatives were eliminated from detailed consideration. If an alternative did not pass the technical, environmental, and economic screening for feasibility, it was not considered further in the analysis. BLM has revised the discussion in the section on the Process Used to Develop Alternatives to more clearly define the concepts of key issues and driving issues.

Alternatives Considered in the NEPA Analysis

The process described above resulted in the development of several alternatives that specifically responded to one or more key issues. Although a variety of alternatives was developed, not all were analyzed in detail. Some were deemed unreasonable during the feasibility screening. Others were eliminated after initial analysis indicated they were not reasonable or that conditions had changed, for example when Montana and Wyoming (Appendix B) signed the Interim Memorandum of Cooperation (MOC) to document their commitments and intent to protect and maintain water quality conditions in the PRB within Montana.

The alternatives developed for this NEPA analysis are described in two overall sections. The alternatives analyzed in detail are described first. A section on Alternatives Considered but Eliminated follows the alternatives analyzed in detail (beginning on page 2–65).

Alternatives Analyzed in Detail

Three alternatives were analyzed in detail. They include the Proposed Action (Alternative 1) and No Action Alternative (Alternative 3). Alternatives 2A and 2B are the Proposed Action with Reduced Emission Levels and Expanded Disposed Water Handling Scenarios. The Proposed Action is described first. The descriptions of Alternatives 2 and 3 follow and focus on how they differ from the Proposed Action.

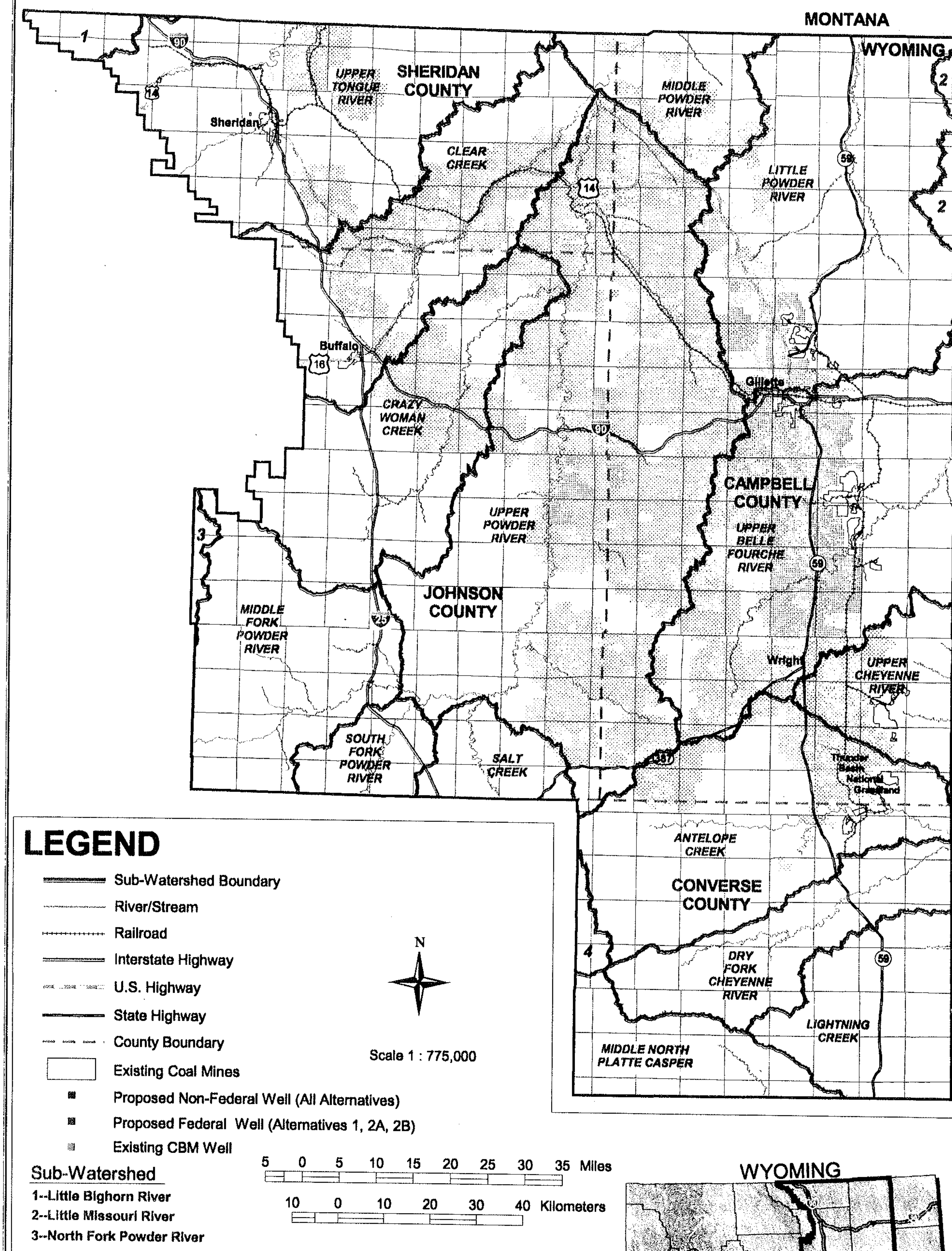
In addition to the details presented below, the action alternatives (Alternatives 1, 2A, and 2B) include the Standard Conditions of Approval (COAs) for APDs that BLM requires for oil and gas wells drilled into federal minerals in the Project Area. These COAs are included as Appendix C.

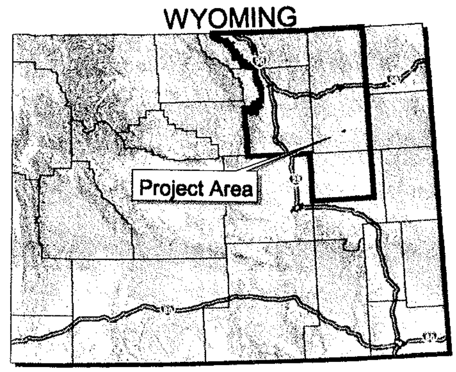
Alternative 1 — Proposed Action

The Proposed Action is to continue development of CBM and conventional oil and gas resources in the Project Area. It is projected that an additional 39,367 CBM wells and 3,200 conventional oil and gas wells would be developed over the next 10 years.

This alternative is a combination of the Companies' proposal and the BLM's RFD Scenario. BLM used the RFD Scenario's moderate level of development and the Companies' proposal to establish the overall level of development of CBM resources likely for this alternative. The Companies' proposal provided the basis for how they would implement the CBM portion of the alternative (drilling, completion, operation, and reclamation). BLM used the RFD Scenario to establish the overall level of additional development of non-CBM resources within the PRB.

The result of combining the Companies' proposal and the RFD Scenario is a Proposed Action that consists of two primary components. The first component is the CBM wells and their ancillary facilities. The second component is the non-CBM wells and their ancillary facilities. Because these two components use different technologies and techniques and involve different levels of disturbance, they are discussed separately.





POWDER RIVER BASIN OIL & GAS PROJECT FEIS

FIGURE 2-1
DISTRIBUTION OF EXISTING AND PROPOSED WELL PADS

ANALYSIS AREA: Campbell, Converse, Johnson & Sheridan Counties, Wyoming

DATE: 12/23/02	ArcView File: C:\1011_v1\data\maps.apr Layout--CBM_Well_Distribution
	DRAWN BY: MSH

Existing CBM Well location data provided by the Wyoming Oil and Gas Commission. Thunder Basin National Grassland data provided by the US Forest Service. All other data provided by the Bureau of Land Management--Buffalo Field Office and Casper Field Office.

Transverse Mercator Projection
1927 North American Datum
Zone 13

Coal Bed Methane Development

Under this alternative, the Companies would drill, complete, and operate 39,367 new CBM wells within the Project Area over a 10-year period (Table 2–1). Including the 12,024 CBM wells already drilled or permitted for drilling in the Project Area, the Companies would drill, complete, and operate 51,391 CBM wells by the end of 2011 (Figure 2–1 and Table 2–2).

The Companies also would construct the ancillary facilities needed to support these wells. The ancillary facilities include access roads; pipelines for gathering gas and produced water; electrical utilities; facilities for measuring and compressing gas; facilities for treating, discharging, disposing of, containing, or injecting produced water; and pipelines to transport gas to high-pressure transmission pipelines. These transmission pipelines would deliver the gas to market.

The overall life of the Proposed Action, including drilling, production, and reclamation, is expected to be about 20 years. Construction of the 39,367 new wells would begin during 2002. The Companies would drill these wells over a 10-year period (Table 2–1). The productive life of each well is expected to be about 7 years. Accordingly, production from at least some of the 39,367 new wells is expected to last until 2018 (because the first year of production was assumed to be the year the wells are drilled, a well drilled in 2011 would complete 7 years of production at the end of 2017). Final reclamation of these wells would occur during the 2 to 3 years after production ends. Thus, the Proposed Action would be completed around the end of 2020. As a result of the proposed schedule for drilling wells and the 7-year productive life, the cumulative number of wells producing CBM would increase rapidly over 5 years, peak at more than 35,000 during 2007, and steadily decline through 2017 (Figure 2–2).

Because of comments received on the draft, a review of average productive well life was conducted to see if estimates of well life used in the DEIS needed to be adjusted. To obtain an average well life, 264 CBM wells east of the Powder River were selected by searching the PI/Dwights database for wells with first production dates of December 31, 1996 or earlier. Of the 264 wells, 216 had enough data to calculate a well life and an estimated ultimate gas recovery (EUR). The other 58 wells were shut-in. The estimated average well life for the 216 wells was 8.5 years. Data also suggested average well lives of between 3 to 5 years. These wells are in areas where wells have already been drilled and now new wells are being drilled to in-fill between existing wells.

This same process was used to look at the history of wells on the west side of the PRB. Because of limited history, only 25 wells had data sufficient for estimating production life. The average production life for these wells was 4.3 years and the maximum was 8.25 years. This sample may not be representative of future conditions because of the limited number of wells involved.

Upon review, it was determined that the difference in average production life for the wells considered in the analysis was not sufficient to warrant changing the 7-year well life assumption used in the DEIS.

Table 2–1 Distribution of New Producing CBM Wells by Sub-watershed — Alternative 1

Sub-watershed	Year 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Total
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	101	277	277	277	277	277	277	277	277	272	2,589
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	2,785	2,640	2,640	2,514	2,499	2,499	2,012	488	455	435	18,967
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	10	6	7	6	8	0	0	0	0	0	37
Crazy Woman Creek	304	351	351	351	346	346	316	191	186	178	2,920
Clear Creek	263	400	400	400	405	405	405	361	359	355	3,753
Middle Powder River	45	102	102	102	102	102	102	102	102	97	958
Little Powder River	214	229	229	229	235	235	235	149	144	136	2,035
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	250	216	216	208	210	210	177	54	52	51	1,644
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	80	65	65	65	65	65	62	30	21	15	533
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	908	751	751	738	760	760	710	201	178	174	5,931
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0
Total	4,960	5,037	5,038	4,890	4,907	4,899	4,296	1,853	1,774	1,713	39,367

Source: BLM 2001e

Table 2–2 Distribution of All CBM Wells by Sub-watershed — Alternative 1

Sub-watershed	Pre-2002[1]	Year										Total
		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	819	101	277	277	277	277	277	277	277	277	272	3,408
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	2,808	2,785	2,640	2,640	2,514	2,499	2,499	2,012	488	455	435	21,775
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	0	10	6	7	6	8	0	0	0	0	0	37
Crazy Woman Creek	150	304	351	351	351	346	346	316	191	186	178	3,070
Clear Creek	389	263	400	400	400	405	405	405	361	359	355	4,142
Middle Powder River	727	45	102	102	102	102	102	102	102	102	97	1,685
Little Powder River	1,814	214	229	229	229	235	235	235	149	144	136	3,849
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	251	250	216	216	208	210	210	177	54	52	51	1,895
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	401	80	65	65	65	65	65	62	30	21	15	934
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	4,659	908	751	751	738	760	760	710	201	178	174	10,590
Middle North Platte River	6	0	0	0	0	0	0	0	0	0	0	6
Total	12,024	4,960	5,037	5,038	4,890	4,907	4,899	4,296	1,853	1,774	1,713	51,391

Note:

1. The Pre-2002 wells include wells already drilled (some of which are producing) and those projected for completion by 2002 (but not necessarily producing).

Source: BLM 2001e

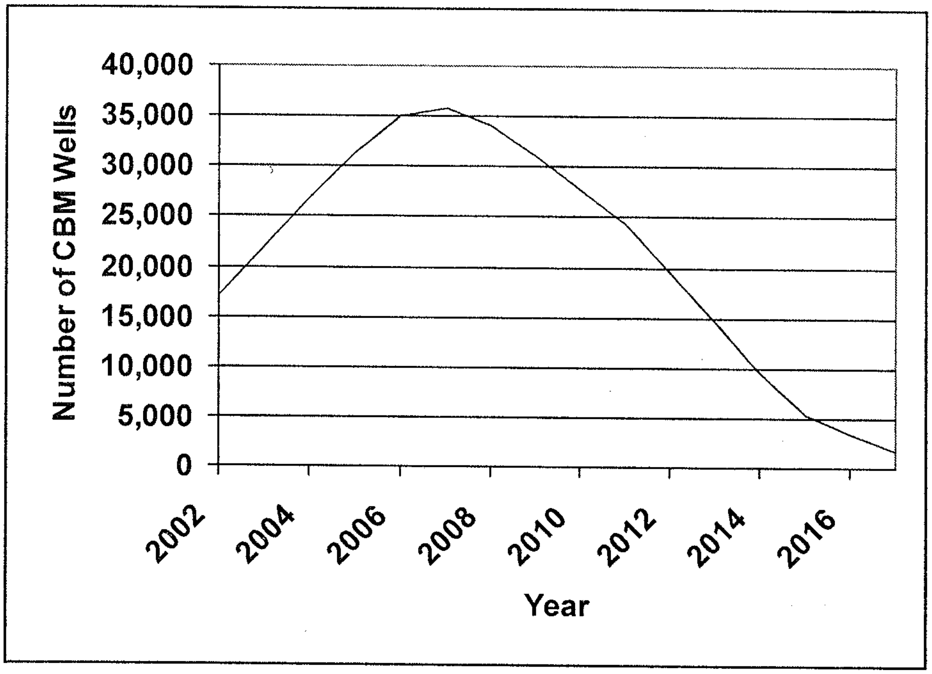


Figure 2–2 Cumulative Number of Producing CBM Wells Over the Productive Life of the Project

Several coal beds occur together in parts of the Project Area. Standard practice in these areas is to drill a separate well to develop each coal bed. Where possible, the Companies would collocate these wells on the same well pad. Based on this practice of collocation and knowledge of the locations of multiple coal beds likely to produce CBM, BLM and the Companies project the 39,367 new wells would be drilled from almost 26,000 well pads (Table 2–3). The total number of wells and well pads is based on an 80-acre spacing pattern overall (eight pads per square mile). Including the pads constructed for wells drilled before 2002, the 51,391 CBM wells would be distributed across almost 35,600 well pads (Table 2–4 and Figure 2–1). For this NEPA analysis, the number of wells on a pad was assumed to range from one to three. However, BLM recognizes the Companies are trying to develop the technology for multiple coal seam completions and encourages these efforts and its potential to reduce the number of wells drilled.

Under the Proposed Action, the Companies would drill, operate, and maintain wells and construct ancillary facilities in 10 of the 18 sub-watersheds that constitute the Project Area (Table 2–5). However, most of the new wells (63 percent) and facilities would be constructed in two sub-watersheds: the Upper Powder River and Upper Belle Fourche River. Other sub-watersheds with relatively high numbers of wells and facilities include Clear Creek, Crazy Woman Creek, Upper Tongue River, and Little Powder River.

Overall, implementation of the CBM portion of the Proposed Action could disturb as many as 193,589 surface acres, most associated with the construction of pipelines, roads, and water handling facilities (Table 2–6). Compressor stations would account for the smallest amount of the overall surface disturbance. Short-term disturbance would encompass about 3 percent of the Project Area.

Table 2–3 Distribution of New Well Pads by Sub-watershed — Alternative 1

Sub-watershed	Year 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Total
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	41	111	138	109	93	148	140	132	103	124	1,139
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,744	1,806	1,602	1,582	1,613	1,574	1,104	288	340	189	11,842
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	10	6	7	6	8	0	0	0	0	0	37
Crazy Woman Creek	304	319	225	235	217	194	153	103	88	60	1,898
Clear Creek	212	296	276	252	308	255	255	269	233	228	2,584
Middle Powder River	21	50	48	47	48	50	50	51	51	49	465
Little Powder River	137	162	135	142	154	118	149	74	108	86	1,265
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	232	195	192	184	202	169	162	46	44	25	1,451
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	80	65	65	65	65	65	62	30	21	15	533
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	809	627	629	583	586	578	574	114	153	130	4,783
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0
Total	3,590	3,637	3,317	3,205	3,294	3,151	2,649	1,107	1,141	906	25,997

Source: BLM 2001e

Table 2–4 Distribution of All CBM Well Pads by Sub-watershed — Alternative 1

Sub-watershed	Pre-2002	Year										Total
		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	397	41	111	138	109	93	148	140	132	103	124	1,536
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	2,254	1,744	1,806	1,602	1,582	1,613	1,574	1,104	288	340	189	14,096
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	0	10	6	7	6	8	0	0	0	0	0	37
Crazy Woman Creek	63	304	319	225	235	217	194	153	103	88	60	1,961
Clear Creek	231	212	296	276	252	308	255	255	269	233	228	2,815
Middle Powder River	438	21	50	48	47	48	50	50	51	51	49	903
Little Powder River	1,301	137	162	135	142	154	118	149	74	108	86	2,566
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	249	232	195	192	184	202	169	162	46	44	25	1,700
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	390	80	65	65	65	65	65	62	30	21	15	923
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	4,266	809	627	629	583	586	578	574	114	153	130	9,049
Middle North Platte River	6	0	0	0	0	0	0	0	0	0	0	6
Total	9,595	3,590	3,637	3,317	3,205	3,294	3,151	2,649	1,107	1,141	906	35,592

Source: BLM 2001e

Table 2–5 Summary of New CBM Facilities Comprising Alternatives 1, 2A, and 2B

		Roads		Poly Pipeline		Steel Pipeline	Electrical Line	Recip Compressors[1]		Booster Compressors[2]	
Sub-watershed	Well Pads	Improved (miles)	Two-track (miles)	2–3-inch (miles)	12-inch (miles)	12-inch (miles)	Overhead (miles)	(units)	(horsepower)	(units)	(horsepower)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	1,139	318	429	571	215	80	215	9	14,850	31	10,850
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	11,842	2,400	3,002	3,996	1,501	721	1,501	192	316,800	691	241,850
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	37	48	72	96	36	12	36	1	1,650	4	1,400
Crazy Woman Creek	1,898	490	680	905	340	128	340	21	34,650	72	25,200
Clear Creek	2,584	487	749	995	374	91	374	14	23,100	49	17,150
Middle Powder River	465	141	155	207	78	39	78	3	4,950	9	3,150
Little Powder River	1,265	526	872	1,161	436	67	436	9	14,850	30	10,500
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	1,451	1,589	3,038	4,041	1,519	50	1,519	11	18,150	40	14,000
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	533	168	137	182	69	61	69	5	8,250	16	5,600
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	4,783	969	1,483	1,973	743	159	743	33	54,450	118	41,300
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0
Total	25,997	7,135	10,619	14,127	5,311	1,408	5,311	298	491,700	1,060	371,000

Notes:

1. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
2. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.

Source: BLM 2001e

Table 2–6 Summary of Estimated Short-term CBM Disturbance Associated with Alternative 1

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	632	59	1,542	520	2,075	782	2,408	248	727	782	10	12	9,796
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	4,978	435	11,635	3,639	14,529	5,458	10,527	2,408	6,327	5,458	175	232	65,801
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	11	1	234	88	350	132	26	24	121	132	5	4	1,128
Crazy Woman Creek	774	67	2,374	824	3,288	1,234	1,956	364	1,187	1,234	25	24	13,350
Clear Creek	1,009	86	2,363	908	3,623	1,362	3,547	320	778	1,362	10	18	15,387
Middle Powder River	238	22	682	188	752	283	690	206	267	283	5	6	3,622
Little Powder River	534	47	2,548	1,058	4,222	1,586	1,465	327	485	1,586	15	12	13,885
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	474	38	7,703	3,683	14,694	5,524	1,175	191	417	5,524	20	14	39,457
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	160	12	812	166	662	249	381	291	455	249	10	6	3,453
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	1,664	136	4,701	1,798	7,176	2,702	4,834	473	1,455	2,702	30	40	27,710
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	10,474	903	34,593	12,871	51,372	19,312	27,009	4,852	12,217	19,312	305	368	193,589

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.

Source: BLM 2001e

After pipelines had been reclaimed and other facilities, such as well pads, had been reclaimed in part, the Proposed Action's long-term disturbance from CBM development would encompass about 85,884 acres (Table 2–7). The long-term disturbance is a 44 percent reduction from the total short-term disturbance. The roads and water handling facilities would represent most of the long-term disturbance.

The following sections describe the Proposed Action in detail. Implementation would occur in three primary phases: drilling of wells and construction of production facilities, production and maintenance, and decommissioning and reclamation. Consequently, the detailed description of the Proposed Action is organized by these three primary phases.

Drilling of Wells and Construction of Production Facilities

This section describes the overall procedures, techniques, and resources the Companies would use to construct roads, well pads, and ancillary production facilities and to drill, case, and complete the CBM wells.

Well Access Roads

Most roads to well pads (resource roads) would be developed in two steps. Initially, each road would be roughed in as a two-track road. Generally, BLM requires improved graded and graveled roads to non-CBM operations. However, because the need to travel to the CBM wells is normally very limited, BLM has waived the blanket requirements for road improvements to minimize surface disturbance. Any need for surfacing or other upgrading would be established in consultation with BLM or other landowner based on site-specific conditions. In some cases, roads may require upgrading before the wells can be drilled. However, the road would be reclaimed if the well is not completed successfully and is plugged. The procedures for reclaiming roads are described in the section on decommissioning and reclamation of roads beginning on page 2–39.

Unless work is needed to alleviate concerns about safety, environmental issues, or access difficulties, the Companies would maintain roads used to access well pads in a two-track status. Areas where work may be needed include stream drainage crossings, low-water crossings, and rough topography. Gravel may be applied to problem areas. In addition, travel on two-track roads would be rescheduled or postponed during the infrequent periods of wet weather when vehicular traffic could cause rutting. Should BLM identify the need or be notified by a regulatory agency to take action regarding emergency conditions, such as extreme fire hazard, it would impose limitations as needed under conditions of the oil and gas lease terms.

BLM's experience in more rugged terrain, such as within the Powder River drainage, suggests that construction of a more substantial access road to the well pad using cut and fill construction techniques may be necessary about 20 percent of the time within the Project Area. Surface disturbance associated with crowning and ditching (normally required by BLM's general policy on design and construction of oil and gas well access roads) would occur only as required for access roads that traverse steeper terrain or rough, broken topography, or in other exceptional site-specific circumstances.

Table 2–7 Summary of Estimated Long-term CBM Disturbance Associated with Alternative 1

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	259	24	1,542	520	0	0	2,408	0	0	261	10	12	5,035
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,897	174	11,635	3,639	0	0	10,527	0	0	1,819	175	232	30,098
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	0	234	88	0	0	26	0	0	44	5	4	404
Crazy Woman Creek	292	27	2,374	824	0	0	1,956	0	0	411	25	24	5,933
Clear Creek	376	35	2,363	908	0	0	3,547	0	0	454	10	18	7,711
Middle Powder River	96	9	682	188	0	0	690	0	0	94	5	6	1,770
Little Powder River	204	19	2,548	1,058	0	0	1,465	0	0	529	15	12	5,850
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	164	15	7,703	3,683	0	0	1,175	0	0	1,841	20	14	14,615
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	53	5	812	166	0	0	381	0	0	83	10	6	1,516
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	593	55	4,701	1,798	0	0	4,834	0	0	901	30	40	12,952
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	3,937	363	35,593	12,871	0	0	27,009	0	0	6,437	305	368	85,884

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.

Source: BLM 2001e

In general, the Companies would reclaim access roads that are not needed for production (such as access roads to plugged and reclaimed wells) as soon as practical. However, the Companies could leave in place roads that have value for ranching or agricultural uses with the concurrence of the surface owner.

Well Pads

The minimum area required for a well pad would vary by company. Initially, the sizes of well pads would range from a minimum of 0.3 acre (100 feet by 150 feet) to a maximum of about 0.7 acre (175 feet by 175 feet). When a well is successfully completed, portions of the well pad that are not needed for production equipment and activities would be reclaimed. Over the long term, the size of well pads would be reduced to a minimum of about 0.1 acre (75 feet by 75 feet) for pads with one well to about 0.3 acre (115 feet by 115 feet) for pads with three wells.

Construction at a well pad would be minimal. At level well pads, only small amounts of vegetation or soil would be cleared. At each drill site, a temporary mud/reserve pit approximately 6 feet deep, 10 feet wide, and up to 30 feet long would be excavated, used during drilling and completion operations, and then reclaimed by evaporating the water, burying the solids, and revegetating the surface.

In areas where the surface of the ground is too steep to allow a drill rig to set up over native ground, the Companies would use limited cut and fill construction techniques to level a work area. Use of cut and fill construction techniques for well sites may be necessary at an estimated 20 percent of the sites. Areas that are disturbed, but are not needed for production, would be reclaimed as soon as practical after drilling ends.

Drilling

When the access road is complete and the well pad (if needed) has been prepared, a mobile drilling rig would be driven to the site and erected. Typically, the Companies use a truck-mounted water well type of drilling rig to drill CBM wells in the Project Area. Additional equipment and materials needed for drilling operations, including water, would be trucked to the site. On average, drilling would require about 26,000 gallons (0.08 acre-feet) of water per well for preparing cement, developing the well, controlling dust, and drilling (non-toxic drilling mud is required to handle certain down-hole conditions). Drilling mud usually is native mud and bentonite. As conditions in the hole dictate, small amounts of polymer additives or potassium chloride salts may be added to clean the hole and stabilize the clay.

WOGCC and BLM currently require (under Federal Onshore Oil and Gas Order No. 2 and WOGCC's drilling rules located at Section 22 of Chapter 3) that surface casing of 60 feet or 10 percent of the total depth of the well be set with cement returns to the surface. Individual wells are drilled as follows. A well is drilled to a depth of 350 feet to 1,500 feet or deeper to the top of a coal zone. The well control system is designed to meet the conditions likely to be encountered in the hole and would be in conformance with the requirements of BLM and the State of Wyoming. At a minimum, WOGCC and BLM require a diverter after the surface casing is set.

Drilling and completion operations for a CBM well normally involve about 7 to 15 employees, including personnel for logging and cementing. Each well would be drilled within 1 to 3 days. When the target coal is reached, the well production casing would be placed and cemented. Placement of production casing (casing the hole) would include insertion of a steel pipe into the drill hole from the bottom of the hole to the surface. Casing would be set into the hole one joint at a time and would be threaded at one end with a collar located at the other end to connect each joint.

The casing would be cemented into place by pumping a slurry of dry cement and water into the casing head, down through the casing string to the bottom, and then up through the spacing between the casing and the well (annulus). A plug and water flush then would be pumped to the bottom of the well to remove any residual cement from the inside walls of the casing. Sufficient cement would be pumped into the annulus to fill the space, where it would be allowed to harden.

If indications of inadequate primary cementing of the surface exist, intermediate or production casing strings, such as lost returns, cement channeling, or mechanical failure of equipment, the operator would evaluate the adequacy of the cementing operations. This evaluation would consist of pressure testing the casing shoe, running a cement bond log, cement evaluation tool log, or a combination thereof.

Cementing the annulus around the casing pipe restores the original isolation of formations by creating a barrier to the vertical migration of fluids and gas between rock formations within the borehole. It also protects the well by preventing pressure in the formation from damaging the casing and retards corrosion by minimizing contact between the casing and corrosive formation waters.

Once the cement sets up or hardens behind the casing, the coal zone would be drilled using either air or water. The size of the hole in the coal below the casing is enlarged using an upreamer bit that may extend out to an 18-inch diameter or more. The well would be completed "open hole" in the coal without inserting any more steel casing in the hole.

After the coal zone is drilled, the open hole may be flushed with clean chlorinated water (from approved and properly permitted facilities) to remove the coal fines from the hole. Steel tubing then would be inserted inside the casing and in the open hole. A submersible electric pump would be attached to the bottom end of the tubing to pump water from the coal. The size and capacity of the submersible pump would depend on the coal's thickness and the rate of production expected from the well. Most pumps are rated at 10 to 20 gallons per minute (gpm). The pump is attached because water pressure in the coal zone must be reduced before gas (methane) will flow to the open hole. The water would be pumped up the tubing to the surface where, generally, it would be gathered in a pipeline for disposal. When the gas is released from the coal, it flows up the space between the tubing and the steel casing to the gas-gathering system and compressors at the surface.

When the well is complete, all disturbed areas that are not needed for production facilities would be restored. The mud pit would be dried and backfilled. These areas would be seeded as soon as practicable.

Wells determined to be unsuccessful would be plugged, abandoned, and then reclaimed. Abandonment would follow the procedures set forth by WOGCC, BLM, or both. Reclamation would be completed according to the BLM's regulations and the agreement with the surface owner.

Well Production Facilities

After well productivity is established, a small area about 5 to 6 feet square would be leveled and a weatherproof covering or box would be placed over the wellhead. Enclosures for wellheads and metering facilities would be vented. Usually, a metal fence or rail would be installed immediately around the box and electrical panel to protect them from livestock. Meters to measure pressure and rates of water production may be placed in the box. There would be no pump jacks at the wellhead site; however, injection facilities, including some treatment facilities, likely would be collocated at CBM wells. The power lines for the submersible water pump would be laid in trenches, usually with water pipelines, and would not be placed on poles to minimize surface disturbance and the visual impact of the Proposed Action.

Pipelines

Three types of pipelines would be constructed as part of the Proposed Action. These pipelines are intended to gather gas and produced water and to deliver gas at high pressure. The gathering pipelines would convey gas from the wells to compressor facilities and the produced water to discharge or disposal points. The high-pressure gas pipelines would connect compressor facilities to the existing and proposed transmission pipelines. Rights-of-way for the pipelines would vary from 20 to 50 feet for polyethylene pipeline and would be 100 feet for steel pipelines.

All three types of pipelines would be installed along access roads to minimize disturbance, except where topography or concerns of surface owners dictate otherwise. Pipelines to gather gas and produced water would be placed together in the same trench or ditch. High-pressure pipelines would be installed in a separate ditch. The pipelines to gather gas and produced water would be constructed of polyethylene pipe with an outside diameter of 2 to 12 inches. The high-pressure pipelines would be constructed of steel pipe with an outside diameter of 12 to 16 inches.

Usually, the pipeline to gather gas would be laid in a ditch constructed by a small mechanical-belt ditching machine. This method of construction would involve very little surface disturbance and clearing of little or no vegetation. The construction right-of-way for gas-gathering pipelines would range from 20 to 50 feet. The actual width of the trench would range from 18 to 36 inches. Depth of cover over the pipelines would be a minimum of 36 inches.

Generally, construction of pipelines would occur in a planned sequence of operations and along roads where possible. Where feasible, trees would be avoided. Brush and woody vegetation would be left in place and driven over as necessary (crushed but potentially capable of redeveloping a vegetative canopy). If necessary, the path would be cleared of trees and heavy brush by brush beating or lightly blading the surface. Soils would be left undisturbed over much of the construction work area, although some compaction may occur. Pipelines would cross streams according to the requirements of permitting under Section 404 of the Clean Water Act. Overall, the crossings would be constructed to minimize the length and the locations of the crossings would be returned to their approximate original configurations. Reclamation would begin immediately after the pipeline is buried.

WDEQ requires a general construction storm water permit for surface disturbance under the storm water permitting program that is part of the National Pollutant Discharge Elimination System (NPDES). These permits authorize storm water discharges from construction projects that clear, grade, excavate, or otherwise disturb five or more acres (one or more acres starting in 2003). They require preparation of a storm water pollution prevention plan (SWPPP) that is intended to identify potential sources of pollutants and describe best management practices (BMPs) that would be employed to prevent transport of pollutants off site.

Facilities to Gather and Dispose of Produced Water

Polyethylene pipe 2 to 3 inches in diameter would be connected to the tubing in the well and brought underground in a trench to a point of discharge into a natural drainage or into containment for disposal. The current average rate of water production per well, according to WOGCC, is about 10 gpm (Likwartz 2001). This rate for an individual well may rise as deeper, thicker coals are produced. Higher rates are expected in the Powder River sub-watershed where the Big George Coal reaches a maximum thickness of about 200 feet. About half the wells drilled under this alternative would be in the Powder River drainage basin. The Companies are aware of this issue and have already initiated watershed studies to address water issues in three of the major tributaries of the Powder River where drilling is occurring or is about to occur. Historically, based on production information available on the WOGCC website, the rate of water production drops to one-half its initial level after the first year of production in a new area where the water pressure is being reduced before gas production begins. Additionally, the U.S. Department of Energy's National Energy Technology Laboratory determined from "type wells" in the PRB that more than half of the water is produced during the first 2 years (Advanced Resources International 2002). The maximum production rate over the entire Project Area is expected to occur in 2006 with about 386,000 acre-feet of water per year (Table 2–8).

The method of handling produced water would vary as the water quality, water volumes, and desires of the surface owner change. Potential water handling methods include direct surface discharge, treatment of produced water followed by direct surface discharge, containment of produced water, and injection of produced water through disposal wells (Table 2–9). Presently, the primary method of disposal is to convey the water via underground pipe to a surface discharge location mutually selected by the operator and the surface owner or lessee. WDEQ permits discharges after an NPDES permit is issued. The following sections describe the assumptions developed for the analysis of water handling methods.

Table 2–8 Projected Amount of Water Produced from CBM Wells Under Alternatives 1, 2A, and 2B

	Water Produced (in acre-feet)[1]																
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	11,019	16,950	20,272	22,133	22,351	19,945	20,282	15,782	15,782	15,654	8,646	4,721	2,522	1,290	601	214	198,164
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	100.512	137,942	159.034	167,608	171.423	163,521	147,481	88,046	60,319	44,169	23,697	12,169	5,672	2,242	1.032	366	1.285,233
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	263	306	356	358	412	232	131	69	36	17	7	0	0	0	0	0	2,187
Crazy Woman Creek	9,449	15,185	18,418	20,240	21,135	21,036	20,279	15,962	13,716	12,240	6,731	3,629	1,881	910	422	150	181,383
Clear Creek	10,697	18,192	22,415	24,795	26,267	25,997	24,879	22,762	22,071	21,576	11,969	6,552	3,500	1,780	832	299	244,583
Middle Powder River	8,257	10,421	11,640	12,328	12,044	9,897	9,689	6,030	6,030	5,899	3,276	1,797	964	495	231	82	99,080
Little Powder River	18,613	20,822	21,832	22,427	21,330	18,607	19,121	8,016	7,124	6,439	3,930	2,340	1,335	699	350	133	173,118
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	15,460	17,271	17,685	17,503	17,385	16,180	12,613	5,226	3,574	2,956	1,041	363	124	40	13	3	127,437
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	7,978	8,421	8,365	8,275	8,228	7,002	5,897	2,144	1,456	1,013	357	125	43	14	4	1	59,323
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	54,735	67,481	76,259	82,713	85,761	84,507	79,493	49.435	39,170	31.277	21,215	13.495	7,630	3,347	1,849	790	699.157
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	236,983	312,991	356,276	378,380	386,336	366,924	339,865	213,472	169,278	143,251	80,869	45,191	23,671	10,817	5,334	2,038	3,069,665

Note:
1. Volumes shown include produced water from pre-2002 wells as well as the new CBM wells.
Sources: BLM 2001e and Meyer 2002b.

Table 2–9 Assumed Water Handling Methods for CBM Wells under Alternatives 1 and 3

	Water Handling Method[1,2,3]						
	NPDES-permitted Discharge						
Sub-watershed	Untreated Discharge (percent)	Passive Treatment (percent)	Active Treatment (percent)	Infiltration Impoundment (percent)	Containment Impoundment (percent)	LAD (percent)	Injection (percent)
Upper Tongue River	0	35	0	45	10	0	10
Upper Powder River	75	0	0	15	5	0	5
Salt Creek	55	0	0	35	5	0	5
Crazy Woman Creek	70	0	0	5	5	15	5
Clear Creek	25	10	0	40	5	10	10
Middle Powder River	60	5	0	10	10	10	5
Little Powder River	65	0	0	10	10	10	5
Antelope Creek	55	0	0	35	5	0	5
Upper Cheyenne River	55	0	0	35	5	0	5
Upper Belle Fourche River	45	0	0	40	5	0	10

Notes:

1. The percentages shown represent the distribution of water handling methods assumed for the analysis, not the amount of water that actually reaches the river.
2. Handling Methods:
   NPDES-permitted Discharge – includes methods of handling the produced water that require an NPDES permit.
   Untreated discharge – water that is discharged onto the surface of the ground without any treatment.
   Passive treatment – water that is amended through passive methods to meet standards before discharge. An example of this method is passing the water over scoria to remove iron.
   Active treatment – water that is amended through active methods to meet standards before discharge. An example of this method is passing the water through a reverse osmosis system.
   Infiltration impoundment – water contained in upland and bottomland impoundments allowing for infiltration and groundwater recharge. Infiltration impoundments constructed in-channel may allow for overflow under given storm events.
   Containment impoundment – includes upland impoundments, lined, with minimal infiltration and no direct surface discharge or lateral subsurface movement of water and down-gradient expression in seeps or springs. These impoundments would be permitted by WOGCC.
   LAD = land application disposal. Typically, land application is achieved by spraying produced water through agricultural irrigation equipment and high-pressure atomizers.
   Injection – represents that water that is injected into disposal wells.
3. The above percentages are not upper thresholds that can or would be enforced. They are merely a disclosure of effects of one of many various ways water may be handled to meet Wyoming's water quality standards and agreements with bordering states.

Assumptions in the Analysis of Surface Discharge

Produced water from CBM wells would be gathered for discharge at outfalls authorized according to guidance and requirements of the State of Wyoming (WDEQ and, possibly, WSEO). Surface discharge facilities of varying sizes would be constructed; however, an average facility, described below, was analyzed for this analysis. On average, five wells would discharge together at the same outfall. Outfalls may feed into small stock reservoirs or other treatment facilities before the outflows reach surface drainages. Water produced from CBM wells that is discharged to the surface may be suitable for irrigation and may be diverted for that purpose. On average, all facilities associated with untreated or passively treated surface discharge for up to 20 CBM wells (estimated to be four "bubbler" outfalls, a stock pond, and an armored stream channel for this analysis) would encompass an estimated 6 acres, or approximately 0.3 acres per well. On average, all facilities associated with actively treated surface discharge for CBM wells also would encompass approximately 0.3 acres per well.

Assumptions in the Analysis of Infiltration Impoundments

Produced water from CBM wells would be gathered for discharge into infiltration impoundments that would be on-channel and off-channel. The impoundments would be designed and authorized according to guidance and requirements of the State of Wyoming (WDEQ, WOGCC, and WSEO).

Shallow impoundments with a dam height of 15 feet on average, including 5 feet of freeboard, would be constructed. Infiltration impoundments of varying sizes would be constructed; however, this analysis assumed an average impoundment would encompass 6 acres and have a capacity of 50 acre-feet to estimate the potential surface disturbance associated with this method of handling water. Impoundments with a dam height greater than 20 feet or a storage capacity of 50 acre-feet or more would be regulated under the Safety of Dams Law and would require certification by a Wyoming-licensed professional engineer.

Only for the purpose of estimating the surface disturbance associated with this method of handling water produced from CBM wells, the wells were projected to produce water at the average rate of 4.8 gpm over their productive life. Enhanced evaporation would reduce water impounded by the 6-acre reservoir by 4 feet per year, on average (Environmental Protection Agency [EPA] 2001b). Infiltration also would reduce the water impounded by the reservoir by 4 feet per year (EPA 2001b). In addition, estimates for storage for this average impoundment assumed an amount of water equivalent to the precipitation occurring over the reservoir would be used beneficially each year. Based on these assumptions, water in this average impoundment would be 4 feet deep at the end of 3 years and would be 8 feet deep at the end of 7 years. Reclamation of each impoundment would begin about 1 year after the inflow of water produced from CBM wells ends, which would allow time for evaporation and infiltration of water contained in the impoundment when inflow ends.

On average, each impoundment would handle all water produced from seven CBM wells. The impoundment, including embankments, drainage structures that divert natural runoff away from the impoundment, outlet works, fences that exclude livestock or wildlife (if used), and an adequate working area for excavations would disturb 8 acres (1.1 acres per CBM well). The slopes of the embankment would be 3:1 and would a 12-foot-wide flat area along the top of the embankment to allow for heavy equipment. About half of the impoundment would be excavated below the natural level of the ground. The impoundment would not be netted.

Assumptions for Containment Analysis

Water produced from CBM wells would be gathered for discharge into containment impoundments that are located off-channel. The impoundments would be designed and authorized according to guidance and regulations of the State of Wyoming (likely WDEQ, WSEO, WOGCC, or some combination of the three) where containment is selected as the option for handling water produced from CBM wells because of the water's poor quality.

Containment impoundments would vary in size; however, this analysis evaluated an average sized containment impoundment. This impoundment would have a 15-foot tall dam that has 2 feet of freeboard. It would encompass 50 acres and have a capacity of 450 acre-feet. Impoundments with a dam height greater than 20 feet or a storage capacity of 50 acre-feet or more would be regulated under the Safety of Dams Law and would require certification by a Wyoming-licensed professional engineer.

To estimate the surface disturbance associated with this method of handling water produced from CBM wells, the wells were projected to produce water at the average rate of 4.8 gpm over their productive life. Enhanced evaporation would reduce water impounded by the 50-acre reservoir by 4 feet per year, on average (EPA 2001b). Ten percent of the inflow would be lost to soil moisture resulting from the limitations of the earthen materials used to line the impoundment. In addition, estimates for storage for this average impoundment assumed an amount of water equivalent to the precipitation occurring over the reservoir would be used beneficially or lost through the use of enhanced methods of evaporation, such as misting or aeration, each year. Based on these assumptions, water in this average impoundment would be 4 feet deep at the end of 3 years and would be 8 feet deep at the end of 7 years. Reclamation of each impoundment would begin about 2 years after the inflow of water produced from CBM wells ends, which would allow time for evaporation of water contained in the impoundment when inflow ends.

On average, each impoundment would handle all of the water produced from 40 CBM wells. The impoundment, including embankments, drainage structures that divert natural runoff away from the impoundment, outlet works (if used), fences that exclude livestock or wildlife (if used), and an adequate working area for excavations would disturb 70 acres (1.8 acres per CBM well). The slopes of the embankment would be 3:1 and would a 12-foot-wide flat area along the top of the embankment to allow for heavy equipment. About half of the impoundment would be excavated below the natural level of the ground. The impoundment would not be netted.

Assumptions in Analysis of Land Application Disposal

All water produced over the life of 40 wells would be spread on the land surface of a land application disposal (LAD) site using atomizers or irrigation equipment. All water would be contained within the LAD site. An estimated 100 percent of the water would be used consumptively. Infiltration and channelized surface runoff would be negligible. Each LAD site was assumed for this analysis to disturb an estimated 64 acres or an estimated 1.6 acres per well.

Disposal likely would be accomplished using a disposal-rest rotation cycle consisting of repeated phases of disposal, soil amendment, rest, and disposal until the limitations of repeated soil amendments are reached, and a portion of the site would be reclaimed. LAD sites would not be designed as traditional irrigation sites, in that irrigation return flows would not be anticipated because the produced water would be applied at agronomically acceptable rates and consumptive use by crops would be 100 percent.

Assumptions in Analysis of Injection

Water produced from six to 10 CBM wells would be gathered for injection into the Fort Union Formation or a lower injection zone. This analysis assumed that, on average, injection well facilities, including water transfer facilities, flowlines, and roads that serve eight CBM wells would disturb an estimated 12 acres, or approximately 1.5 acres per well.

Central Metering Facilities

Typically, natural gas produced from each well is individually measured and mechanically or electronically recorded at a central point or central metering facility (CMF). Gas-gathering pipelines for an average of 10 wells would be tied together in a CMF, where all the connected wells would be metered. At the CMF, gas would be commingled into the gas-gathering system, which would transport it to the compressor station. An improved road would be constructed to each CMF, which would disturb an area no wider than 50 feet. Construction of each CMF would disturb about 0.2 acre (100 feet by 100 feet) for the short term. This disturbance would be reduced to about 0.1 acre (50 feet by 80 feet) for the long term.

The wells connected to a CMF may produce water for some time (occasionally more than a year) before natural gas (methane) is produced. The water produced would be disposed of using methods that meet standards of WDEQ, BLM, WOGCC, and WSEO. Small amounts of gas may be produced in the initial stages of depressurizing the coal bed. This gas may be vented until sufficient volumes are produced to run a first-stage compression system near the CMF. Any gas would be vented according to BLM's Notice to Lessees 4A (Royalty or Compensation for Oil and Gas Lost), and Onshore Order No. 5 (Measurement of Gas) and by permission of WOGCC and BLM in Sundry Notices. Immediately after a volume capable of sustaining compression operations has been reached, the wells that produce gas would be shut in until the necessary pipeline connections are made.

Production of natural gas (methane) is expected to reach a maximum rate for the entire Project Area of almost 3.6 billion cubic feet per day (bcf) in 2006 and 2007. Current estimates of the total recoverable reserve range from 13 to 25 trillion cubic feet of gas (BLM 2001f). Other estimates suggest that total recoverable reserves range from 12 to 37 trillion cubic feet of gas (Crockett et al. 2001).

Electrical Power Utilities

Although the Companies would use gas-fired compressors, other equipment, such as pumps, would be electric. In addition, natural gas-fired and diesel engine-powered generators may be used temporarily at individual wells until electrical distribution lines are constructed.

Based on projected power demands, it is anticipated that the Companies would require 0.5 megawatt (MW) per day to transport 3 bcf of natural gas per day using gas-fired compression. Based on this power demand, the maximum power requirement would be 0.6 MW per day.

Under this alternative, three-phase, 24.9-kilovolt (kV) distribution lines would connect wells and compressor facilities with the existing transmission and distribution system in the Project Area. Electricity would be routed to compressor stations and CMFs on poles above ground, generally located along the access roads or on additional rights-of-way (30 feet wide) across open land. Between the CMFs and wells, the secondary electric service power lines (480 volt) would be buried in the same trenches with the pipelines to gather gas and produced water. The installation and power would be provided by the utility company that supplies these services. Construction of the power lines would follow the access roads and would coincide with the completion of well drilling. The power lines would be designed and constructed according to the Avian Power Line Interaction Committee's (1996) guidelines for the prevention of electrocution of raptors.

The aboveground power lines would be constructed using tracked and wheeled equipment. Holes for the poles would be located to not disturb existing sensitive vegetation and would be excavated to a depth of 6 to 8 feet. Poles and other structural components would be transported to the construction site, where they would be assembled and then erected by a boom truck.

Poles could be moved if topography or impacts to cultural, vegetative, or wildlife resources are identified at the site of the structure. Vegetation would be cleared, typically with hand-held equipment in areas of thick vegetation or where vegetation may impede the performance of the active line.

All aboveground electric lines typically would be installed on 35-foot tall poles. Poles would be required approximately every 300 feet. Approximately 5,311 miles of aboveground power lines would be installed in the Project Area (Table 2–5). The short-term surface disturbance for these lines would be 19,312 acres (Table 2–6). The long-term surface disturbance for the power lines would be 6,437 acres (Table 2–7).

Gas-Delivery System

The delivery system consists of components that would deliver gas produced from the wells (Table 2–10) to the high-pressure transmission pipelines that would transport the gas to market. These components include compressor stations and pipelines. This section describes these primary components of this gas-delivery system.

The Companies would construct two types of compressor stations: central reciprocating and booster stations. Produced natural gas under pressure from the wellhead would move through the low-pressure gas-gathering system to a booster compressor station. Typical pressure in the gathering line is less than 50 pounds per square inch (psi). At booster stations, low (350) horsepower (HP) natural gas or electric-powered boosters or blowers would enhance the flow of gas through certain pipelines. As shown on Table 2–11, the Companies expect to construct almost 1,060 new booster compressors. These compressors would be distributed among as many as 184 stations (Table 2–12).

Gas from the booster compressor stations would flow through medium-pressure pipelines (50 to 125 psi) to the central reciprocating compressor stations. High horsepower (1,650 HP) compressors at these stations would increase the pressure of natural gas to an estimated 700 to 1,450 psi to facilitate transmission of the natural gas to high-pressure transmission pipelines. As shown on Table 2–13, the Companies expect to construct almost 298 new reciprocating compressors. These units would be distributed among as many as 61 new stations (Table 2–14).

Table 2–10 Projected Amount of Natural Gas Produced from CBM Wells under Alternative 1

	Total Cubic Feet of Methane Produced per Day by Year (in mmcf)									
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Little Bighorn River	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	22	36	56	72	84	89	91	92	92	92
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,078	1,705	2,056	2,284	2,319	2,301	2,225	1,905	1,317	819
South Fork Powder River	0	0	0	0	0	0	0	0	0	0
Salt Creek	7	11	13	15	15	14	14	12	8	4
Crazy Woman Creek	96	157	196	224	233	234	230	206	160	120
Clear Creek	56	88	115	135	147	152	155	154	147	141
Middle Powder River	8	12	18	22	26	27	27	27	27	27
Little Powder River	56	82	95	103	106	107	108	105	92	81
Little Missouri River	0	0	0	0	0	0	0	0	0	0
Antelope Creek	80	120	137	147	147	145	141	123	91	63
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	30	45	51	55	55	56	56	55	48	42
Lightning Creek	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	280	398	440	460	456	453	448	407	314	231
Middle North Platte River	0	0	0	0	0	0	0	0	0	0
Total	1,713	2,654	3,177	3,517	3,588	3,578	3,495	3,086	2,296	1,620

Source: Jones 2001

Table 2–11 Distribution of New Booster Compressor Units by Year and Sub-watershed — Alternative 1

Sub-watershed	Year							Total
	2002	2003	2004	2005	2006	2007	2008	
Little Bighorn River	–	–	–	–	–	–	–	–
Upper Tongue River	3	6	8	6	5	2	1	31
Middle Fork Powder River	–	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–	–
Upper Powder River	195	250	141	91	14			691
South Fork Powder River	–	–	–	–	–	–	–	–
Salt Creek	1	2	1	–	–	–	–	4
Crazy Woman Creek	17	24	16	11	4	–	–	72
Clear Creek	10	13	11	8	4	2	1	49
Middle Powder River	2	1	3	1	2	–	–	9
Little Powder River	9	10	5	4	1	–	1	30
Little Missouri River	–	–	–	–	–	–	–	–
Antelope Creek	14	15	7	4	–	–	–	40
Dry Fork Cheyenne River	–	–	–	–	–	–	–	–
Upper Cheyenne River	6	5	3	1	1	–	–	16
Lightning Creek	–	–	–	–	–	–	–	–
Upper Belle Fourche River	47	47	17	7	–	–	–	118
Middle North Platte River	–	–	–	–	–	–	–	–
Total	304	373	212	133	31	4	3	1,060

Source: BLM 2001e

Table 2–12 Distribution of Booster Compressors by Size of Station and Sub-watershed — Alternative 1

Sub-watershed	Booster Stations						Total
	1-Unit	2-Unit	3-Unit	4-Unit	5-Unit	6-Unit	
Little Bighorn River	–	–	–	–	–	–	–
Upper Tongue River	–	–	1	1	–	4	6
Middle Fork Powder River	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–
Upper Powder River	–	–	1	1	–	114	116
South Fork Powder River	–	–	–	–	–	–	–
Salt Creek	1	–	1	–	–	–	2
Crazy Woman Creek	–	–	–	–	–	12	12
Clear Creek	–	–	1	1	–	7	9
Middle Powder River	1	–	–	2	–	–	3
Little Powder River	–	–	2	–	–	4	6
Little Missouri River	–	–	–	–	–	–	–
Antelope Creek	–	–	–	1	–	6	7
Dry Fork Cheyenne River	–	–	–	–	–	–	–
Upper Cheyenne River	–	–	–	1	–	2	3
Lightning Creek	–	–	–	–	–	–	–
Upper Belle Fourche River	–	–	–	1	–	19	20
Middle North Platte River	–	–	–	–	–	–	–
Total	2	0	6	8	0	168	184

Source: BLM 2001e

Table 2–13 Distribution of New Reciprocating Compressors by Year and Sub-watershed — Alternative 1

Sub-watershed	Year 2002	2003	2004	2005	2006	2007	2008	Total
Little Bighorn River	–	–	–	–	–	–	–	–
Upper Tongue River	1	2	2	1	2	–	1	9
Middle Fork Powder River	–	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–	–
Upper Powder River	54	70	39	25	4	–	–	192
South Fork Powder River	–	–	–	–	–	–	–	–
Salt Creek	–	1	–	–	–	–	–	1
Crazy Woman Creek	5	7	4	3	1	1	–	21
Clear Creek	3	3	3	3	1	–	1	14
Middle Powder River	–	1	–	1	–	–	1	3
Little Powder River	3	3	1	1	–	–	1	9
Little Missouri River	–	–	–	–	–	–	–	–
Antelope Creek	3	5	2	1	–	–	–	11
Dry Fork Cheyenne River	–	–	–	–	–	–	–	–
Upper Cheyenne River	2	1	1	1	–	–	–	5
Lightning Creek	–	–	–	–	–	–	–	–
Upper Belle Fourche River	13	13	4	3	–	–	–	33
Middle North Platte River	–	–	–	–	–	–	–	–
Total	84	106	56	39	8	1	4	298

Source: BLM 2001e

Table 2–14 Distribution of Reciprocating Compressors by Size of Station and Sub-watershed — Alternative 1

Sub-watershed	Reciprocating Stations 1-Unit	2-Unit	3-Unit	4-Unit	5-Unit	6-Unit	Total
Little Bighorn River	–	–	–	–	–	–	–
Upper Tongue River	–	–	1	–	–	1	2
Middle Fork Powder River	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–
Upper Powder River	–	–	6	–	–	29	35
South Fork Powder River	–	–	–	–	–	–	–
Salt Creek	1	–	–	–	–	–	1
Crazy Woman Creek	–	–	3	–	–	2	5
Clear Creek	–	1	–	–	–	1	2
Middle Powder River	–	–	1	–	–	–	1
Little Powder River	–	–	3	–	–	–	3
Little Missouri River	–	–	–	–	–	–	–
Antelope Creek	–	1	1	–	–	2	4
Dry Fork Cheyenne River	–	–	–	–	–	–	–
Upper Cheyenne River	–	1	1	–	–	–	2
Lightning Creek	–	–	–	–	–	–	–
Upper Belle Fourche River	–	–	1	–	–	5	6
Middle North Platte River	–	–	–	–	–	–	–
Total	1	3	17	0	0	40	61

Source: BLM 2001e

The compressor sites would be constructed in steps. After all necessary permits have been obtained, an access road would be constructed from an existing road to the site. Vegetation would be cleared and topsoil would be stripped and stockpiled. An area of about 2 acres (for booster stations) or 5 acres (for reciprocating stations) would be graded using standard cut-and-fill construction techniques and machinery (bulldozer or grader). Concurrent with construction of the compressors, gas pipelines would be built to the site. In addition, clear lamp lights (250 watts each) would be installed to light each compressor facility. Each light would be mounted on a pole or building and directed downward to illuminate key areas within the facility while minimizing the amount of light projected outside the facility.

The Companies currently propose to use natural gas-fired compressors at all locations. As the Project Area matures, the use of natural gas-fired compressors may diminish and selected units may be constructed with electric-powered compressors. Because the likelihood and extent of this replacement are unknown, the impact analysis documented for Alternative 1 in this EIS assumed that all compressors would be fired by natural gas. All compression internal combustion engines, any dehydration units, and any other emission sources must be permitted with WDEQ's Air Quality Division.

Glycol dehydration units also would be installed at each reciprocating compressor site. The dehydration units would be used to reduce the water in the gas stream to acceptable levels for commercial transportation. The units would have a design flow rate that would accommodate the compression capacity of the station.

High-pressure gas delivery pipelines that connect reciprocating compressor stations with existing and new transmission pipelines would be located along existing roads wherever possible. Disturbance related to these delivery lines is expected to be confined to areas not wider than 100 feet, located within rights-of-way that are already established, wherever possible.

A variety of high-pressure gas pipelines currently serves the PRB (Table 2–15). Separately and in combination, these high-pressure systems deliver gas into other high-pressure pipeline systems that are part of the natural gas grid in the U.S. These downstream facilities are classified as "interstate pipelines." The interstate pipeline companies currently receiving gas from the pipelines identified in Table 2–15 are Williston Basin Interstate, Wyoming Interstate Company, Ltd., KM Interstate Pipeline Company, and Colorado Interstate Gas Company.

Although Thunder Creek Gas Gathering Company, L.L.P., has not announced any expansion, prior statements by the company suggest the Thunder Creek system could be expanded to a capacity of at least 700,000 million cubic feet (mmcf) per day.

The four interstate pipeline companies or other interstate pipeline companies may seek to expand their systems as the ability to deliver CBM gas from the PRB grows. The expansion of any interstate pipelines would be subject to approval by the Federal Energy Regulatory Commission (FERC). FERC's rules and procedures require extensive environmental review as part of the certification process for any new interstate facilities. FERC can condition its approval of new interstate projects with environmental mitigation practices as are indicated necessary by the review of the individual project.

Table 2–15 Summary of High-pressure Pipelines Currently Operating in the Powder River Basin

Pipeline	Capacity (thousand cubic feet per day)
Fort Union Gas Gathering Company, L.L.P	634,000
Thunder Creek Gas Gathering Company, L.L.P	450,000
Big Horn Gathering Company, L.L.P.	450,000
Bittercreek Gathering Company	0
MIGC, Inc.	130,000
KMGGC, Inc.	140,000
Total	1,804,000

Workforce Requirements

Most of the active workforce assigned to develop the Proposed Action would be involved in construction-related activities. Only minimal personnel would be required to operate the field after roads and well pads are constructed, pipelines and utility lines are installed, and wells are drilled and completed. Table 2–16 shows the estimated employment requirements for construction, operation, and reclamation of the project under the Proposed Action.

Construction Resource Requirements

Construction of the project would require a variety of materials and equipment. The primary materials would be water, sand, and gravel. Additionally, small amounts of chemicals would be required. Machinery needed for construction would include heavy equipment (bulldozers, graders, track hoes, trenchers, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, pipelines, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct the Proposed Action is expected to be 6,963 acre-feet (Table 2–17). This water would be obtained from local sources.

Production and Maintenance

Roads

Routine maintenance in the Project Area would occur on a year-round basis or as ground and site conditions permit. This maintenance program includes postponing travel on the two-track roads during and immediately after wet weather when vehicular traffic could cause rutting. Summer (late spring to early fall) road maintenance could include the addition of gravel and blading improved roads consistent with "traveled road maintenance operations" in the area. Other routine maintenance could include grading the borrow ditches and cleaning out culverts and low-water crossings. Noxious weeds also would require yearly control along roads. Winter (late fall to early spring) maintenance would include blading snow from access roads and some summer-like maintenance when necessary and permitted by weather conditions. The Companies would not routinely employ dust abatement procedures on roads within the Project Area during production and maintenance.

Table 2–16 Estimated CBM Employment Requirements for Alternative 1

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	1,217	14
Infiltration Facilities	24 days/impoundment	1,301	72
Containment Impoundment	90 days/impoundment	57	12
Land Application Disposal	20 days/facility	28	4
Injection Well	6.5 days/well	323	5
Total			505
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			-
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	1,217	71
Infiltration Facilities	25 days/facility/year	1,301	75
Containment Impoundment	25 days/facility/year	57	3
Land Application Disposal	12 days/facility/year	28	8
Injection Well	25 days/well/year	323	19
Total			1,918
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	1,217	4
Infiltration Facilities	10 days/facility	1,301	23
Containment Impoundment	45 days/facility	57	5
Land Application Disposal	2 days/facility	578	2
Injection Well	2 days/well	323	1
Total			189

Note:

1. Estimates assume 300 working days per year.

Table 2–17 Summary of Requirements for Sand, Gravel, and Water under Alternative 1

Facility	Amount	Unit	Rate	Total Volume
Sand and Gravel				
Improved roads	7,136	miles	1,173 yd^3/mile	8,370,528
CMFs	394	CMFs	30 yd^3/CMF	11,820
Compressors	245	stations	1,100 yd^3/station	269,500
Total (yd^3)				8,651,848
Water				
Roads	17,755	miles	0.1 acre-feet/mile	1,776
Pipelines	1,408	miles	0.04 acre-feet/mile	56
Well drilling	39,367	wells	0.08 acre-feet/well	3,149
Well completion	39,367	wells	0.05 acre-feet/well	1,968
Compressors	1,358	Compressor	0.01 acre-feet/compressor	14
Total (acre-feet)				6,963

The counties and Companies would have primary responsibility for maintaining the project's improved roads in the Project Area. The counties would continue to maintain existing county roads. The Companies would maintain all other project roads.

When the project is complete, all roads constructed specifically for the project would be removed and reclaimed unless the landowner or county specifically requests that a road be retained. If a landowner decides to keep a road, then the landowner would accept responsibility for maintaining it after it was abandoned by the Companies. The counties would continue to maintain existing county roads and any roads covered by maintenance agreements with BLM.

Wells

Routine Maintenance A maintenance person (a "pumper") may visit each well up to once per day to ensure that the equipment is functioning properly. Automated well monitoring equipment already in operation allows the pumper to visit less frequently, depending on well location, reliability, and other factors. Field personnel would routinely calculate balances between wells and collection and transfer points to ensure that the volumes match within acceptable tolerances. Significant leaks in gas or water pipelines would cause a loss of pressure that would be detectable by the static pressure on the meter run. If a leak is detected, a well would be shut in. The shut-in point would be identified for each well based on individual operating conditions. Field leaks would then be pinpointed using pressures measured in the field, and the problem would be corrected. Maintenance of the various mechanical components of the gas production would occur at intervals recommended by manufacturers or as needed based on site visits.

Additional remote (off-site) computerized monitoring system may be installed if warranted by the number of total producing wells and cost effectiveness. If it is installed, the automated monitoring system would allow remote monitoring of operations at each well. The system would monitor various operating conditions (such as gas and water production rates, pipeline pressure, and separator pressure) to evaluate whether abnormal conditions exist. Electrical cables laid to the wells would provide power to the automation equipment. The operating conditions at the well site would be transmitted via radio to a local, central facility. Maintenance personnel would be immediately dispatched to the well site if a problem is identified. The radio-controlled system would allow real-time signals and solutions in response to well production problems. Control and monitoring of well production by radio telemetry would reduce regular site inspections of each well and would limit vehicular traffic to approximately once a week to each well. However, other factors, such as the need for visual inspection of gas and water pipelines, may require daily visits for safety and environmental reasons.

Workovers   Periodically, a workover on a well would be required. A workover uses a truck-mounted unit similar to a completion rig to ensure that the well is maintained in good condition and is capable of extracting natural gas as efficiently as possible. Workovers are typically needed within the first few months after initial completion to remove coal fines from pumps. Workovers can include repairs to the well bore equipment (casing, tubing, rods, or pumps), the wellhead, or the production formation. These workovers may require venting pressure. Routine repairs would occur only during daylight hours and are usually completed within 1 day. Several days may be required to complete a workover in some limited situations. Although the frequency of workovers cannot be predicted because the requirements vary from well to well, each new well would likely require a workover during the first year of production.

Pipelines

Gas-gathering and produced water pipelines would be routinely inspected along with other facilities. Procedures would be incorporated with inspection of meters at the well sites. If pressure losses are detected, the wells would be shut in until the problem is isolated and addressed.

Electrical Utilities

Routine inspection and maintenance of electric utilities would be done by the utility provider.

Decommissioning and Reclamation

Dry holes would be reclaimed following the procedures described below, except that reclamation would begin as soon as possible after the decision is made that the well would not produce or that it is depleted of gas. The following sections describe the overall procedures the Companies would follow to reclaim the disturbance to as near as possible to pre-development conditions.

Roads

At a minimum, access roads would be reclaimed by ripping or plowing and drill seeding unless the landowner or land manager wishes to make use of any roads and accepts responsibility through execution of a release for future maintenance. Improved roads that are not needed for further use would be blocked, recontoured, reclaimed, and vegetated consistent with the requirements of the federal land managers (according to Onshore Oil and Gas Order No. 1, Approval of Operations) and the State of Wyoming. On private lands, the Companies would execute release of the road to the landowner or reclaim it according to the terms of surface use agreements that may be in effect at that time.

All road disturbances on federal lands would be reseeded with a seed mixture approved by the Authorized Officer, as described in the APD Surface Use Program or COAs. The seed mixture would be planted in the amounts specified in pounds of pure live seed per acre. All seed would be certified as weed free. Seed would be tested in accordance with state laws and within 12 months before purchase. Commercial seed either would be certified or registered. Seeding and planting would be repeated until satisfactory revegetation is achieved. Multi-year control of noxious weeds may be needed on some reclaimed areas.

Wells

All surface facilities would be removed. Depleted production holes would be plugged and abandoned in accordance with Onshore Oil and Gas Order No. 2 and WOGCC's rules. Once the well is conditioned as a static column, the well would be decommissioned by pouring redundant plugs, a slurry of cement and water, at strategic locations in the well bore. These locations would be based on each well's configuration, but would be placed to prevent migration of fluids or gas up the well bore or any uncemented paths. A mixture of bentonite and water would be placed between the cement plugs. Well pads would be recontoured, plowed, and seeded consistent with the procedures described in the APD Surface Use Program or COAs. The Companies also may assign wells to the landowner consistent with the terms of the surface use agreement. When the well is assigned, all rights and responsibilities, including reclamation, pass to the landowner, unless otherwise specified. The landowner must then properly permit the well for beneficial uses after CBM production has ceased according to WSEO's procedures and policies.

Pipelines

The procedures for decommissioning and reclaiming pipelines are straightforward. The underground pipelines would be cleaned, disconnected, and then abandoned in place to avoid any unnecessary surface disturbance, as noted in the COAs for the APD or the POD for the ROW or SUP. Any surface disturbances associated with the underground pipelines are addressed in previous sections.

Electrical Utilities

Underground electric lines would be disconnected and abandoned in place to avoid any unnecessary surface disturbance. Aboveground lines would be disconnected and the power poles would be removed from the sites. Surface disturbance associated with the removal would be reclaimed according to the COAs for the APD or the POD for the ROW or SUP.

Non-CBM Development

BLM has evaluated the potential for non-CBM oil and gas resources to occur and be developed in the Project Area. In part, this evaluation resulted in the mapping of various levels of potential (such as very low, low, moderate, or high) within the Buffalo Field Office Area (BFOA). It also resulted in three levels of potential development, which are documented in BLM's RFD Scenario for the Buffalo Field Office (BLM 2001f).

The moderate level of development under BLM's RFD Scenario, which is the basis for this alternative, projects that about 3,200 non-CBM wells will be drilled and completed within the Project Area over the 10-year period. As shown on Table 2–18, 3,000 of these wells would be drilled in the portion of the Project Area that is under the jurisdiction of the Buffalo Field Office (BFO) and FS. The remaining 200 wells would be drilled in the portion of the Project Area under the jurisdiction of the Casper Field Office (CFO).

Table 2–18 Projected Distribution of Non-CBM Wells Under Alternative 1

	Potential for Oil and Gas				
Sub-watershed	Very Low	Low	Moderate	High	Total
Buffalo Field Office Area and TBNG					
Little Bighorn River	5	0	0	0	5
Upper Tongue River	8	36	0	0	44
Middle Fork Powder River	20	4	0	0	24
North Fork Powder River	1	0	0	0	1
Upper Powder River	0	20	377	0	397
South Fork Powder River	3	0	0	0	3
Salt Creek	0	5	13	0	18
Crazy Woman Creek	3	11	2	0	16
Clear Creek	0	28	0	0	28
Middle Powder River	0	6	71	37	114
Little Powder River	0	0	166	1,368	1,534
Little Missouri River	0	0	2	92	94
Antelope Creek	0	0	67	0	67
Upper Cheyenne River	0	7	39	0	46
Upper Belle Fourche River	0	3	213	393	609
Total	40	120	950	1,890	3,000
Casper Field Office Area					
Converse County					200
Total					3,200

Surface disturbance for a typical oil well (from 5,000 to 12,000 feet deep) includes 2.25 acres for the well pad and 0.5 acres for a ⅓-mile long bladed road, for a total of 2.75 acres disturbed for drilling operations. Part of the well pad area is reclaimed as production operations begin. The entire area of disturbance is reclaimed when the well is plugged and abandoned.

As shown on Table 2–19, about 8,800 surface acres of the Project Area may be disturbed by the construction of non-CBM wells. Most of this disturbance would occur in three sub-watersheds. They are Little Powder River, Upper Belle Fourche River, and Upper Powder River. Once the wells are operational and partial reclamation has occurred, long-term disturbance would encompass about 82 percent of the original disturbance.

Table 2–19 Projected Maximum Disturbance Caused by Non-CBM Wells Under Alternative 1

	Areal Extent of Disturbance	
Sub-watershed	Short term (acres)	Long term (acres)
Buffalo Field Office Area and TBNG		
Little Bighorn River	14	12
Upper Tongue River	121	103
Middle Fork Powder River	66	56
North Fork Powder River	3	2
Upper Powder River	1,092	933
South Fork Powder River	8	7
Salt Creek	50	42
Crazy Woman Creek	44	38
Clear Creek	77	66
Middle Powder River	314	268
Little Powder River	4,219	3,605
Little Missouri River	259	221
Antelope Creek	184	157
Upper Cheyenne River	127	108
Upper Belle Fourche River	1,675	1,431
Total	8,250	7,050
Casper Field Office Area		
Converse County	550	470
Total	8,800	7,520

Note:
Maximum disturbance is based on 2.75 acres per well for short-term disturbances and 2.0 acres per well for long-term disturbances.

The non-CBM development also would require a workforce involved in construction-related activities. After roads and well pads are constructed and wells are drilled and completed, minimal personnel would be required to operate the field. Table 2–20 shows the estimated employment requirements for the non-CBM wells.

Safety/Emergency Response

This section outlines the methods that the Companies would employ to ensure the safe operation of the oil and gas wells during development and production. It also describes how the Companies would respond to emergencies. In cooperation with the WOGCC and Wyoming Occupational Safety and Health Administration, the Companies have undertaken a comprehensive study of safety regulations currently in place related to the development and will recommend to the agencies of jurisdiction any changes deemed necessary to protect the health and safety of the public as well as those employed in the development.

Geologic Hazards

During drilling operations, abnormally high formation pressure could be encountered, which could result in an uncontrolled well condition. However, more than 6,000 CBM wells have been drilled in the Project Area with no instances of abnormally high pressure. Blowouts are considered highly unlikely because of the shallow depths of the wells, normal and below-normal pressures in the formations, and experience in the Project Area. WOGCC and BLM require diverters after the surface casing has been set.

Table 2–20 Estimated Non-CBM Employment Requirements for Alternative 1

Work Category	Time Requirements per Unit	Number of Units	Average Number of Workers per Day
Construction and Installation			
Access Roads	0.5 day/mile	3,200	1
Well Pads	1 day/pad	3,200	1
Drilling and Casing	4 days/well	3,200	27
Well Completion	2 days/well	3,200	13
Total			42
Operation and Maintenance			
Road/Pad Maintenance	1 days/well	1,600	6
Pumpers			0
Wells	15 days/well/year	1,600	8
General Infrastructure	12 days/well/year	1,600	6
Office	6 days/well	1,600	3
Well Workover	4 days/well	1,600	2
Total			25
Decommissioning/Reclamation			
Wells	2 days/well	1,600	21
Roads	2 days/mile	1,600	2
Total			23

Fires and Explosions

The potential for leaks or ruptures in gas flowlines or pipelines would exist. Most ruptures are the result of heavy equipment that accidentally strikes the pipeline while it is operating nearby. These ruptures could result in an explosion and fire if a spark or open flame ignites the escaping gas. The materials used in the pipelines would be designed and selected according to applicable standards to minimize the potential for a leak or rupture. Frequent markers along the pipelines would reduce the risk of accidental ruptures from excavating equipment. Additionally, the Companies would monitor the flow in the pipeline by either remote sensors or daily inspections of the flow meters, which would reduce the probability of ruptures through prompt detection of leaks.

Well fires are rare, but could occur under certain conditions. For the reasons listed in the previous sections, the probability of a blowout is very low. The Companies would include procedures for reporting and controlling fires in the emergency response programs. The Companies have and would continue to conduct cooperative training exercises with the fire and rescue departments within the Project Area.

Public Safety

The Companies would take measures to protect the public from hazards at wells. Warning signs would be posted around facilities, as necessary. In addition, compressor stations would be fenced and gated.

Employee Safety

The Companies would develop Emergency Plans that would cover all potential emergencies, including fires, employee injuries, and chemical releases, among others. The plans would include telephone numbers for all medical and emergency services and the contacts in event of emergencies. In addition, the Companies would not allow employees and contractors to bring firearms into the area. The plans would be posted at all the Companies' local offices and field facilities. All employees and subcontractors would be trained on the Emergency Plan when they are hired and refresher courses would be presented annually.

Water Monitoring and Mitigation

Monitoring and mitigation for both groundwater and surface water are a substantial part of the Proposed Action. The Companies are conducting, and propose to continue to conduct, hydrologic monitoring to obtain information that would enable them to detect impacts on other water users and to control activities and operations to assure regulatory compliance and public protection.

Mitigation measures include establishment of monitoring wells and stream gauges. The Companies work with the surface owners to establish water controls, diversions, and uses for the surface discharges. Treatment, injection, and storage may be used where necessary and practicable.

Groundwater

Under the current groundwater monitoring approach supported by the Wyodak EIS and previous CBM planning documents, BLM is requiring the installation and operation of approximately two pairs of monitor wells per township throughout the CBM probable development area. BLM proposes to modify this approach to require the drilling of a reduced number (approximately 35) of strategically located, somewhat more complex (more wells per location) locations in the next two years. The goal is to complete these wells as far ahead of development as possible. By concentrating data collection efforts at a reduced number of more comprehensive locations, more complete site-specific and inter-aquifer information can be collected and still have adequate coverage throughout the basin for a regional analysis. In addition, we will end up with better baseline data by having most of the wells drilled prior to development.

All operators on federal minerals are required to offer a Water Well Agreement as set forth in the Gillette South EIS and the Wyodak EIS. This agreement protects nearby water wells permitted by WSEO. The Companies generally offer the same agreement when they are drilling on fee and state lands.

Surface Water

The Companies are required to monitor and report produced water volumes and quality to WDEQ pursuant to the requirements of the NPDES permit. Discharges are required to meet all applicable WDEQ water quality standards and regulations at all times. The Companies also must report produced water volumes to the WOGCC and WSEO.

The BLM water management plans, FS, and WDEQ require the Companies to use BMPs that would prevent erosion and damage to agricultural activities.

Surface gauging stations may be needed on the Little Powder, Powder, Belle Fourche, Cheyenne, and Tongue Rivers. The cost of this monitoring would be shared among BLM, the U.S. Department of the Interior, Geological Survey (USGS), and the Companies.

BLM would periodically monitor water quality by sampling at discharge points and on streams. BLM also would monitor selected stream channels that receive CBM discharged water for signs of accelerated erosion and degradation.

In August 2001, the States of Montana and Wyoming signed an Interim MOC to document their commitments and intent to protect and maintain water quality in the PRB within Montana during an 18-month interim period (Appendix B). At the conclusion of this interim period, the states will negotiate a final MOC that will include recognition of protective water quality standards and allocation of any assimilative capacity. A monitoring program to implement the interim MOC and to assist in development of a final MOC is part of the agreement. Currently, the states are developing this monitoring program. Once it has been developed, the aspects of the monitoring plan that are applicable to the oil and gas development addressed in this EIS would be incorporated into the ROD.

Alternative 2 — Proposed Action with Reduced Emission Levels and Expanded Produced Water Handling Scenarios

Alternative 2 was developed specifically to respond to four of the 18 key issues. They are the issues addressing effects of the Proposed Action on aquifers (Issue 1), the quantity and quality of surface waters (Issues 2 and 3), and effects on air quality and visibility (Issue 6). BLM and FS altered the Proposed Action in two primary areas to respond to these issues: handling of produced water and compression of gas. Other than the differences described below, Alternative 2 is the same as the Proposed Action.

Methods for Handling Produced Water

The overall methods for handling the disposal of produced water are the same as were included in the Proposed Action. However, BLM and FS have altered the distribution of produced water among the methods to emphasize handling in two ways: infiltration and treatment. As shown on Table 2–21, Alternative 2A emphasizes use of infiltration impoundments to dispose of CMB produced water. In contrast, Alternative 2B emphasizes the use of passive and active treatment to dispose of CBM produced water (Table 2–22). The emphasis of these alternatives was developed in response to WDEQ's projections for how CBM produced water probably would be handled in the future to meet the MOC between Montana and Wyoming on Interim Water Quality Criteria (Appendix B).

The changes in methods of water handling included as part of Alternatives 2A and 2B slightly alter the number of acres that would be disturbed. Instead of affecting 193,589 acres of short-term disturbance as under Alternative 1, Alternative 2A would affect 202,843 acres over the short term (Table 2–23). Long-term disturbance associated with Alternative 2A also would be slightly less, at

95,138 acres (Table 2–24). In contrast, Alternative 2B would affect 199,233 acres over the short term (Table 2–25) and 91,528 acres over the long term (Table 2–26).

Table 2–21 Assumed Water Handling Methods for CBM Wells with an Infiltration Emphasis — Alternative 2A

	Water Handling Method[1,2,3]						
	NPDES-permitted Discharge						
Sub-watershed	Untreated Discharge (percent)	Passive Treatment (percent)	Active Treatment (percent)	Infiltration Impoundment (percent)	Containment Impoundment (percent)	LAD (percent)	Injection (percent)
Upper Tongue River	0	5	0	65	5	15	10
Upper Powder River	0	30	0	60	0	5	5
Salt Creek	0	0	0	70	5	5	20
Crazy Woman Creek	0	5	0	70	5	10	10
Clear Creek	0	5	0	70	5	10	10
Middle Powder River	0	30	0	55	0	10	5
Little Powder River	0	40	0	45	0	10	5
Antelope Creek	0	60	0	30	0	5	5
Upper Cheyenne River	0	60	0	30	0	5	5
Upper Belle Fourche River	30	30	0	30	0	5	5

Notes:

1. The percentages shown represent the distribution of water handling methods assumed for the analysis, not the amount of water that actually reaches the river.
2. Handling Methods:
   NPDES-permitted Discharge – includes methods of handling the produced water that require an NPDES permit.
   Untreated discharge – water that is discharged onto the surface of the ground without any treatment.
   Passive treatment – water that is amended through passive methods to meet standards before discharge. An example of this method is passing the water over scoria to remove iron.
   Active treatment – water that is amended through active methods to meet standards before discharge. An example of this method is passing the water through a reverse osmosis system.
   Infiltration impoundment – water contained in upland and bottomland impoundments allowing for infiltration and groundwater recharge. Infiltration impoundments constructed in-channel may allow for overflow under given storm events.
   Containment impoundment – includes upland impoundments, lined, with minimal infiltration and no direct surface discharge or lateral subsurface movement of water and down-gradient expression in seeps or springs. These impoundments are permitted by WOGCC.
   LAD = land application disposal. Typically, land application is achieved by spraying produced water through agricultural irrigation equipment and high-pressure atomizers.
   Injection – represents that water that is injected into disposal wells.
3. The above percentages are not upper thresholds that can or will be enforced. They are merely a disclosure of effects of one of many various ways water may be handled to meet the Wyoming water quality standards and agreement with bordering states.

Compression

This alternative includes two options for compression of the CBM, both of which were analyzed in detail. The first option is electrification of 50 percent of the booster compressors. Under this option, half of the new 1,060 booster compressor units would be electrically powered. The other half would be gas-fired units. The power for the electrical units would be brought to the compressor stations via the same power lines that are included in the Proposed Action. Thus, no new external construction would be required. Except for the exchange of gas-fired booster units for electrical booster units, no other visible changes would occur. Reciprocating compressors would remain the same.

Table 2–22 Assumed Water Handling Methods for CBM Wells with a Treatment Emphasis — Alternative 2B

	Water Handling Method[1,2,3]						
	NPDES-permitted Discharge						
Sub-watershed	Untreated Discharge (percent)	Passive Treatment (percent)	Active Treatment (percent)	Infiltration Impoundment (percent)	Containment Impoundment (percent)	LAD (percent)	Injection (percent)
Upper Tongue River	0	5	20	45	5	15	10
Upper Powder River	0	30	15	40	5	5	5
Salt Creek	0	0	15	50	10	5	20
Crazy Woman Creek	0	5	20	45	5	15	10
Clear Creek	0	5	20	50	5	10	10
Middle Powder River	0	30	10	40	5	10	5
Little Powder River	0	40	20	25	0	10	5
Antelope Creek	0	60	10	25	0	5	0
Upper Cheyenne River	0	60	10	25	0	5	0
Upper Belle Fourche River	30	30	0	30	0	5	5

Notes:
1. The percentages shown represent the distribution of water handling methods assumed for the analysis, not the amount of water that actually reaches the river.
2. Handling Methods:
   NPDES-permitted Discharge – includes methods of handling the produced water that require an NPDES permit.
   Untreated discharge – water that is discharged onto the surface of the ground without any treatment.
   Passive treatment – water that is amended through passive methods to meet standards before discharge. An example of this method is passing the water over scoria to remove iron.
   Active treatment – water that is amended through active methods to meet standards before discharge. An example of this method is passing the water through a reverse osmosis system.
   Infiltration impoundment – water contained in upland and bottomland impoundments allowing for infiltration and groundwater recharge. Infiltration impoundments constructed in-channel may allow for overflow under given storm events.
   Containment impoundment – includes upland impoundments, lined, with minimal infiltration and no direct surface discharge or lateral subsurface movement of water and down-gradient expression in seeps or springs. These impoundments are permitted by WOGCC.
   LAD = land application disposal. Typically, land application is achieved by spraying produced water through agricultural irrigation equipment and high-pressure atomizers.
   Injection – represents that water that is injected into disposal wells.
3. The above percentages are not upper thresholds that can or will be enforced. They are merely a disclosure of effects of one of many various ways water may be handled to meet Wyoming's water quality standards and agreements with bordering states.

The second option analyzed under this alternative was electrification of all 1,060 new booster compressor units. Under this option, no new gas-fired boosters would be constructed. All would be powered by electricity. As noted above, no new external construction would be required and the reciprocating compressors would continue to be gas-fired units.

Under both of these options, new power generation capacity would be required to provide the electricity needed for the electrical booster and reciprocating compressors. The potential locations and sizes of the facilities that could be constructed to provide the necessary additional capacity are too numerous and speculative to evaluate in this analysis.

As a result of the changes in water handling for Alternatives 2A and 2B relative to Alternative 1, additional employees would be needed to construct, operate, maintain, decommission, and reclaim the facilities. Table 2–27 and Table 2–28 summarize the estimated employment requirements for Alternatives 2A and 2B.

Table 2–23 Summary of Estimated Short-term CBM Disturbance Associated with Alternative 2A

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	631	59	1,542	520	2,075	782	3,133	248	727	782	10	12	10,521
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	4,978	435	11,635	3,639	14,529	5,458	17,165	2,408	6,327	5,458	175	232	72,439
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	11	1	234	88	350	132	46	24	121	132	5	4	1,148
Crazy Woman Creek	773	67	2,374	824	3,288	1,234	3,460	364	1,187	1,234	25	24	14,854
Clear Creek	1,010	86	2,363	908	3,623	1,362	4,447	320	778	1,362	10	18	16,287
Middle Powder River	238	22	682	188	752	283	891	206	267	283	5	6	3,823
Little Powder River	534	47	2,548	1,058	4,222	1,586	1,730	327	485	1,586	15	12	14,150
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	474	38	7,703	3,683	14,694	5,524	1,093	191	417	5,524	20	14	39,375
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	160	12	812	166	662	249	354	291	455	249	10	6	3,426
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	1,664	136	4,701	1,798	7,176	2,702	3,944	473	1,455	2,702	30	40	26,820
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	10,474	903	34,593	12,871	51,372	19,312	36,263	4,852	12,217	19,312	305	368	202,843

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–21.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–24 Summary of Estimated Long-term CBM Disturbance Associated with Alternative 2A

			Roads		Poly Pipeline			Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Water Handling Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	259	24	1,542	520	0	0	3,133	0	0	261	10	12	5,760
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,897	174	11,635	3,639	0	0	17,165	0	0	1,819	175	232	36,736
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	0	234	88	0	0	46	0	0	44	5	4	424
Crazy Woman Creek	292	27	2,374	824	0	0	3,460	0	0	411	25	24	7,437
Clear Creek	376	35	2,363	908	0	0	4,447	0	0	454	10	18	8,610
Middle Powder River	96	9	682	188	0	0	891	0	0	94	5	6	1,971
Little Powder River	204	19	2,548	1,058	0	0	1,730	0	0	529	15	12	6,114
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	164	15	7,703	3,683	0	0	1,093	0	0	1,841	20	14	14,534
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	53	5	812	166	0	0	354	0	0	83	10	6	1,490
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	593	55	4,701	1,798	0	0	3,944	0	0	901	30	40	12,061
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	3,937	363	34,593	12,871	0	0	36,263	0	0	6,437	305	368	95,138

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2-21.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions

Source: BLM 2001e

Table 2–25 Summary of Estimated Short-term CBM Disturbance Associated with Alternative 2B

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	631	59	1,542	520	2,075	782	2,718	248	727	782	10	12	10,106
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	4,978	435	11,635	3,639	14,529	5,458	15,553	2,408	6,327	5,458	175	232	70,827
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	11	1	234	88	350	132	43	24	121	132	5	4	1,145
Crazy Woman Creek	773	67	2,374	824	3,288	1,234	3,066	364	1,187	1,234	25	24	14,460
Clear Creek	1,010	86	2,363	908	3,623	1,362	3,847	320	778	1,362	10	18	15,687
Middle Powder River	238	22	682	188	752	283	848	206	267	283	5	6	3,780
Little Powder River	534	47	2,548	1,058	4,222	1,586	1,404	327	485	1,586	15	12	13,824
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	474	38	7,703	3,683	14,694	5,524	929	191	417	5,524	20	14	39,211
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	160	12	812	166	662	249	301	291	455	249	10	6	3,373
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	1,664	136	4,701	1,798	7,176	2,702	3,944	473	1,455	2,702	30	40	26,820
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	10,474	903	35,593	12,871	51,372	19,312	32,653	4,852	12,217	19,312	305	368	199,233

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–22.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–26 Summary of Estimated Long-term CBM Disturbance Associated with Alternative 2B

Sub-watershed	Well Pads (acres)	CMFs (acres)	Roads: Improved (acres)	Roads: Two-track (acres)	Poly Pipeline: 2–3-inch (acres)	Poly Pipeline: 12-inch (acres)	Water Handling Facilities[1] (acres)	Compressor Discharge Pipelines: Recip.[2] (acres)	Compressor Discharge Pipelines: Booster[3] (acres)	Power Line: Overhead (acres)	Compressor Stations: Recip. (acres)	Compressor Stations: Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	259	24	1,542	520	0	0	2,718	0	0	261	10	12	5,345
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,897	174	11,635	3,639	0	0	15,553	0	0	1,819	175	232	35,124
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	0	234	88	0	0	43	0	0	44	5	4	421
Crazy Woman Creek	292	27	2,374	824	0	0	3,066	0	0	411	25	24	7,043
Clear Creek	376	35	2,363	908	0	0	3,847	0	0	454	10	18	8,010
Middle Powder River	96	9	682	188	0	0	848	0	0	94	5	6	1,929
Little Powder River	204	19	2,548	1,058	0	0	1,404	0	0	529	15	12	5,788
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	164	15	7,703	3,683	0	0	929	0	0	1,841	20	14	14,370
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	53	5	812	166	0	0	301	0	0	83	10	6	1,437
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	593	55	4,701	1,798	0	0	3,944	0	0	901	30	40	12,061
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	3,938	363	34,593	12,871	0	0	32,653	0	0	6,437	305	368	91,528

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–22.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions

Source: BLM 2001e

Table 2–27 Estimated CBM Employment Requirements for Alternative 2A

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	606	7
Infiltration Facilities	24 days/impoundment	3,091	172
Containment Impoundment	90 days/impoundment	12	3
Land Application Disposal	20 days/facility	68	10
Injection Well	6.5 days/well	305	5
Total			595
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			0
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	606	35
Infiltration Facilities	25 days/facility/year	3,091	179
Containment Impoundment	25 days/facility/year	12	1
Land Application Disposal	12 days/facility/year	68	19
Injection Well	25 days/well/year	305	16
Total			2,191
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	606	2
Infiltration Facilities	10 days/facility	3,091	55
Containment Impoundment	45 days/facility	12	1
Land Application Disposal	2 days/facility	68	1
Injection Well	2 days/well	305	1
Total			214

Note:

1. Estimates assume 300 working days per year.

Table 2–28 Estimated CBM Employment Requirements for Alternative 2B

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	878	10
Infiltration Facilities	24 days/impoundment	2,169	121
Containment Impoundment	90 days/impoundment	37	8
Land Application Disposal	20 days/facility	72	11
Injection Well	6.5 days/well	292	4
Total			552
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			0
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	878	51
Infiltration Facilities	25 days/facility/year	2,169	126
Containment Impoundment	25 days/facility/year	37	2
Land Application Disposal	12 days/facility/year	72	20
Injection Well	25 days/well/year	292	17
Total			2,157
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	878	3
Infiltration Facilities	10 days/facility	2,169	34
Containment Impoundment	45 days/facility	37	3
Land Application Disposal	2 days/facility	72	1
Injection Well	2 days/well	292	1
Total			196

Note:

1. Estimates assume 300 working days per year.

Alternative 3 — No Action

The No Action alternative is required by NEPA for comparison with the other alternatives analyzed in the EIS. For this analysis, the No Action alternative would not authorize additional natural gas development on federal leases within the Project Area. Drilling could continue on state and private leases. BLM and the FS assumed the pattern of spacing for CBM wells on state and private leases would remain at 80 acres. Access and pipelines across federal lands to reach the proposed state and fee wells would be granted as required by BLM's policy.

The Department of Interior's authority to implement a "No Action" alternative that precludes development by denying the process is, however, limited. An oil and gas lease grants the lessee the "right and privilege to drill for, mine, extract, remove, and dispose of all oil and gas deposits" in the lease lands, "subject to the terms and conditions incorporated in the lease" (Form 3110–2). Because the Secretary of Interior has the authority and responsibility to protect the environment within federal oil and gas leases, restrictions are imposed on the terms of the lease.

Leases within the project area contain various stipulations that address surface disturbance, surface occupancy, limited surface use and restrictions on timing. In addition, the lease stipulations provide for the imposition of conditions that the BLM and/or FS may require to protect the surface/subsurface of the leased lands and the environment. Approval of an APD could only be denied when the activity would constitute a violation of law or regulation or would cause unacceptable impacts (43 U.S.C. 1732(b); 30 U.S.C. 226(g); 43 CFR 3101.1-2).

Development of Coal Bed Methane

Under this alternative, development of non-federal CBM would continue to occur on non-federal minerals. The agencies assumed that development of fee and state minerals would occur along the same overall schedule as for Alternative 1.

As a result, the Companies would drill 15,504 new CBM wells between 2002 and 2011 (Table 2–29). These wells would be in addition to the 12,024 CBM wells already permitted or drilled on federal, state, and private lands. Thus, 27,528 CBM wells would be developed under this alternative by 2011 (Table 2–29).

As under Alternatives 1 and 2, some of the new CBM wells would be drilled from the same well pads. Thus, the number of pads constructed would be less than the number of wells drilled. The Companies would construct 10,572 new well pads between 2002 and 2011 (Table 2–30). With the 9,595 pads constructed or permitted for construction before 2002, this alternative would result in 20,167 well pads by 2011 (Table 2–30).

Because fewer new wells would be drilled and pads constructed, the number of facilities constructed also would be smaller than under the Proposed Action (Table 2–31). Furthermore, the overall short-term and long-term disturbances associated with this alternative would be less than would occur with implementation of Alternatives 1 or 2 (Table 2–32 and Table 2–33).

Table 2–29 Distribution of CBM Wells by Sub-watershed — Alternative 3

Sub-watershed	Number of CBM Wells		
	Pre-2002	2002–2011	Total
Little Bighorn River	0	0	0
Upper Tongue River	819	2,164	2,983
Middle Fork Powder River	0	0	0
North Fork Powder River	0	0	0
Upper Powder River	2,808	4,445	7,253
South Fork Powder River	0	0	0
Salt Creek	0	19	19
Crazy Woman Creek	150	949	1,099
Clear Creek	389	2,502	2,891
Middle Powder River	727	201	928
Little Powder River	1,814	964	2,778
Little Missouri River	0	0	0
Antelope Creek	251	604	855
Dry Fork Cheyenne River	0	0	0
Upper Cheyenne River	401	256	657
Lightning Creek	0	0	0
Upper Belle Fourche River	4,659	3,400	8,059
Middle North Platte River	6	0	6
Total	12,024	15,504	27,528

Source: BLM 2001e

With fewer wells overall, implementation of this alternative also would result in smaller amounts of produced water and gas. Table 2–34 and Table 2–35 show the amounts of water and gas projected for this alternative. However, it is possible that more wells would result if the companies determined that the federal mineral acreage was economic to drain at 40 acre spacing and the companies could request the WOGCC to down space to 40 acres around federal mineral acreage.

Drilling and Construction of Facilities

Electrical Power Utilities

Based on projected power demands, it is anticipated that the Companies would require 0.5 MW per day to transport 3 bcf of natural gas per day using gas-fired compression. Based on this power demand, the maximum power requirement would be 0.6 MW per day.

Table 2–30 Distribution of CBM Well Pads by Sub-watershed — Alternative 3

	Number of CBM Well Pads		
Sub-watershed	Pre-2002	2002–2011	Total
Little Bighorn River	0	0	0
Upper Tongue River	397	980	1,377
Middle Fork Powder River	0	0	0
North Fork Powder River	0	0	0
Upper Powder River	2,254	2,847	5,101
South Fork Powder River	0	0	0
Salt Creek	0	19	19
Crazy Woman Creek	63	638	701
Clear Creek	231	1,745	1,976
Middle Powder River	438	97	535
Little Powder River	1,301	655	1,956
Little Missouri River	0	0	0
Antelope Creek	249	527	776
Dry Fork Cheyenne River	0	0	0
Upper Cheyenne River	390	256	646
Lightning Creek	0	0	0
Upper Belle Fourche River	4,266	2,808	7,074
Middle North Platte River	6	0	6
Total	9,595	10,572	20,167

Source: BLM 2001e

Under this alternative, three-phase 24.9-kV distribution lines would connect wells and compressor facilities with the existing transmission and distribution system in the Project Area. Electricity would be routed to compressor stations and CMFs above ground on poles generally located along the access roads or on additional rights-of-way (30 feet wide) across open land. Between the CMFs and wells, the secondary electric service power lines (480 volt) would be buried in the same trenches as the pipelines to gather gas and produced water. The installation and power would be provided by the utility company that supplies these services. The power lines would be constructed after access roads have been developed and would coincide with completion of well drilling. The power lines would be designed and constructed according to the Avian Power Line Interaction Committee's (1996) guidelines for the prevention of electrocution of raptors.

The aboveground power lines would be constructed using tracked and wheeled equipment. Holes for the poles would be located so that they do not disturb existing sensitive vegetation and would be excavated to a depth of 6 to 8 feet. Poles and other structural components would be transported to the construction site, where they would be assembled and then erected by a boom truck.

Table 2–31 Summary of New Facilities that Comprise Alternative 3

Sub-watershed	Well[3] Pads	Roads: Improved (miles)	Roads: Two-track (miles)	Poly Pipeline: 2–3-inch (miles)	Poly Pipeline: 12-inch (miles)	Steel Pipeline: 12-inch (miles)	Electrical Line: Overhead (miles)	Recip Compressors[1] (units)	Recip Compressors[1] (horsepower)	Booster Compressors[2] (units)	Booster Compressors[2] (horsepower)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	979	288	369	491	185	80	185	9	14,850	31	10,850
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	2,847	558	722	961	361	158	361	48	79,200	150	52,500
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	19	24	37	49	19	5	19	0	0	3	1,050
Crazy Woman Creek	638	157	229	304	114	38	114	6	9,900	24	8,400
Clear Creek	1,746	335	506	673	253	68	253	8	13,200	37	12,950
Middle Powder River	97	16	32	43	16	0	16	0	0	0	0
Little Powder River	655	256	452	601	226	22	226	3	4,950	9	3,150
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	527	564	1,104	1,468	552	10	552	0	0	10	3,500
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	256	74	66	87	33	24	33	2	3,300	4	1,400
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	2,808	592	871	1,159	436	110	436	21	34,650	82	28,700
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0
Total	10,572	2,864	4,387	5,836	2,194	515	2,194	97	160,050	350	122,500

Notes:

1. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
2. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
3. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–32 Summary of Estimated Short-term Disturbance Associated with Alternative 3

Sub-watershed	Well Pads (acres)	CMFs (acres)	Roads: Improved (acres)	Roads: Two-track (acres)	Poly Pipeline: 2–3-inch (acres)	Poly Pipeline: 12-inch (acres)	Water Handling Facilities[1] (acres)	Compressor Discharge Pipelines: Recip.[2] (acres)	Compressor Discharge Pipelines: Booster[3] (acres)	Power Line: Overhead (acres)	Compressor Stations: Recip. (acres)	Compressor Stations: Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	531	50	1,396	448	1,785	672	2,007	248	727	672	10	12	8,559
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,174	102	2,706	875	3,493	1,312	2,462	550	1,364	1,312	40	50	15,440
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	6	0	114	45	180	68	14	0	61	68	0	2	557
Crazy Woman Creek	254	22	763	277	1,106	415	626	73	391	415	5	8	4,354
Clear Creek	675	57	1,623	613	2,446	919	2,351	213	605	919	10	14	10,447
Middle Powder River	50	5	79	39	157	59	145	0	0	59	0	0	593
Little Powder River	259	22	1,240	548	2,186	821	690	109	162	821	5	4	6,866
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	174	14	2,735	1,338	5,337	2,006	431	0	119	2,006	0	4	14,164
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	77	6	358	80	318	120	186	145	152	120	5	2	1,568
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	961	78	2,872	1,055	4,213	1,586	2,771	315	1,018	1,586	20	28	16,504
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	4,159	356	13,886	5,317	21,221	7,980	11,683	1,655	4,598	7,930	95	124	79,052

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–33 Summary of Estimated Long-term Disturbance Associated with Alternative 3

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	216	20	1,396	448	0	0	2,007	0	0	224	10	12	4,333
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	445	41	2,706	875	0	0	2,462	0	0	437	40	50	7,056
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	2	0	114	45	0	0	14	0	0	23	0	2	200
Crazy Woman Creek	95	9	763	277	0	0	626	0	0	138	5	8	1,921
Clear Creek	250	23	1,623	613	0	0	2,351	0	0	306	10	14	5,191
Middle Powder River	20	2	79	39	0	0	145	0	0	20	0	0	305
Little Powder River	96	9	1,240	548	0	0	690	0	0	274	5	4	2,865
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	60	6	2,735	1,338	0	0	431	0	0	669	0	4	5,243
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	26	2	358	80	0	0	186	0	0	40	5	2	699
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	340	31	2,872	1,055	0	0	2,771	0	0	529	20	28	7,646
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	1,551	143	13,886	5,317	0	0	11,683	0	0	2,660	95	124	35,458

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–34 Projected Amount of Water Produced from CBM Wells under Alternative 3

	Water Produced (acre-feet)[1]																
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	10,279	15.847	19.119	20,187	20,393	17.701	17.623	13.310	12,471	12,585	6,950	3,785	2,018	1.032	473	176	173,949
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	45,850	54,608	58,124	60,210	60,054	53,068	42,195	19,954	13,226	9,671	5,170	2,646	1,167	480	215	80	426,718
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	184	104	85	179	259	146	82	43	24	13	5	0	0	0	0	0	1,124
Crazy Woman Creek	4,429	5,971	6,893	7,806	7,664	7,348	6,548	4,452	4,350	4,396	2,418	1,315	687	346	174	64	64,861
Clear Creek	9,172	14,731	17,758	18,176	18,858	17,907	16,772	13,780	13,377	13,941	7,738	4,235	2,265	1,148	556	209	170,623
Middle Powder River	7,284	7,298	7,883	8,634	7,886	5,347	5,181	1,615	961	1,055	574	313	168	81	32	17	54,329
Little Powder River	17,026	18,231	18,119	18,462	16,931	13,217	13,897	3,479	3,679	3,124	1,899	1,132	677	356	186	55	130,470
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	10,536	10,871	10,596	10,803	10,323	9,057	6,433	2,311	1,348	1,074	378	132	45	14	4	1	73,926
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	6,415	6,870	6,486	6,712	6,744	5,213	4,266	870	806	451	159	55	19	6	2	0	45,074
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	47,247	53,736	58,399	61,750	61,591	58,656	52,057	27,701	21,615	17,323	11,694	7,466	4,143	1,836	991	463	486,668
Middle North Platte River	0	0	0	.0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	158,422	188,267	203,462	212,919	210,703	187,660	165,054	87,515	71,857	63,633	36,985	21,079	11,189	5,299	2,633	1,065	1,627,742

Note:

1. Volumes shown include produced water from pre-2002 wells as well as the new CBM wells.

Sources: BLM 2001e and Meyer 2002b.

Table 2–35 Projected Amounts of Natural Gas Produced from CBM Wells under Alternative 3

	Total Cubic Feet of Methane Produced per Day by Year (in mmcf)									
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Little Bighorn River	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	18	30	47	60	70	74	76	77	77	77
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0
Upper Powder River	252	399	481	534	542	538	520	446	308	192
South Fork Powder River	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	6	7	8	8	7	7	6	4	2
Crazy Woman Creek	31	50	63	72	75	75	74	66	51	38
Clear Creek	37	58	76	89	97	101	103	102	97	93
Middle Powder River	2	3	4	5	5	6	6	6	6	6
Little Powder River	26	39	45	49	50	50	51	49	43	38
Little Missouri River	0	0	0	0	0	0	0	0	0	0
Antelope Creek	29	44	50	54	54	53	52	45	33	23
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	15	22	25	27	27	27	27	27	23	20
Lightning Creek	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	161	228	252	264	261	260	257	233	180	132
Middle North Platte River	0	0	0	0	0	0	0	0	0	0
Total	575	879	1,050	1,162	1,189	1,191	1,173	1,057	822	621

Source: BLM 2001e

The locations of the poles could be moved within the 30-foot wide right-of-way (ROW) if topography or impacts to cultural, vegetative, or wildlife resources are identified at the site of the structure. In areas of thick vegetation or where vegetation may impede the performance of the active line, vegetation would be cleared, typically with hand-held equipment. BLM would be consulted before any vegetation is removed where areas of sensitive plant resources are known to occur.

All aboveground electric lines typically would be installed on 35-foot tall poles. Poles would be required approximately every 300 feet. Approximately 2,195 miles of aboveground power lines would be installed in the Project Area (Table 2–31). The short-term disturbance for these lines would be 7,978 acres (Table 2–32).

Workforce Requirements

Most of the active workforce involved in developing Alternative 3 would be occupied in construction-related activities. After roads and well pads are constructed, pipelines and utility lines are installed, and wells are drilled and completed, minimal personnel would be required to operate in the field. Table 2–36 shows the estimated employment requirements for the construction, operation, and reclamation of the project under Alternative 3.

Construction Resource Requirements

Construction of the project would require a variety of materials and equipment. The primary materials would be water, sand, and gravel. Additionally, small amounts of chemicals would be required. Machinery needed for construction would include heavy equipment (bulldozers, graders, track hoes, trenchers, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, pipelines, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct Alternative 3 is expected to be 2,765 acre-feet (Table 2–37). This water would be obtained from local sources.

Non-CBM Development

As with the CBM wells, development of non-CBM wells would continue to occur on non-federal minerals. The agencies assumed that development would be proportional to the areal extent of private and state minerals present in the Project Area. Table 2–38 shows the projected distribution of non-CBM wells.

Surface disturbance for a typical non-CBM well includes 2.25 acres for the well pad and 0.5 acres for a ⅓-mile bladed road, for a total of 2.75 acres disturbed for drilling operations. Part of the well pad area is reclaimed for production operations, and the entire area of disturbance is reclaimed when the well is plugged and abandoned.

Table 2–36 Estimated CBM Employment Requirements for Alternative 3

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	2,864	23
Well Pads	1 day/pad	10,572	2
Pipelines	2 days/mile	8,546	21
Electrical Utility Lines	2 days/mile	2,195	7
Drilling and Casing	4 days/well	15,504	26
Well Completion	2 days/well	15,504	47
Compressors (Recip.)	21 days/compressor	350	12
Compressors (Booster)	3 days/compressor	97	12
Surface Discharge Facilities	5 days/pond	419	4
Infiltration Facilities	24 days/impoundment	638	26
Containment Impoundment	90 days/impoundment	24	4
Land Application Disposal	20 days/facility	13	1
Injection Well	6.5 days/well	147	2
Total			187
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	10,572	58
Pumpers			0
Wells	15 days/pad/year	10,572	696
CMFs	30 days/10 wells/year	98	60
General Infrastructure	12 days/pad/year	10,572	556
Office	6 days/well/year	15,504	278
Well Workover	4 days/well/year	15,504	185
Compressors (Recip.)	52 days/compressor/year	350	31
Compressors (Booster)	12 days/compressor/year	97	2
Surface Discharge Facilities	25 days/pond/year	419	18
Infiltration Facilities	25 days/facility/year	638	27
Containment Impoundment	25 days/facility/year	24	1
Land Application Disposal	12 days/facility/year	13	3
Injection Well	25 days/well/year	147	6
Total			1,921
Decommissioning/Reclamation			
Wells	2 days/well	15,504	34
Roads	2 days/mile	2,864	1
Compressors (Recip.)	20 days/compressor	350	1
Compressors (Booster)	2 days/compressor	97	1
Reclamation	5 days/facility	10,572	84
Surface Discharge Facilities	2 days/pond	419	1
Infiltration Facilities	10 days/facility	638	1
Containment Impoundment	45 days/facility	24	1
Land Application Disposal	2 days/facility	13	1
Injection Well	2 days/well	147	1
Total			126

Note:

1. Estimates assume 300 working days per year.

Table 2–37 Summary of Requirements for Sand, Gravel, and Water under Alternative 3

Facility	Amount	Unit	Rate	Total Volume
Sand and Gravel				
Improved roads	2,864	miles	1,173 yd^3/mile	3,359,472
CMFs	1,550	CMFs	30 yd^3/CMF	46,512
Compressors	81	stations	1,100 yd3/station	89,100
Total (yd^3)				3,495,084
Water				
Roads	7,252	miles	0.1 acre-feet/mile	725
Pipelines	515	miles	0.04 acre-feet/mile	21
Well drilling	15,504	wells	0.08 acre-feet/well	1,240
Well completion	15,504	wells	0.05 acre-feet/well	775
Compressors	447	stations	0.01 acre-feet/compressor	4
Total (acre-feet)				2,765

Table 2–38 Projected Distribution of Non-CBM Wells under Alternative 3

	Potential for Oil and Gas				
Sub-watershed	Very Low	Low	Moderate	High	Total
Buffalo Field Office Area					
Little Bighorn River	5	0	0	0	5
Upper Tongue River	8	26	0	0	34
Middle Fork Powder River	6	2	0	0	8
North Fork Powder River	0	0	0	0	0
Upper Powder River	0	8	111	0	119
South Fork Powder River	3	0	0	0	3
Salt Creek	0	1	5	0	6
Crazy Woman Creek	1	7	0	0	8
Clear Creek	0	20	0	0	20
Middle Powder River	0	1	25	13	39
Little Powder River	0	0	76	472	548
Little Missouri River	0	0	0	33	33
Antelope Creek	0	0	24	0	24
Upper Cheyenne River	0	0	21	0	21
Upper Belle Fourche River	0	3	137	220	360
Total	23	68	399	738	1,228
Casper Field Office Area					
Converse County					74
Total					1,302

As shown on Table 2–39, 3,581 surface acres of the Project Area may be disturbed by construction of non-CBM wells. Most of this disturbance would occur in three watersheds: the Little Powder River, Upper Belle Fourche River, and Upper Powder River. After the wells are operational and partial reclamation has occurred, long-term disturbance would encompass about 85 percent of the original area disturbed.

Non-CBM development also would require a workforce involved in construction-related activities. Again, after roads and well pads are constructed and wells are drilled and completed, minimal personnel would be required to operate in the field. Table 2–40 shows the estimated employment requirements for the non-CBM wells.

Alternatives Considered but Eliminated from Detailed Analysis

Several potential alternatives were considered for this analysis but were eliminated from detailed study for various reasons. These alternatives are listed below, and the reasons they were excluded from further consideration are described.

Alternative Considered: Return all produced water to aquifers

Reasons Considered: This alternative was specifically developed to respond to issues about effects to aquifers and soils and the quantity and quality of surface water in and downstream of the Project Area. Under this alternative, the Companies would capture and actively return produced water to aquifers. Methods for accomplishing return include storage and retrieval wells, infiltration pits, land application (for example, spreaders and sprinklers), infiltration at clinker zones, and leach fields.

Reasons Dropped: The technical feasibility of an all-injection alternative appears to be limited. The nature of the groundwater flow systems and water chemistry in the PRB are not well understood, making it difficult to analyze the potential effects of widespread injection. Formations that are potential zones for injection may have limited capacity to accept the large volumes of water that would be injected. Existing groundwater in some potential zones for injection likely is unsuitable for mixing with water produced from CBM wells, if future retrieval of injected water for beneficial use is planned. Injection into some formations would degrade the quality of the water produced from CBM wells.

Table 2–39 Projected Maximum Disturbance Caused by Non-CBM Wells Under Alternative 3

	Areal Extent of Disturbance	
Sub-watershed	Short-term (acres)	Long-term (acres)
Buffalo Field Office Area and TBNG		
Little Bighorn River	14	12
Upper Tongue River	94	80
Middle Fork Powder River	22	19
North Fork Powder River	0	0
Upper Powder River	327	280
South Fork Powder River	8	7
Salt Creek	16	14
Crazy Woman Creek	22	19
Clear Creek	55	47
Middle Powder River	107	92
Little Powder River	1,507	1,288
Little Missouri River	91	78
Antelope Creek	66	56
Upper Cheyenne River	58	49
Upper Belle Fourche River	990	846
Total	3,377	2,886
Casper Field Office Area		
Converse County	204	174
Total	3,581	3,060

Note:

Maximum disturbance is based on 2.75 acres per well for short-term disturbance and 2 acres per well for long-term disturbance.

Table 2–40 Estimated Non-CBM Employment Requirements for Alternative 3

Work Category	Time Requirements per Unit	Number of Units	Average Number of Workers per Day
Construction and Installation			
Access Roads	0.5 day/mile	3,200	1
Well Pads	1 day/pad	3,200	1
Drilling and Casing	4 days/well	3,200	27
Well Completion	2 days/well	3,200	13
Total			42
Operation and Maintenance			
Road/Pad Maintenance	1 days/well	1,600	6
Pumpers			0
Wells	15 days/well/year	1,600	8
General Infrastructure	12 days/well/year	1,600	6
Office	6 days/well	1,600	3
Well Workover	4 days/well	1,600	2
Total			25
Decommissioning/Reclamation			
Wells	2 days/well	1,600	21
Roads	2 days/mile	1,600	2
Total			23

The economic feasibility of an all-injection alternative is unproven. To date, injection has been tested, but has not been shown to be economically viable in the PRB because of its high cost and uncertain success in disposing of all produced water over the life of a group of CBM wells. The high costs associated with injection would not be reasonable unless disposal of water by this method would be successful and the costs of this method would not cause development of CBM to become uneconomical. Development of CBM using injection as the only water handling method would eliminate the current beneficial use of water discharged from CBM wells, further reducing the economic feasibility of this alternative.

The ability of the BLM and FS to implement this alternative is limited. BLM and FS could not require the Companies to implement this alternative. Much of the Project Area involves non-federal minerals and non-federal surface, and BLM and FS have no jurisdiction. The alternatives considered in detail involve returning at least a portion of the produced water to aquifers.

Alternative Considered: Capture and treat produced water for additional beneficial uses.

Reasons Considered: Under this alternative, the Companies would capture the produced water, treat it, and make it available for additional beneficial uses. These uses include stock watering, wildlife habitat (aquatic, wetlands, and riparian), recreational opportunities (such as hunting waterfowl), and irrigation. In addition to responding to the issues about effects to aquifers and soils and the quantity and quality of surface water in and downstream of the Project Area, this alternative was developed to respond to effects on terrestrial wildlife, aquatic wildlife, and recreational opportunities.

Reasons Dropped: This alternative technically would not be feasible over the long term. Each CBM well is expected to produce water for a maximum of 7 years, with a peak in production occurring during the initial few years. Any additional beneficial uses provided if the agencies required the Companies to treat the produced water and make it available would essentially be relatively short term. Once the produced water from specific wells diminishes, the beneficial uses supported also would diminish. Thus, beneficial uses also would be short term wherever they would occur.

Alternative Considered: Staged rate or phased development.

Reasons Considered: This alternative was developed in response to a variety of the issues raised during scoping, including concerns about the volume of water discharged to local drainages. Staged or phased development was presented to BLM during scoping in several ways. First, the number of rigs operating in the Project Area could be controlled and leases would be developed in stages. Second, the Companies would be allowed to develop production in one geographic area at a time and when complete, move on to another area. Lastly, corridors could be left undeveloped to allow for wildlife movement.

Reasons Dropped: The State of Wyoming or private parties own much of the minerals and surface in the Project Area and the BLM and FS have no legal authority to direct the Companies in developing these leases. Additionally, the BLM and FS have a legal obligation to ensure that leased federal minerals are fully developed and that production occurring on non-federal leases does not drain federal minerals. This alternative is not reasonable in the case of existing leases because each lessee has an investment-backed expectation that its APDs will be considered in a timely manner and approved absent unacceptable site-specific impacts (see the Supreme Court decision in *Mobil Oil Exploration and Producing Southeast, Inc. v. United States*, 530 U.S. 604, 620 [2000] which found a breach of contract when the Minerals Management Service, pursuant to a later adopted statute, would not review and make a timely decision on development plans per the regulatory scheme in place at lease issuance.)

In addition, the Mineral Leasing Act and 43 CFR 3100 require maximum ultimate economic recovery of oil and gas from leased lands. In light of the broad geographic distribution of leases in the PRB, phased development in any fashion would not allow compliance with the above requirements.

Alternative Considered:	No action on all lands.
Reasons Considered:	This alternative was considered as a true No Action alternative under NEPA. Under this alternative, no further drilling or development of oil or gas wells would occur anywhere within the Project Area.
Reasons Dropped:	This alternative was eliminated from detailed consideration because it was not at all feasible. Development of fee and state minerals, particularly any already leased, would continue regardless of the decisions by BLM and FS. Because development of fee and state minerals undoubtedly will occur, BLM and FS decided a No Action alternative that involved development of fee and state minerals without the development of federal minerals would more closely resemble the actual situation of the BLM and FS denying any further development of CBM from federal minerals.

Alternative Considered:	Discharge produced water to the surface, but ensure that water quality at the Wyoming-Montana border does not change enough to adversely affect the uses of water at and downstream of the border.
Reasons Considered:	This alternative was considered as a means to address the State of Montana's concerns about the quality of surface water that enters the state. Under this alternative, the quality and quantity of discharges of produced water would be monitored to ensure that any changes in water quality at the state line would be insufficient to affect downstream uses of that water in Montana.
Reasons Dropped:	The Montana and Wyoming Powder River Interim Water Quality Criteria Memorandum of Cooperation essentially accomplished this alternative. If the monitoring conducted under this agreement suggests that produced water discharging into the rivers and subsequently into Montana may not meet the interim criteria, the Companies would be obliged to discontinue discharging the produced water that causes noncompliance with the MOC. The thresholds or criteria identified in the agreement are well below levels that would interfere with the existing uses of the water. Therefore, discharging the

	produced water would be discontinued before it would interfere with any downstream uses.
Alternative Considered:	Several environmental groups developed an alternative they identify as the "Conserving Wyoming's Heritage Alternative." This alternatives is based primarily on phased development, alternative and innovative technologies, adaptive management, the "reopening" of permits, landowner protections, injection and treatment of produced water, and minimizing adverse effects to the full range of resources present in the Project Area.
Reasons Considered:	This alternative was considered in response to comments submitted on the DEIS.
Reasons Dropped:	Considered as a whole, this alternative was unreasonable because it could not be implemented. A foundational element of the alternative was phased or staged development, which BLM and the FS have no legal means to implement, as discussed in the staged development alternative above. Another foundational element of this alternative was injection of water produced from CBM wells. The reasons this element was considered unreasonable are described above for the alternative of returning all produced water to aquifers. Finally, the other elements of the alternative (for example, injection) were already incorporated into the alternatives considered in detail.

Impact and Mitigation Monitoring and Reporting

Appendix D of this EIS contains a framework for a Mitigation Monitoring and Reporting Plan (MMRP) that would be adopted for this project. This framework was developed to:

- Verify implementation of mitigation measures adopted in the ROD;
- Measure the success rate of those mitigation measures;
- Make appropriate modifications to mitigation based on actual performance;
- Allow for peer review of mitigation and monitoring results; and
- Provide feedback to the interested public.

Summary of Alternatives and Environmental Consequences

The following tables summarize the alternatives considered in detail and the likely environmental consequences of each. Table 2–41 contains the summary of alternatives. This table contrasts the four alternatives in terms of their physical characteristics. The matrix presented in Table 2–42 provides a comparison summary of the effects to the various environmental resources that would occur by implementing each of the four alternatives for the Powder River Basin Oil and Gas Project.

Agency-Preferred Alternative

BLM's preferred alternative is a combination of Alternative 2A and Alternative 1. BLM prefers Alternative 2A for all parts of the project except the use of electric booster compressors. Thus, the portion of Alternative 1 preferred by BLM is the natural gas-fired compressors. The following discussion presents BLM's rationale for these preferences.

Although implementation of Alternative 2A for water may disturb more land and cost more than Alternative 1, BLM prefers Alternative 2A, emphasis on infiltration to reduce or mitigate impacts to water because:

1. Alternative 2A involves separate water management strategies for each sub-watershed that align with WDEQ's current approach to permitting.
2. The water management plans required under Alternative 2A would minimize the volume of water that reaches the main-stems in the sub-watersheds of the Little Powder River, Powder River, and Tongue River. This would reduce the potential for adverse effects on the water quality in the sub-basins most sensitive to potential changes in water quality, and most heavily used by irrigators.
3. Alternative 2A would maximize local beneficial use of the produced water rather than discharging the water downstream where the state and surface owners get no benefit from this resource.
4. Alternative 2A maximizes infiltration and storage of the produced water into the shallow aquifers of Wyoming, rather than having this resource pumped into surface waters that leave the state. This infiltration also would help with deeper aquifer recharge in the PRB.
5. Encourages treatment of produced water, where feasible and practicable.

BLM's preferred alternative retains the action as proposed with respect to the use of natural gas-fired compressors.

For Alternative 1, (natural gas fired compression engines) the analysis documents that the benefits to air quality and visibility from electrifying half or all of the booster compressors is negligible and would be insufficient to justify the additional costs of requiring the Companies to use electric booster compressors. An additional factor that led to this decision is the need for new power generation to provide electricity to these compressors. Also, the Companies would build relatively few booster compressors on surface owned by the Federal government and BLM does not have the ability to require electrification of compressors constructed off Federal surface. The State of Wyoming is responsible for permitting the compressors. The need for electrical compression as a condition of approval is best developed based on a case by case review of the emissions permit applications to be issued by the WDEQ. Choosing this option as the preferred alternative for air does not preclude the WDEQ from requiring the use of electric compression if determined to be necessary during its permitting process. This gives the WDEQ maximum flexibility to permit facilities in the most economical way that complies with applicable national and state air quality standards.

BLM and the State of Wyoming are committed to preventing any exceedence of air quality standards. In response to comments on the DEIS, BLM has used the same model for air quality impacts as the Montana BLM, and has gathered new data since the draft. Although the new model shows that there is a potential for greater air impacts than in the DEIS, the majority of these additional impacts result from other activities that are ongoing within the Project Area and not the project itself. BLM and the state will continue to monitor and implement adaptive management strategies at the permitting stage to assure that air quality in the region continues to meet federal and state goals for PM_{10}, HAPS, visibility impairment, and atmospheric deposition.

Table 2–41 Summary Comparison of Alternatives Considered in Detail

Parameter	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
New CBM Facilities				
Number of Wells				
Federal ownership	23,863	23,863	23,863	0
Non-federal ownership	15,504	15,504	15,504	15,504
Total	39,367	39,367	39,367	15,504
Number of Well Pads				
Federal ownership	15,425	15,425	15,425	0
Non-federal ownership	10,572	10,572	10,572	10,572
Total	25,997	25,997	25,997	10,572
Roads (miles)				
Improved	7,135	7,135	7,135	2,864
Two-track	10,619	10,619	10,619	4,387
Pipeline (miles)				
2–3-inch poly	14,127	14,127	14,127	5,836
12-inch poly	5,311	5,311	5,311	2,194
12-inch steel	1,408	1,408	1,408	516
Overhead Electric Line (miles)	5,311	5,311	5,311	2,194
Compressors				
Number of booster units	1,060	1,060	1,060	350
Number of booster stations	184	184	184	62
Total horsepower of booster units	371,000	371,000	371,000	122,500
Number of reciprocating units	298	298	298	97
Number of reciprocating stations	61	61	61	19
Total horsepower of reciprocating units	491,700	491,700	491,700	160,050
Water Handling Facilities				
Analyzed number of surface discharge facilities	1,217	606	878	419
Analyzed number of infiltration facilities	1,301	3,091	2,169	638
Analyzed number of containment impoundments	57	12	37	24
Analyzed number of injection wells	323	305	292	147
Analyzed number of LAD facilities	28	68	72	13
Projected Short-term Disturbance (acres)	193,589	202,843	199,233	79,052
Projected Long-term Disturbance (acres)	85,884	95,138	91,528	35,458
Workforce Requirements				
Construction and installation (peak no. of employees)	505	595	552	187
Operation and maintenance (peak no. of employees)	1,918	2,191	2,157	1,921
Reclamation and abandonment (peak no. of employees)	189	214	196	126
New non-CBM Facilities				
Number of new wells				
Federal ownership	1,791	1,791	1,791	0
Non-federal ownership	1,409	1,409	1,409	1,409
Total	3,200	3,200	3,200	1,409
Projected short-term disturbance (acres)	8,800	8,800	8,800	3,581
Projected long-term disturbance (acres)	7,520	7,520	7,520	3,060
Workforce Requirements				
Construction and installation (peak no. of employees)	42	42	42	42
Operation and maintenance (peak no. of employees)	25	25	25	25
Reclamation and abandonment (peak no. of employees)	23	23	23	23
Total Projected Disturbance (CBM and non-CBM)				
Projected short-term disturbance (acres)	202,389	211,643	208,033	82,633
Projected long-term disturbance (acres)	93,404	102,658	99,048	38,518

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Groundwater				
Removal	Remove 3,069,665 acre-feet during the life of the project, about 0.2 percent of the recoverable groundwater stored within the Wasatch and Fort Union Formations	Same as Alternative 1	Same as Alternative 1	Remove 1,627,742 acre-feet during the life of the project, about 0.1 percent of the recoverable groundwater stored within the Wasatch and Fort Union Formations.
Maximum Drawdown				
Fort Union Formation	Up to 800 feet	Same as Alternative 1	Same as Alternative 1	Similar to Alternative 1. However, the areal extent of the 25-foot drawdown contour would tend to decrease in areas where large concentrations of federal wells were projected to be drilled under Alternative 1, due to non-development under Alternative 3.
Deep Wasatch Sands	Deep Wasatch Sands within 100 feet of the coal zone could experience drawdowns that are 5 to 10 percent of the projected drawdown in the coal.	Same as Alternative 1	Same as Alternative 1	Similar to Alternative 1. However, in areas that would have had very high concentrations of federal wells under Alternative 1, the extent of drawdown within the Wasatch Sands would be less, because of non-development under Alternative 3.
Period of Maximum Drawdown				
Fort Union Formation	2006–2009	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Deep Wasatch Sands	Drawdown in the deep Wasatch Sands would occur several years after drawdown in the coal occurs.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Buildup				
Shallow Wasatch Sands	Up to 50 feet near impoundments. Up to 10 feet farther from impoundments.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Alluvium	Up to 10 feet has been documented; anticipated rise in water level could be more or less.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Infiltration and Recharge	Recharge of shallow Wasatch aquifer increased during CBM development as a result of infiltration below creeks and impoundments that receive CBM discharge water. An estimated 15 to33 percent of CBM produced water infiltrates the surface.	Similar to Alternative 1. An estimated 28 to 43 percent of CBM produced water infiltrates the surface	Similar to Alternative 1. An estimated 21 to 30 percent of CBM produced water infiltrates the surface.	Similar to Alternative 1, however, the volume of water produced under Alternative 3 would be a little more than half the volume of water produced under Alternative 1. Although the same percentage of CBM-produced water would infiltrate the surface, the volume of water infiltrating the surface likely would be reduced by half.
Quality	Groundwater quality within the regional aquifer systems and alluvial aquifers would not be noticeably affected.	Same as Alternative 1	Same as Alternative 1.	Same as Alternative 1
Recovery	Rapid initial recovery of water levels in developed coals following cessation of CBM pumping. Recovery to within 50 to 100 feet of pre-development water levels occurs by 2030. By 2060, water levels in the coal would recover to within 10 to 50 feet of pre-operational levels, exception in very localized areas of the basin. Water levels eventually would recover to within 20 feet or less of pre-operational levels over the next hundred years or so. Recovery of more than 50 percent in the deep Wasatch Sands would occur by 2030. Water levels eventually would recover to within less than 20 feet of pre-operational levels over the next hundred years or so.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Springs/Wells	Wells completed in developed coals that are located within the areal extent of the 100-foot drawdown contour could experience drops in water level and possibly methane occurrence. Flowing artesian wells and springs that emanate from coals in this area are likely to experience a decrease in flow rate. Recovery of artesian conditions likely would not occur unless recovery of the last five percent or so of hydraulic head occurs. Wells and springs in the Wasatch aquifer are not expected to be substantially affected unless they are within 100 feet (vertically) of developed coal.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Surface Water				
Quantity	An estimated 33 to 62 percent of CBM produced water would contribute to surface flows. Perennial flows likely to develop in formerly ephemeral channels	Similar to Alternative 1; an estimated 9 to 52 percent of CBM produced water would contribute to surface flows.	Similar to Alternative 1; an estimated 6 to 52 percent of CBM produced water would contribute to surface flows.	Similar to Alternative 1; however, the volume of water produced under this alternative would be a little more than half the volume produced under Alternative 1. Although the same percentage of CBM produced water would contribute to surface flows, the volume of water would be reduced by half.
CBM produced water discharged to main stems during peak year of water production	200,336acre-feet	131,937 acre-feet	125,109 acre-feet	102,917 acre-feet
Quality	Noticeable changes in water quality of main stems during periods of low flow. NPDES permit conditions would provide enforceable assurance that water quality standards and designated uses would not be degraded from discharges of CBM produced water.	Similar to Alternative 1; however, changes would be less noticeable because of the decrease in direct surface discharge.	Similar to Alternative 1; however, changes would be less noticeable because of the decrease in direct surface discharge and increase in the proportion of CBM produced water to undergo active treatment.	Similar to Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
	Concentrations of suspended sediment in surface waters likely to rise above present levels as a result of increased flows and runoff from disturbed areas.	Similar to Alternative 1	Similar to Alternative 1	Similar to Alternative 1
	SAR values and concentrations of sodium may inhibit the use of irrigation on some tributaries.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Use	Increased availability of surface water for irrigation and other downstream beneficial uses.	Similar to Alternative 1	Similar to Alternative 1; however, the volume of CBM produced water available to support beneficial use would be as much as 20 percent greater than under Alternative 1 because of the proportion of produced water to undergo active treatment.	Similar to Alternative 1; however, the volume of CBM produced water available to support beneficial use would decrease from Alternative 1 by about half.
	Numerous impoundments would be constructed to temporarily store CBM produced water for beneficial use. An estimated 6 to 23 percent of CBM produced water would be held in storage.	Similar to Alternative 1. An estimated 8 to 25 percent of CBM produced water would be held in storage.	Similar to Alternative 1. An estimated 7 to 24 percent of CBM produced water would be held in storage.	Similar to Alternative 1. Although the same percentage of CBM produced water would be held in storage, the volume of water stored would be reduced by about half.
Physiography, Geology, Paleontology, and Minerals				
Paleontology	If Class 3, 4, or 5 formations are present in areas of disturbance, ground-disturbing activities could damage or destroy surface and sub-surface fossils.	Similar to Alternative 1, but with a higher potential caused by the larger amount of disturbance.	Similar to Alternative 1, but with a higher potential caused by the larger amount of disturbance.	Similar to Alternative 1, but with a reduced potential caused by the smaller amount of disturbance.
Minerals	Would produce about 16 trillion cubic feet of CBM. Would produce about 220 million barrels of oil equivalent from the non-CBM wells.	Same as Alternative 1	Same as Alternative 1	Would produce about 8 trillion cubic feet of CBM. Considerable drainage of CBM resources from federal mineral ownership lands would occur. Would produce about 100 million barrels of oil equivalent from the non-CBM wells.

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Geological Hazards	Implementation is unlikely to cause noticeable ground subsidence or increase the potential for underground coal fires. Migration of some CBM could occur within the PRB as development of CMB occurs.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1, but to a smaller extent because of the smaller number of wells.
Soils				
Erosional effects from facilities located on soils with high wind erosion potential	Increased wind erosion caused by removal of vegetation, excavation, and stockpiling of soil, especially in sandy soils. Approximately 25,474 acres in the short term and 13,403 acres in the long term would be disturbed on soils with high wind erosion potential.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options. Because of the decrease in surface discharge and the increase in impoundments, the potential for wind erosion would increase slightly.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options. Because of the decrease in surface discharge and the increase impoundments, the potential for wind erosion would increase slightly, but less than in Alternative 2A.	All disturbances would be roughly cut in half. As Alternative 3 would employ the same water handling options as Alternative 1, effects would be similar but on a smaller scale.
Erosional effects from facilities located on soils with high water erosion potential	Increased water erosion and sedimentation caused by removal of vegetation, excavation, slope steepening, and compaction, especially in clayey soils. Approximately 76,691 acres in the short term and 38,452 acres in the long term would be disturbed on soils with high water erosion potential. Estimates of soil loss on these soils range from 3.4 to 18.7 tons/acre/year on bare soil and 0.5 to 2.6 tons/acre/year 1 year after reclamation.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options. Because of the decrease in surface discharge and the increase in impoundments, the potential for water erosion would increase slightly.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options. Because of the decrease in surface discharge and the increase in impoundments, the potential for water erosion would increase slightly, but the increase would be less than in Alternative 2A.	All disturbances would be roughly cut in half. As Alternative 3 would employ the same water handling options as Alternative 1, effects would be similar but on a smaller scale.
Facility location on slopes greater than 25 percent	No facilities would be located on slopes greater then 25 percent. Roads would be located to avoid steep slopes.	No facilities would be located on slopes greater then 25 percent. Roads would be located to avoid steep slopes.	No facilities would be located on slopes greater then 25 percent. Roads would be located to avoid steep slopes.	No facilities would be located on slopes greater then 25 percent. Roads would be located to avoid steep slopes.

Table 2–42 Summary of Effects, by Alternative

	Alternative			
Potential Effect	1	2A	2B	3
Effects on soil productivity	Reduction in soil productivity caused by removal of vegetation, compaction, changes in salinity, excavation, and stockpiling of soil. Implementation would disturb soils with high compaction potential (99,504 acres), low potential for revegetation (82,639 acres), high salinity (538 acres), or on Prime Agricultural (89,238 acres) soils.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options (additional 9,254 acres). Because of the decrease in surface discharge and the increase in impoundments, the potential for infiltration would be reduced, but soil mixing and compaction could increase slightly.	Nearly the same as Alternative 1, with a very minor increase in disturbed area because of the change in water handling options (additional 5,644 acres). Because of the decrease in surface discharge and the increase in impoundments, the potential for infiltration would be reduced, but soil mixing and compaction could increase slightly. These changes in effects from Alternative 1 would be less than would be experienced under Alternative 2A.	All disturbances would be roughly cut in half. As Alternative 3 would employ the same water handling options as Alternative 1, effects would be similar but on a much smaller scale (15,326 fewer acres of disturbance).
Air Quality				
Total near-field concentrations of criteria pollutants	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)
Cumulative near-field concentrations of criteria pollutants	Above PSD Class II increment for PM_{10} 24 hour; concentrations of other pollutants below increments	Below PSD Class II increments	Below PSD Class II increments	Below PSD Class II increments
Total far-field concentrations of criteria pollutants	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)	Compliance with Wyoming and national ambient air quality standards (WAAQS, NAAQS)
Cumulative far-field concentrations of NO_2 annual	Above PSD Class I increment in Northern Cheyenne Reservation. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation. Concentrations in other areas are below increments
Cumulative far-field concentrations of PM_{10} 24 hour	Above PSD Class I increment in Northern Cheyenne Reservation and Washakie Wilderness. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation and Washakie Wilderness. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation and Washakie Wilderness. Concentrations in other areas are below increments	Above PSD Class I increment in Northern Cheyenne Reservation. Concentrations in other areas are below increments
Maximum 8-hour concentrations of hazardous air pollutants (HAP)	Formaldehyde concentrations above strictest threshold, but well within range. Concentrations for other HAP within range of states' thresholds	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Cancer risk	Below threshold	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

	Alternative			
Potential Effect	1	2A	2B	3
Cumulative visibility impacts in mandatory federal Class I areas	Potential impacts range from 3 days above 1 dV at Red Rock Lakes Wilderness to 32 days above 1 dV at Wind Cave National Park. Potential maximum deciview change is 29 dV at UL Bend Wilderness.	Potential impacts range from 3 days above 1 dV at Red Rock Lakes Wilderness to 30 days above 1 dV at Wind Cave National Park. Potential maximum deciview change is 29 dV at UL Bend Wilderness.	Potential impacts range from 2 days above 1 dV at Red Rock Lakes Wilderness to 28 days above 1 dV at Wind Cave National Park. Potential maximum deciview change is 27 dV at UL Bend Wilderness.	Potential impacts range from 2 days above 1 dV at Red Rock Lakes Wilderness to 25 days above 1 dV at Wind Cave National Park. Potential maximum deciview change is 24 dV at UL Bend Wilderness.
Acidification of sensitive lakes	Potential impacts are 180% of the level of acceptable change (LAC) in Upper Frozen Lake and 104% of the LAC in Florence Lake. Impacts at other lakes are below the LAC.	Potential impacts are 175% of the level of acceptable change (LAC) in Upper Frozen Lake and 100% of the LAC in Florence Lake. Impacts at other lakes are below the LAC.	Potential impacts are 175% of the level of acceptable change (LAC) in Upper Frozen Lake. Impacts at other lakles are below the LAC.	Potential impacts are 175% of the level of acceptable change (LAC) in Upper Frozen Lake. Impacts at other lakes are below the LAC.
Vegetation				
Overall short-term vegetation loss	202,389 acres	211,643 acres	208,033 acres	82,633 acres
Overall long-term vegetation loss	93,404 acres	102,658 acres	99,048 acres	38,518 acres
Sagebrush shrublands (short-term without water handling facilities)	53,626 acres	53,626 acres	53,626 acres	21,106 acres
Riparian, wetlands (short-term without water handling facilities)	3,214 acres	3,214 acres	3,214 acres	3,229 acres
Wildlife				
Road density increase	1.40 mi/mi²	1.40 mi/mi²	1.40 mi/mi²	0.59 mi/mi²
Important habitats to species of big game				
Pronghorn winter-yearlong range	Approximately 1 percent of this range would be disturbed in the Project Area over the long term.	Same as Alternative 1	Same as Alternative 1	Less than 1 percent of this range would be disturbed in the Project Area over the long term.
White-tailed deer winter-yearlong and yearlong ranges	Less than 1 percent of both ranges would be disturbed in the Project Area over the long term; one hundred percent of the winter-yearlong disturbance would occur in the Middle Powder River sub-watershed.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative			
	1	2A	2B	3
Mule deer winter-yearlong range	Less than 1 percent of winter-yearlong range would be disturbed in the Project Area over the long term — about 50 percent of which would occur in the Upper Powder River sub-watershed.	Same as Alternative 1	Same as Alternative 1	Less than 1 percent of winter-yearlong range would be disturbed in the Project Area over the long term.
Elk crucial winter range (Fortification Creek)	Less than 1 percent of crucial winter range would be disturbed in the Fortification Creek Management Area.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Big game	Habitat fragmentation may alter big game habitat use. Human disturbance may displace big game from otherwise suitable habitats to lower-quality habitats. Nutritional status and reproductive success may be reduced. Increased human activities may result in increased vehicle collisions, poaching, and legal hunting success.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Raptors	Ground nesting and prey habitats would be disturbed. Increased human presence may alter raptor activity patterns. New utility poles may provide new perch sites for raptors. New aboveground lines and the potential for increased collisions between vehicles and wildlife may increase raptor mortality. Habitat disturbance may alter prey availability. Raptor population declines may occur.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Sage and plains sharp-tailed grouse	Disturbance of suitable nesting, feeding, and brood rearing habitats may occur. Increased human activity may affect nesting, breeding, and brood rearing activities. Increased aboveground utility lines may result in increased grouse collisions and raptor population. Populations, especially of sage grouse, may decline.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Waterfowl	Habitat disturbance may be beneficial or detrimental, depending on local hydrological conditions. Benefits include creation of new habitats and improvements of existing habitats. Produced waters may also eliminate or degrade existing habitats. Indirect effects to waterfowl may occur from exposure to elevated levels of salts and metals in production waters.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Migratory birds	Mortality from vehicle and power line collision would increase. Habitats would be lost, degraded, and fragmented. Populations of some species would decline. Populations may increase for species adapted to disturbed habitats.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Aquatic Life	Surface discharge of produced CBM water in 10 sub-watersheds could increase stream flows, sedimentation, and concentrations of salt and heavy metals in streams and ponds. Discharge of produced water to the surface under this alternative would result in the greatest potential effects to aquatic species of all the alternatives.	The same types of effects would occur to aquatic life under this alternative as under Alternative 1. The magnitude of the effects would be less under Alternative 2 because of an increased emphasis on containment and treatment.	Same as Alternative 2A	The same types of effects would occur under this alternative as under Alternative 1. However, the magnitude of these effects would be reduced by about 50 percent. The effects of Alternative 3 also would be smaller in magnitude than Alternative 2A or Alternative 2B.
Threatened, Endangered, or Proposed Species				
Black-tailed prairie dog	Project would directly affect individuals and suitable habitats.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Preble's meadow jumping mouse	No effect to this species based on the assumed lack of occurrence within the Project Area.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Black-footed ferret	Same as Alternative 2A	This alternative is not likely to adversely affect the ferret.	Same as Alternative 2A	Same as Alternative 2A

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Bald eagle	Same as Alternative 2A	This alternative is likely to adversely affect the bald eagle, but not likely to jeopardize the continued existence of the bald eagle.	Same as Alternative 2A	Same as Alternative 2A
Ute-ladies' tresses orchid	Same as Alternative 2A	This alternative is likely to adversely affect the orchid, but not likely to jeopardize the continued existence of the orchid.	Same as Alternative 2A	Same as Alternative 2A
Mountain plover	Same as Alternative 2A	This alternative is likely to adversely affect the mountain plover, but not likely to jeopardize the continued existence of the plover.	Same as Alternative 2A	Same as Alternative 2A
Western boreal toad	No effect to this species based on the lack of occurrence within the Project Area.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Cultural Resources				
Total number of cultural resource sites that may be affected (based on known site densities).	2,896	3,073	2,992	1,470
General Distribution of Effects	The greatest anticipated effects would be in the Clear Creek, Upper Powder River, Crazy Woman Creek, and Antelope Creek sub-watersheds. It is expected that 257 sites may be historic properties that require some form of protection or mitigation.	The greatest anticipated effects would be in the Clear Creek, Upper Powder River, Crazy Woman Creek, and Antelope Creek sub-watersheds. It is expected that 283 sites may be historic properties that require some form of protection or mitigation. Because of additional water handling facilities along the drainages, this alternative is likely to require more protective or mitigative measures than the other alternatives.	The greatest anticipated effects would be in the Clear Creek, Upper Powder River, Crazy Woman Creek, and Antelope Creek sub-watersheds. It is expected that 271 sites may be historic properties that require some form of protection or mitigation.	The greatest anticipated effects would be in the Clear Creek, Upper Powder River, Crazy Woman Creek, and Antelope Creek sub-watersheds. It is expected that 178 sites may be historic properties that require some form of protection or mitigation. Some infrastructure or support facilities may occur on federal surface for private development, but federal control over the identification and protection of historic properties would be minimal.
Land Use and Transportation				
Disturbance of Mixed Rangeland Resources by CBM and non-CBM facilities (excluding water handling facilities)				

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Short term (acres)	154,072	154,072	154,072	58,086
Long term (acres)	58,123	58,123	58,123	21,944
Additional Vehicle Trips for peak year (2007)	7,627	7,627	7,627	1,649
Visual Resources	A total of 316 wells, with their associated roads and water handling facilities would be constructed on VRM Class II areas on BLM lands. Class II management objectives would be met if mitigation were successfully implemented. Management objectives for 766 wells and associated facilities for Class III areas on BLM lands and 4,515 wells and associated facilities for BLM Class IV areas would be met. In addition, 369 wells and associated facilities would be constructed on TBNG areas managed with Scenic Integrity Objectives (SIO) of Low. Desired conditions for SIO would be met, in that facilities can be visible if they are reasonably mitigated to blend and harmonize with natural features.	Wells and roads are same as Alternative 1. Water handling methods would disturb 36,264 additional acres. Class II management objectives would be met if mitigation were successfully implemented.	Wells and roads are same as Alternative 1. Water handling methods would disturb 32,653 additional acres as in Alternative 2A. However, a smaller number of acres would be disturbed by impoundments than under Alternative 2A, with a proportionately smaller visual impact. Class II management objectives would be met if mitigation were successfully implemented.	No wells and associated facilities would be constructed on federal leases. Visual impacts from construction and operation would occur on state and private lands.
Recreational Resources	Construction would alter the recreational experience through a loss of solitude and the natural setting. After construction, the loss of solitude would be less because of greatly reduced traffic. Installation and operation of facilities would continue to affect the natural setting of the Project Area for the life of the project. Recreation in special management areas would not be affected. BLM and FS objectives for recreation would be met.	The effect on recreational opportunities from construction of wells and associated facilities is the same as Alternative 1. Water handling methods would disturb an additional 36,264 acres, resulting in a greater loss of solitude and the natural setting.	The effect on recreational opportunities from construction of wells and associated facilities is the same as Alternative 1. Water handling methods would disturb 32,653 additional acres as in Alternative 2A. However, a smaller number of acres would be disturbed by impoundments than under Alternative 2A, with a proportionately smaller loss of solitude and the natural setting.	No wells and associated facilities would be constructed on federal leases. No impacts to recreation would occur on BLM lands or the TBNG. Loss of solitude and natural setting could occur on state and private lands.

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Socioeconomics				
Effects to Employment	➢ During the peak year (2007), up to 5,579 workers would be required. ➢ Employment would be greatest between 2003 and 2011. ➢ The majority of the workers already live in the community; however, additional workers will be required. ➢ Secondary employment would be sustained for a longer period than previously anticipated and would increase as a result of new workers who move to the area.	➢ During the peak year (2007), up to 5,761 workers would be required. ➢ Employment would be greatest between 2003 and 2011. ➢ The majority of the workers already live in the community; however, additional workers will be required. ➢ Secondary employment would be sustained for a longer period than previously anticipated and would increase as a result of new workers who move to the area.	➢ During the peak year (2007), up to 5,663 workers are required. ➢ Employment would be greatest between 2003 and 2011. ➢ The majority of the workers already live in the community; however, additional workers will be required. ➢ Secondary employment would be sustained for a longer period than previously anticipated and would increase as a result of new workers who move to the area.	➢ Up to 1,481 workers would be required. ➢ Employment would be likely in first 10 years. ➢ Workers already available in the community.
Effects to Wages	➢ Combined annual payroll of the Companies would result in an estimated net present value of $570 million. ➢ Once the project is completed, total annual income in the four counties would decline.	➢ Combined annual payroll of the Companies would result in an estimated net present value of $642 million.	➢ Combined annual payroll of the Companies would result in an estimated net present value of $624 million.	➢ Combined annual payroll of the Companies would average an estimated net present value of $374 million.

Table 2–42 Summary of Effects, by Alternative

	Alternative			
Potential Effect	1	2A	2B	3
Effects on housing and community infrastructure	➢ Changes in employment/population are anticipated. Most employees are expected to be hired locally. However, during peak activity years, there would be a 7 percent increase in population. ➢ Rental vacancy rates for 2000 were 0.2 percent lower than the average for Wyoming. Additional rental units may be constructed if existing supply of vacant rental units becomes exhausted. ➢ The population influx is not expected to affect the water supply, wastewater systems, solid waste disposal, schools, fire protection, and medical facilities. ➢ The Proposed Action would result in increased traffic on roads and therefore demands for road maintenance (see transportation).	➢ No change from Proposed Action. ➢ Increase road maintenance as a result of construction and maintenance of water handling facilities.	Same as Alternative 2A	➢ Population would not change and there would be no negative housing or infrastructure effects.
Royalties and taxes generated (all net present value discounted at 10 percent)	➢ Federal Royalties = $1.7 billion ➢ State Royalties = $252 million ➢ Sales tax (4% paid to state, 1% paid to counties) = $124 million ➢ Severance (paid to state) = $1.3 billion ➢ Ad Valorem (paid to four counties) ➢ Campbell Co.= $821 million ➢ Converse Co.= $12 million ➢ Johnson Co.= $413 million ➢ Sheridan Co.= $269 million	➢ Same royalties as Proposed Action ➢ More taxes would be generated because of the number and cost of water handling facilities.	➢ Same as Alternative 2A ➢ Less royalties would be lost if electric compression is used, because of loss of royalties from leasehold for natural gas.	➢ $1.7 billon less in federal royalties ➢ $1.4 million less in severance tax ➢ $1.5 billion less in ad valorem tax ➢ Not drilling federal wells may result in future negative production rates from federal minerals, caused by drainage by drilling on state and private lands.

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Water handling cost to industry (all other development costs are constant among Alternatives 1, 2A, and 2B)	Surface Discharge = $818 million Infiltration = $505 million Containment =$93 million LAD= $26 million Injection =$130 million TOTAL =$1.57 billion	Surface Discharge = $458 million Infiltration = $1102 million Containment = $21 million LAD = $66.5 million Injection = $116 million TOTAL = $1.76 billion	Surface Discharge = $996 billion Infiltration = $786 million Containment = $61 million LAD= $70 million Injection = $111 million TOTAL = 2.0 billion	Surface Discharge = $382 million Infiltration = $292 million Containment = $40 million LAD = $13.6 million Injection = $72 million TOTAL = $799 million
Non-water handling costs (drilling, operation and maintenance, reclamation)	$17.27 billion	$17.27 billion	$17.27 billion	$6.84 billion
Net Cost of Alternative	$18.8 billion	$19.0 billion	$19.3 billion	$7.64 billion

Table 2–10 Projected Amount of Natural Gas Produced from CBM Wells under Alternative 1

	Total Cubic Feet of Methane Produced per Day by Year (in mmcf)									
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Little Bighorn River	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	22	36	56	72	84	89	91	92	92	92
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,078	1,705	2,056	2,284	2,319	2,301	2,225	1,905	1,317	819
South Fork Powder River	0	0	0	0	0	0	0	0	0	0
Salt Creek	7	11	13	15	15	14	14	12	8	4
Crazy Woman Creek	96	157	196	224	233	234	230	206	160	120
Clear Creek	56	88	115	135	147	152	155	154	147	141
Middle Powder River	8	12	18	22	26	27	27	27	27	27
Little Powder River	56	82	95	103	106	107	108	105	92	81
Little Missouri River	0	0	0	0	0	0	0	0	0	0
Antelope Creek	80	120	137	147	147	145	141	123	91	63
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	30	45	51	55	55	56	56	55	48	42
Lightning Creek	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	280	398	440	460	456	453	448	407	314	231
Middle North Platte River	0	0	0	0	0	0	0	0	0	0
Total	1,713	2,654	3,177	3,517	3,588	3,578	3,495	3,086	2,296	1,620

Source: Jones 2001

Table 2–11 Distribution of New Booster Compressor Units by Year and Sub-watershed — Alternative 1

	Year							
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	Total
Little Bighorn River	–	–	–	–	–	–	–	–
Upper Tongue River	3	6	8	6	5	2	1	31
Middle Fork Powder River	–	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–	–
Upper Powder River	195	250	141	91	14			691
South Fork Powder River	–	–	–	–	–	–	–	–
Salt Creek	1	2	1	–	–	–	–	4
Crazy Woman Creek	17	24	16	11	4	–	–	72
Clear Creek	10	13	11	8	4	2	1	49
Middle Powder River	2	1	3	1	2	–	–	9
Little Powder River	9	10	5	4	1	–	1	30
Little Missouri River	–	–	–	–	–	–	–	–
Antelope Creek	14	15	7	4	–	–	–	40
Dry Fork Cheyenne River	–	–	–	–	–	–	–	–
Upper Cheyenne River	6	5	3	1	1	–	–	16
Lightning Creek	–	–	–	–	–	–	–	–
Upper Belle Fourche River	47	47	17	7	–	–	–	118
Middle North Platte River	–	–	–	–	–	–	–	–
Total	304	373	212	133	31	4	3	1,060

Source: BLM 2001e

Table 2–12 Distribution of Booster Compressors by Size of Station and Sub-watershed — Alternative 1

	Booster Stations						
Sub-watershed	1-Unit	2-Unit	3-Unit	4-Unit	5-Unit	6-Unit	Total
Little Bighorn River	–	–	–	–	–	–	–
Upper Tongue River	–	–	1	1	–	4	6
Middle Fork Powder River	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–
Upper Powder River	–	–	1	1	–	114	116
South Fork Powder River	–	–	–	–	–	–	–
Salt Creek	1	–	1	–	–	–	2
Crazy Woman Creek	–	–	–	–	–	12	12
Clear Creek	–	–	1	1	–	7	9
Middle Powder River	1	–	–	2	–	–	3
Little Powder River	–	–	2	–	–	4	6
Little Missouri River	–	–	–	–	–	–	–
Antelope Creek	–	–	–	1	–	6	7
Dry Fork Cheyenne River	–	–	–	–	–	–	–
Upper Cheyenne River	–	–	–	1	–	2	3
Lightning Creek	–	–	–	–	–	–	–
Upper Belle Fourche River	–	–	–	1	–	19	20
Middle North Platte River	–	–	–	–	–	–	–
Total	2	0	6	8	0	168	184

Source: BLM 2001e

Table 2–13 Distribution of New Reciprocating Compressors by Year and Sub-watershed — Alternative 1

Sub-watershed	2002	2003	2004	2005	2006	2007	2008	Total
	Year							
Little Bighorn River	–	–	–	–	–	–	–	–
Upper Tongue River	1	2	2	1	2	–	1	9
Middle Fork Powder River	–	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–	–
Upper Powder River	54	70	39	25	4	–	–	192
South Fork Powder River	–	–	–	–	–	–	–	–
Salt Creek	–	1	–	–	–	–	–	1
Crazy Woman Creek	5	7	4	3	1	1	–	21
Clear Creek	3	3	3	3	1	–	1	14
Middle Powder River	–	1	–	1	–	–	1	3
Little Powder River	3	3	1	1	–	–	1	9
Little Missouri River	–	–	–	–	–	–	–	–
Antelope Creek	3	5	2	1	–	–	–	11
Dry Fork Cheyenne River	–	–	–	–	–	–	–	–
Upper Cheyenne River	2	1	1	1	–	–	–	5
Lightning Creek	–	–	–	–	–	–	–	–
Upper Belle Fourche River	13	13	4	3	–	–	–	33
Middle North Platte River	–	–	–	–	–	–	–	–
Total	84	106	56	39	8	1	4	298

Source: BLM 2001e

Table 2–14 Distribution of Reciprocating Compressors by Size of Station and Sub-watershed — Alternative 1

Sub-watershed	1-Unit	2-Unit	3-Unit	4-Unit	5-Unit	6-Unit	Total
	Reciprocating Stations						
Little Bighorn River	–	–	–	–	–	–	–
Upper Tongue River	–	–	1	–	–	1	2
Middle Fork Powder River	–	–	–	–	–	–	–
North Fork Powder River	–	–	–	–	–	–	–
Upper Powder River	–	–	6	–	–	29	35
South Fork Powder River	–	–	–	–	–	–	–
Salt Creek	1	–	–	–	–	–	1
Crazy Woman Creek	–	–	3	–	–	2	5
Clear Creek	–	1	–	–	–	1	2
Middle Powder River	–	–	1	–	–	–	1
Little Powder River	–	–	3	–	–	–	3
Little Missouri River	–	–	–	–	–	–	–
Antelope Creek	–	1	1	–	–	2	4
Dry Fork Cheyenne River	–	–	–	–	–	–	–
Upper Cheyenne River	–	1	1	–	–	–	2
Lightning Creek	–	–	–	–	–	–	–
Upper Belle Fourche River	–	–	1	–	–	5	6
Middle North Platte River	–	–	–	–	–	–	–
Total	1	3	17	0	0	40	61

Source: BLM 2001e

The compressor sites would be constructed in steps. After all necessary permits have been obtained, an access road would be constructed from an existing road to the site. Vegetation would be cleared and topsoil would be stripped and stockpiled. An area of about 2 acres (for booster stations) or 5 acres (for reciprocating stations) would be graded using standard cut-and-fill construction techniques and machinery (bulldozer or grader). Concurrent with construction of the compressors, gas pipelines would be built to the site. In addition, clear lamp lights (250 watts each) would be installed to light each compressor facility. Each light would be mounted on a pole or building and directed downward to illuminate key areas within the facility while minimizing the amount of light projected outside the facility.

The Companies currently propose to use natural gas-fired compressors at all locations. As the Project Area matures, the use of natural gas-fired compressors may diminish and selected units may be constructed with electric-powered compressors. Because the likelihood and extent of this replacement are unknown, the impact analysis documented for Alternative 1 in this EIS assumed that all compressors would be fired by natural gas. All compression internal combustion engines, any dehydration units, and any other emission sources must be permitted with WDEQ's Air Quality Division.

Glycol dehydration units also would be installed at each reciprocating compressor site. The dehydration units would be used to reduce the water in the gas stream to acceptable levels for commercial transportation. The units would have a design flow rate that would accommodate the compression capacity of the station.

High-pressure gas delivery pipelines that connect reciprocating compressor stations with existing and new transmission pipelines would be located along existing roads wherever possible. Disturbance related to these delivery lines is expected to be confined to areas not wider than 100 feet, located within rights-of-way that are already established, wherever possible.

A variety of high-pressure gas pipelines currently serves the PRB (Table 2–15). Separately and in combination, these high-pressure systems deliver gas into other high-pressure pipeline systems that are part of the natural gas grid in the U.S. These downstream facilities are classified as "interstate pipelines." The interstate pipeline companies currently receiving gas from the pipelines identified in Table 2–15 are Williston Basin Interstate, Wyoming Interstate Company, Ltd., KM Interstate Pipeline Company, and Colorado Interstate Gas Company.

Although Thunder Creek Gas Gathering Company, L.L.P., has not announced any expansion, prior statements by the company suggest the Thunder Creek system could be expanded to a capacity of at least 700,000 million cubic feet (mmcf) per day.

The four interstate pipeline companies or other interstate pipeline companies may seek to expand their systems as the ability to deliver CBM gas from the PRB grows. The expansion of any interstate pipelines would be subject to approval by the Federal Energy Regulatory Commission (FERC). FERC's rules and procedures require extensive environmental review as part of the certification process for any new interstate facilities. FERC can condition its approval of new interstate projects with environmental mitigation practices as are indicated necessary by the review of the individual project.

Table 2–15 Summary of High-pressure Pipelines Currently Operating in the Powder River Basin

Pipeline	Capacity (thousand cubic feet per day)
Fort Union Gas Gathering Company, L.L.P	634,000
Thunder Creek Gas Gathering Company, L.L.P	450,000
Big Horn Gathering Company, L.L.P.	450,000
Bittercreek Gathering Company	0
MIGC, Inc.	130,000
KMGGC, Inc.	140,000
Total	1,804,000

Workforce Requirements

Most of the active workforce assigned to develop the Proposed Action would be involved in construction-related activities. Only minimal personnel would be required to operate the field after roads and well pads are constructed, pipelines and utility lines are installed, and wells are drilled and completed. Table 2–16 shows the estimated employment requirements for construction, operation, and reclamation of the project under the Proposed Action.

Construction Resource Requirements

Construction of the project would require a variety of materials and equipment. The primary materials would be water, sand, and gravel. Additionally, small amounts of chemicals would be required. Machinery needed for construction would include heavy equipment (bulldozers, graders, track hoes, trenchers, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, pipelines, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct the Proposed Action is expected to be 6,963 acre-feet (Table 2–17). This water would be obtained from local sources.

Production and Maintenance

Roads

Routine maintenance in the Project Area would occur on a year-round basis or as ground and site conditions permit. This maintenance program includes postponing travel on the two-track roads during and immediately after wet weather when vehicular traffic could cause rutting. Summer (late spring to early fall) road maintenance could include the addition of gravel and blading improved roads consistent with "traveled road maintenance operations" in the area. Other routine maintenance could include grading the borrow ditches and cleaning out culverts and low-water crossings. Noxious weeds also would require yearly control along roads. Winter (late fall to early spring) maintenance would include blading snow from access roads and some summer-like maintenance when necessary and permitted by weather conditions. The Companies would not routinely employ dust abatement procedures on roads within the Project Area during production and maintenance.

Table 2–16 Estimated CBM Employment Requirements for Alternative 1

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	1,217	14
Infiltration Facilities	24 days/impoundment	1,301	72
Containment Impoundment	90 days/impoundment	57	12
Land Application Disposal	20 days/facility	28	4
Injection Well	6.5 days/well	323	5
Total			505
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			-
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	1,217	71
Infiltration Facilities	25 days/facility/year	1,301	75
Containment Impoundment	25 days/facility/year	57	3
Land Application Disposal	12 days/facility/year	28	8
Injection Well	25 days/well/year	323	19
Total			1,918
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	1,217	4
Infiltration Facilities	10 days/facility	1,301	23
Containment Impoundment	45 days/facility	57	5
Land Application Disposal	2 days/facility	578	2
Injection Well	2 days/well	323	1
Total			189

Note:

1. Estimates assume 300 working days per year.

Table 2–17 Summary of Requirements for Sand, Gravel, and Water under Alternative 1

Facility	Amount	Unit	Rate	Total Volume
Sand and Gravel				
Improved roads	7,136	miles	1,173 yd^3/mile	8,370,528
CMFs	394	CMFs	30 yd^3/CMF	11,820
Compressors	245	stations	1,100 yd^3/station	269,500
Total (yd^3)				8,651,848
Water				
Roads	17,755	miles	0.1 acre-feet/mile	1,776
Pipelines	1,408	miles	0.04 acre-feet/mile	56
Well drilling	39,367	wells	0.08 acre-feet/well	3,149
Well completion	39,367	wells	0.05 acre-feet/well	1,968
Compressors	1,358	Compressor	0.01 acre-feet/compressor	14
Total (acre-feet)				6,963

The counties and Companies would have primary responsibility for maintaining the project's improved roads in the Project Area. The counties would continue to maintain existing county roads. The Companies would maintain all other project roads.

When the project is complete, all roads constructed specifically for the project would be removed and reclaimed unless the landowner or county specifically requests that a road be retained. If a landowner decides to keep a road, then the landowner would accept responsibility for maintaining it after it was abandoned by the Companies. The counties would continue to maintain existing county roads and any roads covered by maintenance agreements with BLM.

Wells

Routine Maintenance A maintenance person (a "pumper") may visit each well up to once per day to ensure that the equipment is functioning properly. Automated well monitoring equipment already in operation allows the pumper to visit less frequently, depending on well location, reliability, and other factors. Field personnel would routinely calculate balances between wells and collection and transfer points to ensure that the volumes match within acceptable tolerances. Significant leaks in gas or water pipelines would cause a loss of pressure that would be detectable by the static pressure on the meter run. If a leak is detected, a well would be shut in. The shut-in point would be identified for each well based on individual operating conditions. Field leaks would then be pinpointed using pressures measured in the field, and the problem would be corrected. Maintenance of the various mechanical components of the gas production would occur at intervals recommended by manufacturers or as needed based on site visits.

Additional remote (off-site) computerized monitoring system may be installed if warranted by the number of total producing wells and cost effectiveness. If it is installed, the automated monitoring system would allow remote monitoring of operations at each well. The system would monitor various operating conditions (such as gas and water production rates, pipeline pressure, and separator pressure) to evaluate whether abnormal conditions exist. Electrical cables laid to the wells would provide power to the automation equipment. The operating conditions at the well site would be transmitted via radio to a local, central facility. Maintenance personnel would be immediately dispatched to the well site if a problem is identified. The radio-controlled system would allow real-time signals and solutions in response to well production problems. Control and monitoring of well production by radio telemetry would reduce regular site inspections of each well and would limit vehicular traffic to approximately once a week to each well. However, other factors, such as the need for visual inspection of gas and water pipelines, may require daily visits for safety and environmental reasons.

Workovers Periodically, a workover on a well would be required. A workover uses a truck-mounted unit similar to a completion rig to ensure that the well is maintained in good condition and is capable of extracting natural gas as efficiently as possible. Workovers are typically needed within the first few months after initial completion to remove coal fines from pumps. Workovers can include repairs to the well bore equipment (casing, tubing, rods, or pumps), the wellhead, or the production formation. These workovers may require venting pressure. Routine repairs would occur only during daylight hours and are usually completed within 1 day. Several days may be required to complete a workover in some limited situations. Although the frequency of workovers cannot be predicted because the requirements vary from well to well, each new well would likely require a workover during the first year of production.

Pipelines

Gas-gathering and produced water pipelines would be routinely inspected along with other facilities. Procedures would be incorporated with inspection of meters at the well sites. If pressure losses are detected, the wells would be shut in until the problem is isolated and addressed.

Electrical Utilities

Routine inspection and maintenance of electric utilities would be done by the utility provider.

Decommissioning and Reclamation

Dry holes would be reclaimed following the procedures described below, except that reclamation would begin as soon as possible after the decision is made that the well would not produce or that it is depleted of gas. The following sections describe the overall procedures the Companies would follow to reclaim the disturbance to as near as possible to pre-development conditions.

Roads

At a minimum, access roads would be reclaimed by ripping or plowing and drill seeding unless the landowner or land manager wishes to make use of any roads and accepts responsibility through execution of a release for future maintenance. Improved roads that are not needed for further use would be blocked, recontoured, reclaimed, and vegetated consistent with the requirements of the federal land managers (according to Onshore Oil and Gas Order No. 1, Approval of Operations) and the State of Wyoming. On private lands, the Companies would execute release of the road to the landowner or reclaim it according to the terms of surface use agreements that may be in effect at that time.

All road disturbances on federal lands would be reseeded with a seed mixture approved by the Authorized Officer, as described in the APD Surface Use Program or COAs. The seed mixture would be planted in the amounts specified in pounds of pure live seed per acre. All seed would be certified as weed free. Seed would be tested in accordance with state laws and within 12 months before purchase. Commercial seed either would be certified or registered. Seeding and planting would be repeated until satisfactory revegetation is achieved. Multi-year control of noxious weeds may be needed on some reclaimed areas.

Wells

All surface facilities would be removed. Depleted production holes would be plugged and abandoned in accordance with Onshore Oil and Gas Order No. 2 and WOGCC's rules. Once the well is conditioned as a static column, the well would be decommissioned by pouring redundant plugs, a slurry of cement and water, at strategic locations in the well bore. These locations would be based on each well's configuration, but would be placed to prevent migration of fluids or gas up the well bore or any uncemented paths. A mixture of bentonite and water would be placed between the cement plugs. Well pads would be recontoured, plowed, and seeded consistent with the procedures described in the APD Surface Use Program or COAs. The Companies also may assign wells to the landowner consistent with the terms of the surface use agreement. When the well is assigned, all rights and responsibilities, including reclamation, pass to the landowner, unless otherwise specified. The landowner must then properly permit the well for beneficial uses after CBM production has ceased according to WSEO's procedures and policies.

Pipelines

The procedures for decommissioning and reclaiming pipelines are straightforward. The underground pipelines would be cleaned, disconnected, and then abandoned in place to avoid any unnecessary surface disturbance, as noted in the COAs for the APD or the POD for the ROW or SUP. Any surface disturbances associated with the underground pipelines are addressed in previous sections.

Electrical Utilities

Underground electric lines would be disconnected and abandoned in place to avoid any unnecessary surface disturbance. Aboveground lines would be disconnected and the power poles would be removed from the sites. Surface disturbance associated with the removal would be reclaimed according to the COAs for the APD or the POD for the ROW or SUP.

Non-CBM Development

BLM has evaluated the potential for non-CBM oil and gas resources to occur and be developed in the Project Area. In part, this evaluation resulted in the mapping

of various levels of potential (such as very low, low, moderate, or high) within the Buffalo Field Office Area (BFOA). It also resulted in three levels of potential development, which are documented in BLM's RFD Scenario for the Buffalo Field Office (BLM 2001f).

The moderate level of development under BLM's RFD Scenario, which is the basis for this alternative, projects that about 3,200 non-CBM wells will be drilled and completed within the Project Area over the 10-year period. As shown on Table 2–18, 3,000 of these wells would be drilled in the portion of the Project Area that is under the jurisdiction of the Buffalo Field Office (BFO) and FS. The remaining 200 wells would be drilled in the portion of the Project Area under the jurisdiction of the Casper Field Office (CFO).

Table 2–18 Projected Distribution of Non-CBM Wells Under Alternative 1

Sub-watershed	Potential for Oil and Gas				Total
	Very Low	Low	Moderate	High	
Buffalo Field Office Area and TBNG					
Little Bighorn River	5	0	0	0	5
Upper Tongue River	8	36	0	0	44
Middle Fork Powder River	20	4	0	0	24
North Fork Powder River	1	0	0	0	1
Upper Powder River	0	20	377	0	397
South Fork Powder River	3	0	0	0	3
Salt Creek	0	5	13	0	18
Crazy Woman Creek	3	11	2	0	16
Clear Creek	0	28	0	0	28
Middle Powder River	0	6	71	37	114
Little Powder River	0	0	166	1,368	1,534
Little Missouri River	0	0	2	92	94
Antelope Creek	0	0	67	0	67
Upper Cheyenne River	0	7	39	0	46
Upper Belle Fourche River	0	3	213	393	609
Total	40	120	950	1,890	3,000
Casper Field Office Area					
Converse County					200
Total					3,200

Surface disturbance for a typical oil well (from 5,000 to 12,000 feet deep) includes 2.25 acres for the well pad and 0.5 acres for a ⅓-mile long bladed road, for a total of 2.75 acres disturbed for drilling operations. Part of the well pad area is reclaimed as production operations begin. The entire area of disturbance is reclaimed when the well is plugged and abandoned.

As shown on Table 2–19, about 8,800 surface acres of the Project Area may be disturbed by the construction of non-CBM wells. Most of this disturbance would occur in three sub-watersheds. They are Little Powder River, Upper Belle Fourche River, and Upper Powder River. Once the wells are operational and partial reclamation has occurred, long-term disturbance would encompass about 82 percent of the original disturbance.

Table 2–19 Projected Maximum Disturbance Caused by Non-CBM Wells Under Alternative 1

	Areal Extent of Disturbance	
Sub-watershed	Short term (acres)	Long term (acres)
Buffalo Field Office Area and TBNG		
Little Bighorn River	14	12
Upper Tongue River	121	103
Middle Fork Powder River	66	56
North Fork Powder River	3	2
Upper Powder River	1,092	933
South Fork Powder River	8	7
Salt Creek	50	42
Crazy Woman Creek	44	38
Clear Creek	77	66
Middle Powder River	314	268
Little Powder River	4,219	3,605
Little Missouri River	259	221
Antelope Creek	184	157
Upper Cheyenne River	127	108
Upper Belle Fourche River	1,675	1,431
Total	8,250	7,050
Casper Field Office Area		
Converse County	550	470
Total	8,800	7,520

Note:
Maximum disturbance is based on 2.75 acres per well for short-term disturbances and 2.0 acres per well for long-term disturbances.

The non-CBM development also would require a workforce involved in construction-related activities. After roads and well pads are constructed and wells are drilled and completed, minimal personnel would be required to operate the field. Table 2–20 shows the estimated employment requirements for the non-CBM wells.

Safety/Emergency Response

This section outlines the methods that the Companies would employ to ensure the safe operation of the oil and gas wells during development and production. It also describes how the Companies would respond to emergencies. In cooperation with the WOGCC and Wyoming Occupational Safety and Health Administration, the Companies have undertaken a comprehensive study of safety regulations currently in place related to the development and will recommend to the agencies of jurisdiction any changes deemed necessary to protect the health and safety of the public as well as those employed in the development.

Geologic Hazards

During drilling operations, abnormally high formation pressure could be encountered, which could result in an uncontrolled well condition. However, more than 6,000 CBM wells have been drilled in the Project Area with no instances of abnormally high pressure. Blowouts are considered highly unlikely because of the shallow depths of the wells, normal and below-normal pressures in the formations, and experience in the Project Area. WOGCC and BLM require diverters after the surface casing has been set.

Table 2–20 Estimated Non-CBM Employment Requirements for Alternative 1

Work Category	Time Requirements per Unit	Number of Units	Average Number of Workers per Day
Construction and Installation			
Access Roads	0.5 day/mile	3,200	1
Well Pads	1 day/pad	3,200	1
Drilling and Casing	4 days/well	3,200	27
Well Completion	2 days/well	3,200	13
Total			42
Operation and Maintenance			
Road/Pad Maintenance	1 days/well	1,600	6
Pumpers			0
Wells	15 days/well/year	1,600	8
General Infrastructure	12 days/well/year	1,600	6
Office	6 days/well	1,600	3
Well Workover	4 days/well	1,600	2
Total			25
Decommissioning/Reclamation			
Wells	2 days/well	1,600	21
Roads	2 days/mile	1,600	2
Total			23

Fires and Explosions

The potential for leaks or ruptures in gas flowlines or pipelines would exist. Most ruptures are the result of heavy equipment that accidentally strikes the pipeline while it is operating nearby. These ruptures could result in an explosion and fire if a spark or open flame ignites the escaping gas. The materials used in the pipelines would be designed and selected according to applicable standards to minimize the potential for a leak or rupture. Frequent markers along the pipelines would reduce the risk of accidental ruptures from excavating equipment. Additionally, the Companies would monitor the flow in the pipeline by either remote sensors or daily inspections of the flow meters, which would reduce the probability of ruptures through prompt detection of leaks.

Well fires are rare, but could occur under certain conditions. For the reasons listed in the previous sections, the probability of a blowout is very low. The Companies would include procedures for reporting and controlling fires in the emergency response programs. The Companies have and would continue to conduct cooperative training exercises with the fire and rescue departments within the Project Area.

Public Safety

The Companies would take measures to protect the public from hazards at wells. Warning signs would be posted around facilities, as necessary. In addition, compressor stations would be fenced and gated.

Employee Safety

The Companies would develop Emergency Plans that would cover all potential emergencies, including fires, employee injuries, and chemical releases, among others. The plans would include telephone numbers for all medical and emergency services and the contacts in event of emergencies. In addition, the Companies would not allow employees and contractors to bring firearms into the area. The plans would be posted at all the Companies' local offices and field facilities. All employees and subcontractors would be trained on the Emergency Plan when they are hired and refresher courses would be presented annually.

Water Monitoring and Mitigation

Monitoring and mitigation for both groundwater and surface water are a substantial part of the Proposed Action. The Companies are conducting, and propose to continue to conduct, hydrologic monitoring to obtain information that would enable them to detect impacts on other water users and to control activities and operations to assure regulatory compliance and public protection.

Mitigation measures include establishment of monitoring wells and stream gauges. The Companies work with the surface owners to establish water controls, diversions, and uses for the surface discharges. Treatment, injection, and storage may be used where necessary and practicable.

Groundwater

Under the current groundwater monitoring approach supported by the Wyodak EIS and previous CBM planning documents, BLM is requiring the installation and operation of approximately two pairs of monitor wells per township throughout the CBM probable development area. BLM proposes to modify this approach to require the drilling of a reduced number (approximately 35) of strategically located, somewhat more complex (more wells per location) locations in the next two years. The goal is to complete these wells as far ahead of development as possible. By concentrating data collection efforts at a reduced number of more comprehensive locations, more complete site-specific and inter-aquifer information can be collected and still have adequate coverage throughout the basin for a regional analysis. In addition, we will end up with better baseline data by having most of the wells drilled prior to development.

All operators on federal minerals are required to offer a Water Well Agreement as set forth in the Gillette South EIS and the Wyodak EIS. This agreement protects nearby water wells permitted by WSEO. The Companies generally offer the same agreement when they are drilling on fee and state lands.

Surface Water

The Companies are required to monitor and report produced water volumes and quality to WDEQ pursuant to the requirements of the NPDES permit. Discharges are required to meet all applicable WDEQ water quality standards and regulations at all times. The Companies also must report produced water volumes to the WOGCC and WSEO.

The BLM water management plans, FS, and WDEQ require the Companies to use BMPs that would prevent erosion and damage to agricultural activities.

Surface gauging stations may be needed on the Little Powder, Powder, Belle Fourche, Cheyenne, and Tongue Rivers. The cost of this monitoring would be shared among BLM, the U.S. Department of the Interior, Geological Survey (USGS), and the Companies.

BLM would periodically monitor water quality by sampling at discharge points and on streams. BLM also would monitor selected stream channels that receive CBM discharged water for signs of accelerated erosion and degradation.

In August 2001, the States of Montana and Wyoming signed an Interim MOC to document their commitments and intent to protect and maintain water quality in the PRB within Montana during an 18-month interim period (Appendix B). At the conclusion of this interim period, the states will negotiate a final MOC that will include recognition of protective water quality standards and allocation of any assimilative capacity. A monitoring program to implement the interim MOC and to assist in development of a final MOC is part of the agreement. Currently, the states are developing this monitoring program. Once it has been developed, the aspects of the monitoring plan that are applicable to the oil and gas development addressed in this EIS would be incorporated into the ROD.

Alternative 2 — Proposed Action with Reduced Emission Levels and Expanded Produced Water Handling Scenarios

Alternative 2 was developed specifically to respond to four of the 18 key issues. They are the issues addressing effects of the Proposed Action on aquifers (Issue 1), the quantity and quality of surface waters (Issues 2 and 3), and effects on air quality and visibility (Issue 6). BLM and FS altered the Proposed Action in two primary areas to respond to these issues: handling of produced water and compression of gas. Other than the differences described below, Alternative 2 is the same as the Proposed Action.

Methods for Handling Produced Water

The overall methods for handling the disposal of produced water are the same as were included in the Proposed Action. However, BLM and FS have altered the distribution of produced water among the methods to emphasize handling in two ways: infiltration and treatment. As shown on Table 2–21, Alternative 2A emphasizes use of infiltration impoundments to dispose of CMB produced water. In contrast, Alternative 2B emphasizes the use of passive and active treatment to dispose of CBM produced water (Table 2–22). The emphasis of these alternatives was developed in response to WDEQ's projections for how CBM produced water probably would be handled in the future to meet the MOC between Montana and Wyoming on Interim Water Quality Criteria (Appendix B).

The changes in methods of water handling included as part of Alternatives 2A and 2B slightly alter the number of acres that would be disturbed. Instead of affecting 193,589 acres of short-term disturbance as under Alternative 1, Alternative 2A would affect 202,843 acres over the short term (Table 2–23). Long-term disturbance associated with Alternative 2A also would be slightly less, at

95,138 acres (Table 2–24). In contrast, Alternative 2B would affect 199,233 acres over the short term (Table 2–25) and 91,528 acres over the long term (Table 2–26).

Table 2–21 Assumed Water Handling Methods for CBM Wells with an Infiltration Emphasis — Alternative 2A

	Water Handling Method[1,2,3]						
	NPDES-permitted Discharge						
Sub-watershed	Untreated Discharge (percent)	Passive Treatment (percent)	Active Treatment (percent)	Infiltration Impoundment (percent)	Containment Impoundment (percent)	LAD (percent)	Injection (percent)
Upper Tongue River	0	5	0	65	5	15	10
Upper Powder River	0	30	0	60	0	5	5
Salt Creek	0	0	0	70	5	5	20
Crazy Woman Creek	0	5	0	70	5	10	10
Clear Creek	0	5	0	70	5	10	10
Middle Powder River	0	30	0	55	0	10	5
Little Powder River	0	40	0	45	0	10	5
Antelope Creek	0	60	0	30	0	5	5
Upper Cheyenne River	0	60	0	30	0	5	5
Upper Belle Fourche River	30	30	0	30	0	5	5

Notes:

1. The percentages shown represent the distribution of water handling methods assumed for the analysis, not the amount of water that actually reaches the river.
2. Handling Methods:
   NPDES-permitted Discharge – includes methods of handling the produced water that require an NPDES permit.
   Untreated discharge – water that is discharged onto the surface of the ground without any treatment.
   Passive treatment – water that is amended through passive methods to meet standards before discharge. An example of this method is passing the water over scoria to remove iron.
   Active treatment – water that is amended through active methods to meet standards before discharge. An example of this method is passing the water through a reverse osmosis system.
   Infiltration impoundment – water contained in upland and bottomland impoundments allowing for infiltration and groundwater recharge. Infiltration impoundments constructed in-channel may allow for overflow under given storm events.
   Containment impoundment – includes upland impoundments, lined, with minimal infiltration and no direct surface discharge or lateral subsurface movement of water and down-gradient expression in seeps or springs. These impoundments are permitted by WOGCC.
   LAD = land application disposal. Typically, land application is achieved by spraying produced water through agricultural irrigation equipment and high-pressure atomizers.
   Injection – represents that water that is injected into disposal wells.
3. The above percentages are not upper thresholds that can or will be enforced. They are merely a disclosure of effects of one of many various ways water may be handled to meet the Wyoming water quality standards and agreement with bordering states.

Compression

This alternative includes two options for compression of the CBM, both of which were analyzed in detail. The first option is electrification of 50 percent of the booster compressors. Under this option, half of the new 1,060 booster compressor units would be electrically powered. The other half would be gas-fired units. The power for the electrical units would be brought to the compressor stations via the same power lines that are included in the Proposed Action. Thus, no new external construction would be required. Except for the exchange of gas-fired booster units for electrical booster units, no other visible changes would occur. Reciprocating compressors would remain the same.

Table 2–22 Assumed Water Handling Methods for CBM Wells with a Treatment Emphasis — Alternative 2B

	Water Handling Method[1,2,3]						
	NPDES-permitted Discharge						
Sub-watershed	Untreated Discharge (percent)	Passive Treatment (percent)	Active Treatment (percent)	Infiltration Impoundment (percent)	Containment Impoundment (percent)	LAD (percent)	Injection (percent)
Upper Tongue River	0	5	20	45	5	15	10
Upper Powder River	0	30	15	40	5	5	5
Salt Creek	0	0	15	50	10	5	20
Crazy Woman Creek	0	5	20	45	5	15	10
Clear Creek	0	5	20	50	5	10	10
Middle Powder River	0	30	10	40	5	10	5
Little Powder River	0	40	20	25	0	10	5
Antelope Creek	0	60	10	25	0	5	0
Upper Cheyenne River	0	60	10	25	0	5	0
Upper Belle Fourche River	30	30	0	30	0	5	5

Notes:

1. The percentages shown represent the distribution of water handling methods assumed for the analysis, not the amount of water that actually reaches the river.
2. Handling Methods:
   NPDES-permitted Discharge – includes methods of handling the produced water that require an NPDES permit.
   Untreated discharge – water that is discharged onto the surface of the ground without any treatment.
   Passive treatment – water that is amended through passive methods to meet standards before discharge. An example of this method is passing the water over scoria to remove iron.
   Active treatment – water that is amended through active methods to meet standards before discharge. An example of this method is passing the water through a reverse osmosis system.
   Infiltration impoundment – water contained in upland and bottomland impoundments allowing for infiltration and groundwater recharge. Infiltration impoundments constructed in-channel may allow for overflow under given storm events.
   Containment impoundment – includes upland impoundments, lined, with minimal infiltration and no direct surface discharge or lateral subsurface movement of water and down-gradient expression in seeps or springs. These impoundments are permitted by WOGCC.
   LAD = land application disposal. Typically, land application is achieved by spraying produced water through agricultural irrigation equipment and high-pressure atomizers.
   Injection – represents that water that is injected into disposal wells.
3. The above percentages are not upper thresholds that can or will be enforced. They are merely a disclosure of effects of one of many various ways water may be handled to meet Wyoming's water quality standards and agreements with bordering states.

The second option analyzed under this alternative was electrification of all 1,060 new booster compressor units. Under this option, no new gas-fired boosters would be constructed. All would be powered by electricity. As noted above, no new external construction would be required and the reciprocating compressors would continue to be gas-fired units.

Under both of these options, new power generation capacity would be required to provide the electricity needed for the electrical booster and reciprocating compressors. The potential locations and sizes of the facilities that could be constructed to provide the necessary additional capacity are too numerous and speculative to evaluate in this analysis.

As a result of the changes in water handling for Alternatives 2A and 2B relative to Alternative 1, additional employees would be needed to construct, operate, maintain, decommission, and reclaim the facilities. Table 2–27 and Table 2–28 summarize the estimated employment requirements for Alternatives 2A and 2B.

Table 2–23 Summary of Estimated Short-term CBM Disturbance Associated with Alternative 2A

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	631	59	1,542	520	2,075	782	3,133	248	727	782	10	12	10,521
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	4,978	435	11,635	3,639	14,529	5,458	17,165	2,408	6,327	5,458	175	232	72,439
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	11	1	234	88	350	132	46	24	121	132	5	4	1,148
Crazy Woman Creek	773	67	2,374	824	3,288	1,234	3,460	364	1,187	1,234	25	24	14,854
Clear Creek	1,010	86	2,363	908	3,623	1,362	4,447	320	778	1,362	10	18	16,287
Middle Powder River	238	22	682	188	752	283	891	206	267	283	5	6	3,823
Little Powder River	534	47	2,548	1,058	4,222	1,586	1,730	327	485	1,586	15	12	14,150
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	474	38	7,703	3,683	14,694	5,524	1,093	191	417	5,524	20	14	39,375
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	160	12	812	166	662	249	354	291	455	249	10	6	3,426
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	1,664	136	4,701	1,798	7,176	2,702	3,944	473	1,455	2,702	30	40	26,820
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	10,474	903	34,593	12,871	51,372	19,312	36,263	4,852	12,217	19,312	305	368	202,843

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–21.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–24 Summary of Estimated Long-term CBM Disturbance Associated with Alternative 2A

Sub-watershed	Well Pads (acres)	CMFs (acres)	Roads: Improved (acres)	Roads: Two-track (acres)	Poly Pipeline: 2–3-inch (acres)	Poly Pipeline: 12-inch (acres)	Water Handling Facilities[1] (acres)	Compressor Discharge Pipelines: Recip.[2] (acres)	Compressor Discharge Pipelines: Booster[3] (acres)	Power Line: Overhead (acres)	Compressor Stations: Recip. (acres)	Compressor Stations: Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	259	24	1,542	520	0	0	3,133	0	0	261	10	12	5,760
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,897	174	11,635	3,639	0	0	17,165	0	0	1,819	175	232	36,736
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	0	234	88	0	0	46	0	0	44	5	4	424
Crazy Woman Creek	292	27	2,374	824	0	0	3,460	0	0	411	25	24	7,437
Clear Creek	376	35	2,363	908	0	0	4,447	0	0	454	10	18	8,610
Middle Powder River	96	9	682	188	0	0	891	0	0	94	5	6	1,971
Little Powder River	204	19	2,548	1,058	0	0	1,730	0	0	529	15	12	6,114
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	164	15	7,703	3,683	0	0	1,093	0	0	1,841	20	14	14,534
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	53	5	812	166	0	0	354	0	0	83	10	6	1,490
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	593	55	4,701	1,798	0	0	3,944	0	0	901	30	40	12,061
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	3,937	363	34,593	12,871	0	0	36,263	0	0	6,437	305	368	95,138

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2-21.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions

Source: BLM 2001e

Table 2–25 Summary of Estimated Short-term CBM Disturbance Associated with Alternative 2B

Sub-watershed	Well Pads (acres)	CMFs (acres)	Roads: Improved (acres)	Roads: Two-track (acres)	Poly Pipeline: 2–3-inch (acres)	Poly Pipeline: 12-inch (acres)	Water Handling Facilities[1] (acres)	Compressor Discharge Pipelines: Recip.[2] (acres)	Compressor Discharge Pipelines: Booster[3] (acres)	Power Line: Overhead (acres)	Compressor Stations: Recip. (acres)	Compressor Stations: Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	631	59	1,542	520	2,075	782	2,718	248	727	782	10	12	10,106
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	4,978	435	11,635	3,639	14,529	5,458	15,553	2,408	6,327	5,458	175	232	70,827
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	11	1	234	88	350	132	43	24	121	132	5	4	1,145
Crazy Woman Creek	773	67	2,374	824	3,288	1,234	3,066	364	1,187	1,234	25	24	14,460
Clear Creek	1,010	86	2,363	908	3,623	1,362	3,847	320	778	1,362	10	18	15,687
Middle Powder River	238	22	682	188	752	283	848	206	267	283	5	6	3,780
Little Powder River	534	47	2,548	1,058	4,222	1,586	1,404	327	485	1,586	15	12	13,824
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	474	38	7,703	3,683	14,694	5,524	929	191	417	5,524	20	14	39,211
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	160	12	812	166	662	249	301	291	455	249	10	6	3,373
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	1,664	136	4,701	1,798	7,176	2,702	3,944	473	1,455	2,702	30	40	26,820
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	10,474	903	35,593	12,871	51,372	19,312	32,653	4,852	12,217	19,312	305	368	199,233

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–22.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–26 Summary of Estimated Long-term CBM Disturbance Associated with Alternative 2B

			Roads		Poly Pipeline			Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Water Handling Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	259	24	1,542	520	0	0	2,718	0	0	261	10	12	5,345
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,897	174	11,635	3,639	0	0	15,553	0	0	1,819	175	232	35,124
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	0	234	88	0	0	43	0	0	44	5	4	421
Crazy Woman Creek	292	27	2,374	824	0	0	3,066	0	0	411	25	24	7,043
Clear Creek	376	35	2,363	908	0	0	3,847	0	0	454	10	18	8,010
Middle Powder River	96	9	682	188	0	0	848	0	0	94	5	6	1,929
Little Powder River	204	19	2,548	1,058	0	0	1,404	0	0	529	15	12	5,788
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	164	15	7,703	3,683	0	0	929	0	0	1,841	20	14	14,370
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	53	5	812	166	0	0	301	0	0	83	10	6	1,437
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	593	55	4,701	1,798	0	0	3,944	0	0	901	30	40	12,061
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	3,938	363	34,593	12,871	0	0	32,653	0	0	6,437	305	368	91,528

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–22.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions

Source: BLM 2001e

Table 2–27 Estimated CBM Employment Requirements for Alternative 2A

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	606	7
Infiltration Facilities	24 days/impoundment	3,091	172
Containment Impoundment	90 days/impoundment	12	3
Land Application Disposal	20 days/facility	68	10
Injection Well	6.5 days/well	305	5
Total			595
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			0
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	606	35
Infiltration Facilities	25 days/facility/year	3,091	179
Containment Impoundment	25 days/facility/year	12	1
Land Application Disposal	12 days/facility/year	68	19
Injection Well	25 days/well/year	305	16
Total			2,191
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	606	2
Infiltration Facilities	10 days/facility	3,091	55
Containment Impoundment	45 days/facility	12	1
Land Application Disposal	2 days/facility	68	1
Injection Well	2 days/well	305	1
Total			214

Note:

1. Estimates assume 300 working days per year.

Table 2–28 Estimated CBM Employment Requirements for Alternative 2B

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	7,163	16
Well Pads	1 day/pad	25,997	8
Pipelines	2 days/mile	20,846	97
Electrical Utility Lines	2 days/mile	5,311	25
Drilling and Casing	4 days/well	39,367	65
Well Completion	2 days/well	39,367	165
Compressors (Recip.)	21 days/compressor	298	15
Compressors (Booster)	3 days/compressor	1,060	7
Surface Discharge Facilities	5 days/pond	878	10
Infiltration Facilities	24 days/impoundment	2,169	121
Containment Impoundment	90 days/impoundment	37	8
Land Application Disposal	20 days/facility	72	11
Injection Well	6.5 days/well	292	4
Total			552
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	25,997	199
Pumpers			0
Wells	15 days/pad/year	25,997	245
CMFs	30 days/10 wells/year	3,936	42
General Infrastructure	12 days/pad/year	25,997	196
Office	6 days/well/year	39,367	716
Well Workover	4 days/well/year	39,367	477
Compressors (Recip.)	52 days/compressor/year	298	36
Compressors (Booster)	12 days/compressor/year	1,060	30
Surface Discharge Facilities	25 days/pond/year	878	51
Infiltration Facilities	25 days/facility/year	2,169	126
Containment Impoundment	25 days/facility/year	37	2
Land Application Disposal	12 days/facility/year	72	20
Injection Well	25 days/well/year	292	17
Total			2,157
Decommissioning/Reclamation			
Wells	2 days/well	39,367	33
Roads	2 days/mile	7,136	26
Compressors (Recip.)	20 days/compressor	298	9
Compressors (Booster)	2 days/compressor	1,060	3
Reclamation	5 days/facility	25,997	83
Surface Discharge Facilities	2 days/pond	878	3
Infiltration Facilities	10 days/facility	2,169	34
Containment Impoundment	45 days/facility	37	3
Land Application Disposal	2 days/facility	72	1
Injection Well	2 days/well	292	1
Total			196

Note:

1. Estimates assume 300 working days per year.

Alternative 3 — No Action

The No Action alternative is required by NEPA for comparison with the other alternatives analyzed in the EIS. For this analysis, the No Action alternative would not authorize additional natural gas development on federal leases within the Project Area. Drilling could continue on state and private leases. BLM and the FS assumed the pattern of spacing for CBM wells on state and private leases would remain at 80 acres. Access and pipelines across federal lands to reach the proposed state and fee wells would be granted as required by BLM's policy.

The Department of Interior's authority to implement a "No Action" alternative that precludes development by denying the process is, however, limited. An oil and gas lease grants the lessee the "right and privilege to drill for, mine, extract, remove, and dispose of all oil and gas deposits" in the lease lands, "subject to the terms and conditions incorporated in the lease" (Form 3110–2). Because the Secretary of Interior has the authority and responsibility to protect the environment within federal oil and gas leases, restrictions are imposed on the terms of the lease.

Leases within the project area contain various stipulations that address surface disturbance, surface occupancy, limited surface use and restrictions on timing. In addition, the lease stipulations provide for the imposition of conditions that the BLM and/or FS may require to protect the surface/subsurface of the leased lands and the environment. Approval of an APD could only be denied when the activity would constitute a violation of law or regulation or would cause unacceptable impacts (43 U.S.C. 1732(b); 30 U.S.C. 226(g); 43 CFR 3101.1-2).

Development of Coal Bed Methane

Under this alternative, development of non-federal CBM would continue to occur on non-federal minerals. The agencies assumed that development of fee and state minerals would occur along the same overall schedule as for Alternative 1.

As a result, the Companies would drill 15,504 new CBM wells between 2002 and 2011 (Table 2–29). These wells would be in addition to the 12,024 CBM wells already permitted or drilled on federal, state, and private lands. Thus, 27,528 CBM wells would be developed under this alternative by 2011 (Table 2–29).

As under Alternatives 1 and 2, some of the new CBM wells would be drilled from the same well pads. Thus, the number of pads constructed would be less than the number of wells drilled. The Companies would construct 10,572 new well pads between 2002 and 2011 (Table 2–30). With the 9,595 pads constructed or permitted for construction before 2002, this alternative would result in 20,167 well pads by 2011 (Table 2–30).

Because fewer new wells would be drilled and pads constructed, the number of facilities constructed also would be smaller than under the Proposed Action (Table 2–31). Furthermore, the overall short-term and long-term disturbances associated with this alternative would be less than would occur with implementation of Alternatives 1 or 2 (Table 2–32 and Table 2–33).

Table 2–29 Distribution of CBM Wells by Sub-watershed — Alternative 3

Sub-watershed	Number of CBM Wells Pre-2002	2002–2011	Total
Little Bighorn River	0	0	0
Upper Tongue River	819	2,164	2,983
Middle Fork Powder River	0	0	0
North Fork Powder River	0	0	0
Upper Powder River	2,808	4,445	7,253
South Fork Powder River	0	0	0
Salt Creek	0	19	19
Crazy Woman Creek	150	949	1,099
Clear Creek	389	2,502	2,891
Middle Powder River	727	201	928
Little Powder River	1,814	964	2,778
Little Missouri River	0	0	0
Antelope Creek	251	604	855
Dry Fork Cheyenne River	0	0	0
Upper Cheyenne River	401	256	657
Lightning Creek	0	0	0
Upper Belle Fourche River	4,659	3,400	8,059
Middle North Platte River	6	0	6
Total	12,024	15,504	27,528

Source: BLM 2001e

With fewer wells overall, implementation of this alternative also would result in smaller amounts of produced water and gas. Table 2–34 and Table 2–35 show the amounts of water and gas projected for this alternative. However, it is possible that more wells would result if the companies determined that the federal mineral acreage was economic to drain at 40 acre spacing and the companies could request the WOGCC to down space to 40 acres around federal mineral acreage.

Drilling and Construction of Facilities

Electrical Power Utilities

Based on projected power demands, it is anticipated that the Companies would require 0.5 MW per day to transport 3 bcf of natural gas per day using gas-fired compression. Based on this power demand, the maximum power requirement would be 0.6 MW per day.

Table 2–30 Distribution of CBM Well Pads by Sub-watershed — Alternative 3

Sub-watershed	Number of CBM Well Pads		
	Pre-2002	2002–2011	Total
Little Bighorn River	0	0	0
Upper Tongue River	397	980	1,377
Middle Fork Powder River	0	0	0
North Fork Powder River	0	0	0
Upper Powder River	2,254	2,847	5,101
South Fork Powder River	0	0	0
Salt Creek	0	19	19
Crazy Woman Creek	63	638	701
Clear Creek	231	1,745	1,976
Middle Powder River	438	97	535
Little Powder River	1,301	655	1,956
Little Missouri River	0	0	0
Antelope Creek	249	527	776
Dry Fork Cheyenne River	0	0	0
Upper Cheyenne River	390	256	646
Lightning Creek	0	0	0
Upper Belle Fourche River	4,266	2,808	7,074
Middle North Platte River	6	0	6
Total	9,595	10,572	20,167

Source: BLM 2001e

Under this alternative, three-phase 24.9-kV distribution lines would connect wells and compressor facilities with the existing transmission and distribution system in the Project Area. Electricity would be routed to compressor stations and CMFs above ground on poles generally located along the access roads or on additional rights-of-way (30 feet wide) across open land. Between the CMFs and wells, the secondary electric service power lines (480 volt) would be buried in the same trenches as the pipelines to gather gas and produced water. The installation and power would be provided by the utility company that supplies these services. The power lines would be constructed after access roads have been developed and would coincide with completion of well drilling. The power lines would be designed and constructed according to the Avian Power Line Interaction Committee's (1996) guidelines for the prevention of electrocution of raptors.

The aboveground power lines would be constructed using tracked and wheeled equipment. Holes for the poles would be located so that they do not disturb existing sensitive vegetation and would be excavated to a depth of 6 to 8 feet. Poles and other structural components would be transported to the construction site, where they would be assembled and then erected by a boom truck.

Table 2–31 Summary of New Facilities that Comprise Alternative 3

Sub-watershed	Well[3] Pads	Roads: Improved (miles)	Roads: Two-track (miles)	Poly Pipeline: 2–3-inch (miles)	Poly Pipeline: 12-inch (miles)	Steel Pipeline: 12-inch (miles)	Electrical Line: Overhead (miles)	Recip Compressors[1] (units)	Recip Compressors[1] (horsepower)	Booster Compressors[2] (units)	Booster Compressors[2] (horsepower)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	979	288	369	491	185	80	185	9	14,850	31	10,850
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	2,847	558	722	961	361	158	361	48	79,200	150	52,500
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	19	24	37	49	19	5	19	0	0	3	1,050
Crazy Woman Creek	638	157	229	304	114	38	114	6	9,900	24	8,400
Clear Creek	1,746	335	506	673	253	68	253	8	13,200	37	12,950
Middle Powder River	97	16	32	43	16	0	16	0	0	0	0
Little Powder River	655	256	452	601	226	22	226	3	4,950	9	3,150
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	527	564	1,104	1,468	552	10	552	0	0	10	3,500
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	256	74	66	87	33	24	33	2	3,300	4	1,400
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	2,808	592	871	1,159	436	110	436	21	34,650	82	28,700
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0
Total	10,572	2,864	4,387	5,836	2,194	515	2,194	97	160,050	350	122,500

Notes:

1. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
2. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
3. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–32 Summary of Estimated Short-term Disturbance Associated with Alternative 3

			Roads		Poly Pipeline		Water Handling	Compressor Discharge Pipelines		Power Line	Compressor Stations		
Sub-watershed	Well Pads (acres)	CMFs (acres)	Improved (acres)	Two-track (acres)	2–3-inch (acres)	12-inch (acres)	Facilities[1] (acres)	Recip.[2] (acres)	Booster[3] (acres)	Overhead (acres)	Recip. (acres)	Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	531	50	1,396	448	1,785	672	2,007	248	727	672	10	12	8,559
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	1,174	102	2,706	875	3,493	1,312	2,462	550	1,364	1,312	40	50	15,440
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	6	0	114	45	180	68	14	0	61	68	0	2	557
Crazy Woman Creek	254	22	763	277	1,106	415	626	73	391	415	5	8	4,354
Clear Creek	675	57	1,623	613	2,446	919	2,351	213	605	919	10	14	10,447
Middle Powder River	50	5	79	39	157	59	145	0	0	59	0	0	593
Little Powder River	259	22	1,240	548	2,186	821	690	109	162	821	5	4	6,866
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	174	14	2,735	1,338	5,337	2,006	431	0	119	2,006	0	4	14,164
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	77	6	358	80	318	120	186	145	152	120	5	2	1,568
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	961	78	2,872	1,055	4,213	1,586	2,771	315	1,018	1,586	20	28	16,504
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	4,159	356	13,886	5,317	21,221	7,980	11,683	1,655	4,598	7,930	95	124	79,052

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–33 Summary of Estimated Long-term Disturbance Associated with Alternative 3

Sub-watershed	Well Pads (acres)	CMFs (acres)	Roads: Improved (acres)	Roads: Two-track (acres)	Poly Pipeline: 2–3-inch (acres)	Poly Pipeline: 12-inch (acres)	Water Handling Facilities[1] (acres)	Compressor Discharge Pipelines: Recip.[2] (acres)	Compressor Discharge Pipelines: Booster[3] (acres)	Power Line: Overhead (acres)	Compressor Stations: Recip. (acres)	Compressor Stations: Booster (acres)	Total[4] (acres)
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	216	20	1,396	448	0	0	2,007	0	0	224	10	12	4,333
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	445	41	2,706	875	0	0	2,462	0	0	437	40	50	7,056
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	2	0	114	45	0	0	14	0	0	23	0	2	200
Crazy Woman Creek	95	9	763	277	0	0	626	0	0	138	5	8	1,921
Clear Creek	250	23	1,623	613	0	0	2,351	0	0	306	10	14	5,191
Middle Powder River	20	2	79	39	0	0	145	0	0	20	0	0	305
Little Powder River	96	9	1,240	548	0	0	690	0	0	274	5	4	2,865
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	60	6	2,735	1,338	0	0	431	0	0	669	0	4	5,243
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	26	2	358	80	0	0	186	0	0	40	5	2	699
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	340	31	2,872	1,055	0	0	2,771	0	0	529	20	28	7,646
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0
Total[3]	1,551	143	13,886	5,317	0	0	11,683	0	0	2,660	95	124	35,458

Notes:

1. Disturbance includes the areal extent of direct discharge facilities, containment reservoirs, land application facilities, and injection wells. The ratios of water handling facilities applied to each sub-watershed are shown on Table 2–9.
2. Reciprocating (Recip.) compressors increase the compression of natural gas for delivery to high-compression transmission pipelines. Each station would consist of one to six recip compressors, depending on the volume of gas being delivered to the station.
3. Booster compressors enhance the flow of gas from the wells to the recip compressors. Each station would consist of one to six booster compressors, depending on the volume of gas being delivered to the station.
4. Total may not match precisely with the value obtained by adding unit numbers because of rounding conventions.

Source: BLM 2001e

Table 2–34 Projected Amount of Water Produced from CBM Wells under Alternative 3

Sub-watershed	Water Produced (acre-feet)[1]																
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Little Bighorn River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	10,279	15,847	19,119	20,187	20,393	17,701	17,623	13,310	12,471	12,585	6,950	3,785	2,018	1,032	473	176	173,949
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Powder River	45,850	54,608	58,124	60,210	60,054	53,068	42,195	19,954	13,226	9,671	5,170	2,646	1,167	480	215	80	426,718
South Fork Powder River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Salt Creek	184	104	85	179	259	146	82	43	24	13	5	0	0	0	0	0	1,124
Crazy Woman Creek	4,429	5,971	6,893	7,806	7,664	7,348	6,548	4,452	4,350	4,396	2,418	1,315	687	346	174	64	64,861
Clear Creek	9,172	14,731	17,758	18,176	18,858	17,907	16,772	13,780	13,377	13,941	7,738	4,235	2,265	1,148	556	209	170,623
Middle Powder River	7,284	7,298	7,883	8,634	7,886	5,347	5,181	1,615	961	1,055	574	313	168	81	32	17	54,329
Little Powder River	17,026	18,231	18,119	18,462	16,931	13,217	13,897	3,479	3,679	3,124	1,899	1,132	677	356	186	55	130,470
Little Missouri River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Antelope Creek	10,536	10,871	10,596	10,803	10,323	9,057	6,433	2,311	1,348	1,074	378	132	45	14	4	1	73,926
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	6,415	6,870	6,486	6,712	6,744	5,213	4,266	870	806	451	159	55	19	6	2	0	45,074
Lightning Creek	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	47,247	53,736	58,399	61,750	61,591	58,656	52,057	27,701	21,615	17,323	11,694	7,466	4,143	1,836	991	463	486,668
Middle North Platte River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	158,422	188,267	203,462	212,919	210,703	187,660	165,054	87,515	71,857	63,633	36,985	21,079	11,189	5,299	2,633	1,065	1,627,742

Note:

1. Volumes shown include produced water from pre-2002 wells as well as the new CBM wells.

Sources: BLM 2001c and Meyer 2002b.

Table 2–35 Projected Amounts of Natural Gas Produced from CBM Wells under Alternative 3

	Total Cubic Feet of Methane Produced per Day by Year (in mmcf)									
Sub-watershed	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Little Bighorn River	0	0	0	0	0	0	0	0	0	0
Upper Tongue River	18	30	47	60	70	74	76	77	77	77
Middle Fork Powder River	0	0	0	0	0	0	0	0	0	0
North Fork Powder River	0	0	0	0	0	0	0	0	0	0
Upper Powder River	252	399	481	534	542	538	520	446	308	192
South Fork Powder River	0	0	0	0	0	0	0	0	0	0
Salt Creek	4	6	7	8	8	7	7	6	4	2
Crazy Woman Creek	31	50	63	72	75	75	74	66	51	38
Clear Creek	37	58	76	89	97	101	103	102	97	93
Middle Powder River	2	3	4	5	5	6	6	6	6	6
Little Powder River	26	39	45	49	50	50	51	49	43	38
Little Missouri River	0	0	0	0	0	0	0	0	0	0
Antelope Creek	29	44	50	54	54	53	52	45	33	23
Dry Fork Cheyenne River	0	0	0	0	0	0	0	0	0	0
Upper Cheyenne River	15	22	25	27	27	27	27	27	23	20
Lightning Creek	0	0	0	0	0	0	0	0	0	0
Upper Belle Fourche River	161	228	252	264	261	260	257	233	180	132
Middle North Platte River	0	0	0	0	0	0	0	0	0	0
Total	575	879	1,050	1,162	1,189	1,191	1,173	1,057	822	621

Source: BLM 2001e

The locations of the poles could be moved within the 30-foot wide right-of-way (ROW) if topography or impacts to cultural, vegetative, or wildlife resources are identified at the site of the structure. In areas of thick vegetation or where vegetation may impede the performance of the active line, vegetation would be cleared, typically with hand-held equipment. BLM would be consulted before any vegetation is removed where areas of sensitive plant resources are known to occur.

All aboveground electric lines typically would be installed on 35-foot tall poles. Poles would be required approximately every 300 feet. Approximately 2,195 miles of aboveground power lines would be installed in the Project Area (Table 2–31). The short-term disturbance for these lines would be 7,978 acres (Table 2–32).

Workforce Requirements

Most of the active workforce involved in developing Alternative 3 would be occupied in construction-related activities. After roads and well pads are constructed, pipelines and utility lines are installed, and wells are drilled and completed, minimal personnel would be required to operate in the field. Table 2–36 shows the estimated employment requirements for the construction, operation, and reclamation of the project under Alternative 3.

Construction Resource Requirements

Construction of the project would require a variety of materials and equipment. The primary materials would be water, sand, and gravel. Additionally, small amounts of chemicals would be required. Machinery needed for construction would include heavy equipment (bulldozers, graders, track hoes, trenchers, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, pipelines, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct Alternative 3 is expected to be 2,765 acre-feet (Table 2–37). This water would be obtained from local sources.

Non-CBM Development

As with the CBM wells, development of non-CBM wells would continue to occur on non-federal minerals. The agencies assumed that development would be proportional to the areal extent of private and state minerals present in the Project Area. Table 2–38 shows the projected distribution of non-CBM wells.

Surface disturbance for a typical non-CBM well includes 2.25 acres for the well pad and 0.5 acres for a ⅓-mile bladed road, for a total of 2.75 acres disturbed for drilling operations. Part of the well pad area is reclaimed for production operations, and the entire area of disturbance is reclaimed when the well is plugged and abandoned.

Table 2–36 Estimated CBM Employment Requirements for Alternative 3

Work Category	Time Requirements per Unit	Number of Units	Peak Number of Workers per Year[1]
Construction and Installation			
Access Roads	0.5 day/mile	2,864	23
Well Pads	1 day/pad	10,572	2
Pipelines	2 days/mile	8,546	21
Electrical Utility Lines	2 days/mile	2,195	7
Drilling and Casing	4 days/well	15,504	26
Well Completion	2 days/well	15,504	47
Compressors (Recip.)	21 days/compressor	350	12
Compressors (Booster)	3 days/compressor	97	12
Surface Discharge Facilities	5 days/pond	419	4
Infiltration Facilities	24 days/impoundment	638	26
Containment Impoundment	90 days/impoundment	24	4
Land Application Disposal	20 days/facility	13	1
Injection Well	6.5 days/well	147	2
Total			187
Operation and Maintenance			
Road/Pad Maintenance	12 days/pad/year	10,572	58
Pumpers			0
Wells	15 days/pad/year	10,572	696
CMFs	30 days/10 wells/year	98	60
General Infrastructure	12 days/pad/year	10,572	556
Office	6 days/well/year	15,504	278
Well Workover	4 days/well/year	15,504	185
Compressors (Recip.)	52 days/compressor/year	350	31
Compressors (Booster)	12 days/compressor/year	97	2
Surface Discharge Facilities	25 days/pond/year	419	18
Infiltration Facilities	25 days/facility/year	638	27
Containment Impoundment	25 days/facility/year	24	1
Land Application Disposal	12 days/facility/year	13	3
Injection Well	25 days/well/year	147	6
Total			1,921
Decommissioning/Reclamation			
Wells	2 days/well	15,504	34
Roads	2 days/mile	2,864	1
Compressors (Recip.)	20 days/compressor	350	1
Compressors (Booster)	2 days/compressor	97	1
Reclamation	5 days/facility	10,572	84
Surface Discharge Facilities	2 days/pond	419	1
Infiltration Facilities	10 days/facility	638	1
Containment Impoundment	45 days/facility	24	1
Land Application Disposal	2 days/facility	13	1
Injection Well	2 days/well	147	1
Total			126

Note:

1. Estimates assume 300 working days per year.

Table 2–37 Summary of Requirements for Sand, Gravel, and Water under Alternative 3

Facility	Amount	Unit	Rate	Total Volume
Sand and Gravel				
Improved roads	2,864	miles	1,173 yd^3/mile	3,359,472
CMFs	1,550	CMFs	30 yd^3/CMF	46,512
Compressors	81	stations	1,100 yd3/station	89,100
Total (yd^3)				3,495,084
Water				
Roads	7,252	miles	0.1 acre-feet/mile	725
Pipelines	515	miles	0.04 acre-feet/mile	21
Well drilling	15,504	wells	0.08 acre-feet/well	1,240
Well completion	15,504	wells	0.05 acre-feet/well	775
Compressors	447	stations	0.01 acre-feet/compressor	4
Total (acre-feet)				2,765

Table 2–38 Projected Distribution of Non-CBM Wells under Alternative 3

	Potential for Oil and Gas				
Sub-watershed	Very Low	Low	Moderate	High	Total
Buffalo Field Office Area					
Little Bighorn River	5	0	0	0	5
Upper Tongue River	8	26	0	0	34
Middle Fork Powder River	6	2	0	0	8
North Fork Powder River	0	0	0	0	0
Upper Powder River	0	8	111	0	119
South Fork Powder River	3	0	0	0	3
Salt Creek	0	1	5	0	6
Crazy Woman Creek	1	7	0	0	8
Clear Creek	0	20	0	0	20
Middle Powder River	0	1	25	13	39
Little Powder River	0	0	76	472	548
Little Missouri River	0	0	0	33	33
Antelope Creek	0	0	24	0	24
Upper Cheyenne River	0	0	21	0	21
Upper Belle Fourche River	0	3	137	220	360
Total	23	68	399	738	1,228
Casper Field Office Area					
Converse County					74
Total					1,302

As shown on Table 2–39, 3,581 surface acres of the Project Area may be disturbed by construction of non-CBM wells. Most of this disturbance would occur in three watersheds: the Little Powder River, Upper Belle Fourche River, and Upper Powder River. After the wells are operational and partial reclamation has occurred, long-term disturbance would encompass about 85 percent of the original area disturbed.

Non-CBM development also would require a workforce involved in construction-related activities. Again, after roads and well pads are constructed and wells are drilled and completed, minimal personnel would be required to operate in the field. Table 2–40 shows the estimated employment requirements for the non-CBM wells.

Alternatives Considered but Eliminated from Detailed Analysis

Several potential alternatives were considered for this analysis but were eliminated from detailed study for various reasons. These alternatives are listed below, and the reasons they were excluded from further consideration are described.

Alternative Considered: Return all produced water to aquifers

Reasons Considered: This alternative was specifically developed to respond to issues about effects to aquifers and soils and the quantity and quality of surface water in and downstream of the Project Area. Under this alternative, the Companies would capture and actively return produced water to aquifers. Methods for accomplishing return include storage and retrieval wells, infiltration pits, land application (for example, spreaders and sprinklers), infiltration at clinker zones, and leach fields.

Reasons Dropped: The technical feasibility of an all-injection alternative appears to be limited. The nature of the groundwater flow systems and water chemistry in the PRB are not well understood, making it difficult to analyze the potential effects of widespread injection. Formations that are potential zones for injection may have limited capacity to accept the large volumes of water that would be injected. Existing groundwater in some potential zones for injection likely is unsuitable for mixing with water produced from CBM wells, if future retrieval of injected water for beneficial use is planned. Injection into some formations would degrade the quality of the water produced from CBM wells.

Table 2–39 Projected Maximum Disturbance Caused by Non-CBM Wells Under Alternative 3

	Areal Extent of Disturbance	
Sub-watershed	Short-term (acres)	Long-term (acres)
Buffalo Field Office Area and TBNG		
Little Bighorn River	14	12
Upper Tongue River	94	80
Middle Fork Powder River	22	19
North Fork Powder River	0	0
Upper Powder River	327	280
South Fork Powder River	8	7
Salt Creek	16	14
Crazy Woman Creek	22	19
Clear Creek	55	47
Middle Powder River	107	92
Little Powder River	1,507	1,288
Little Missouri River	91	78
Antelope Creek	66	56
Upper Cheyenne River	58	49
Upper Belle Fourche River	990	846
Total	3,377	2,886
Casper Field Office Area		
Converse County	204	174
Total	3,581	3,060

Note:

Maximum disturbance is based on 2.75 acres per well for short-term disturbance and 2 acres per well for long-term disturbance.

Table 2–40 Estimated Non-CBM Employment Requirements for Alternative 3

Work Category	Time Requirements per Unit	Number of Units	Average Number of Workers per Day
Construction and Installation			
Access Roads	0.5 day/mile	3,200	1
Well Pads	1 day/pad	3,200	1
Drilling and Casing	4 days/well	3,200	27
Well Completion	2 days/well	3,200	13
Total			42
Operation and Maintenance			
Road/Pad Maintenance	1 days/well	1,600	6
Pumpers			0
Wells	15 days/well/year	1,600	8
General Infrastructure	12 days/well/year	1,600	6
Office	6 days/well	1,600	3
Well Workover	4 days/well	1,600	2
Total			25
Decommissioning/Reclamation			
Wells	2 days/well	1,600	21
Roads	2 days/mile	1,600	2
Total			23

The economic feasibility of an all-injection alternative is unproven. To date, injection has been tested, but has not been shown to be economically viable in the PRB because of its high cost and uncertain success in disposing of all produced water over the life of a group of CBM wells. The high costs associated with injection would not be reasonable unless disposal of water by this method would be successful and the costs of this method would not cause development of CBM to become uneconomical. Development of CBM using injection as the only water handling method would eliminate the current beneficial use of water discharged from CBM wells, further reducing the economic feasibility of this alternative.

The ability of the BLM and FS to implement this alternative is limited. BLM and FS could not require the Companies to implement this alternative. Much of the Project Area involves non-federal minerals and non-federal surface, and BLM and FS have no jurisdiction. The alternatives considered in detail involve returning at least a portion of the produced water to aquifers.

Alternative Considered: Capture and treat produced water for additional beneficial uses.

Reasons Considered: Under this alternative, the Companies would capture the produced water, treat it, and make it available for additional beneficial uses. These uses include stock watering, wildlife habitat (aquatic, wetlands, and riparian), recreational opportunities (such as hunting waterfowl), and irrigation. In addition to responding to the issues about effects to aquifers and soils and the quantity and quality of surface water in and downstream of the Project Area, this alternative was developed to respond to effects on terrestrial wildlife, aquatic wildlife, and recreational opportunities.

Reasons Dropped: This alternative technically would not be feasible over the long term. Each CBM well is expected to produce water for a maximum of 7 years, with a peak in production occurring during the initial few years. Any additional beneficial uses provided if the agencies required the Companies to treat the produced water and make

	it available would essentially be relatively short term. Once the produced water from specific wells diminishes, the beneficial uses supported also would diminish. Thus, beneficial uses also would be short term wherever they would occur.
Alternative Considered:	Staged rate or phased development.
Reasons Considered:	This alternative was developed in response to a variety of the issues raised during scoping, including concerns about the volume of water discharged to local drainages. Staged or phased development was presented to BLM during scoping in several ways. First, the number of rigs operating in the Project Area could be controlled and leases would be developed in stages. Second, the Companies would be allowed to develop production in one geographic area at a time and when complete, move on to another area. Lastly, corridors could be left undeveloped to allow for wildlife movement.
Reasons Dropped:	The State of Wyoming or private parties own much of the minerals and surface in the Project Area and the BLM and FS have no legal authority to direct the Companies in developing these leases. Additionally, the BLM and FS have a legal obligation to ensure that leased federal minerals are fully developed and that production occurring on non-federal leases does not drain federal minerals. This alternative is not reasonable in the case of existing leases because each lessee has an investment-backed expectation that its APDs will be considered in a timely manner and approved absent unacceptable site-specific impacts (see the Supreme Court decision in *Mobil Oil Exploration and Producing Southeast, Inc. v. United States*, 530 U.S. 604, 620 [2000] which found a breach of contract when the Minerals Management Service, pursuant to a later adopted statute, would not review and make a timely decision on development plans per the regulatory scheme in place at lease issuance.) In addition, the Mineral Leasing Act and 43 CFR 3100 require maximum ultimate economic recovery of oil and gas from leased lands. In light of the broad geographic distribution of leases in the PRB, phased development in any fashion would not allow compliance with the above requirements.

Alternative Considered:	No action on all lands.
Reasons Considered:	This alternative was considered as a true No Action alternative under NEPA. Under this alternative, no further drilling or development of oil or gas wells would occur anywhere within the Project Area.
Reasons Dropped:	This alternative was eliminated from detailed consideration because it was not at all feasible. Development of fee and state minerals, particularly any already leased, would continue regardless of the decisions by BLM and FS. Because development of fee and state minerals undoubtedly will occur, BLM and FS decided a No Action alternative that involved development of fee and state minerals without the development of federal minerals would more closely resemble the actual situation of the BLM and FS denying any further development of CBM from federal minerals.

Alternative Considered:	Discharge produced water to the surface, but ensure that water quality at the Wyoming-Montana border does not change enough to adversely affect the uses of water at and downstream of the border.
Reasons Considered:	This alternative was considered as a means to address the State of Montana's concerns about the quality of surface water that enters the state. Under this alternative, the quality and quantity of discharges of produced water would be monitored to ensure that any changes in water quality at the state line would be insufficient to affect downstream uses of that water in Montana.
Reasons Dropped:	The Montana and Wyoming Powder River Interim Water Quality Criteria Memorandum of Cooperation essentially accomplished this alternative. If the monitoring conducted under this agreement suggests that produced water discharging into the rivers and subsequently into Montana may not meet the interim criteria, the Companies would be obliged to discontinue discharging the produced water that causes noncompliance with the MOC. The thresholds or criteria identified in the agreement are well below levels that would interfere with the existing uses of the water. Therefore, discharging the

	produced water would be discontinued before it would interfere with any downstream uses.
Alternative Considered:	Several environmental groups developed an alternative they identify as the "Conserving Wyoming's Heritage Alternative." This alternatives is based primarily on phased development, alternative and innovative technologies, adaptive management, the "reopening" of permits, landowner protections, injection and treatment of produced water, and minimizing adverse effects to the full range of resources present in the Project Area.
Reasons Considered:	This alternative was considered in response to comments submitted on the DEIS.
Reasons Dropped:	Considered as a whole, this alternative was unreasonable because it could not be implemented. A foundational element of the alternative was phased or staged development, which BLM and the FS have no legal means to implement, as discussed in the staged development alternative above. Another foundational element of this alternative was injection of water produced from CBM wells. The reasons this element was considered unreasonable are described above for the alternative of returning all produced water to aquifers. Finally, the other elements of the alternative (for example, injection) were already incorporated into the alternatives considered in detail.

Impact and Mitigation Monitoring and Reporting

Appendix D of this EIS contains a framework for a Mitigation Monitoring and Reporting Plan (MMRP) that would be adopted for this project. This framework was developed to:

- Verify implementation of mitigation measures adopted in the ROD;
- Measure the success rate of those mitigation measures;
- Make appropriate modifications to mitigation based on actual performance;
- Allow for peer review of mitigation and monitoring results; and
- Provide feedback to the interested public.

Summary of Alternatives and Environmental Consequences

The following tables summarize the alternatives considered in detail and the likely environmental consequences of each. Table 2–41 contains the summary of alternatives. This table contrasts the four alternatives in terms of their physical characteristics. The matrix presented in Table 2–42 provides a comparison summary of the effects to the various environmental resources that would occur by implementing each of the four alternatives for the Powder River Basin Oil and Gas Project.

Agency-Preferred Alternative

BLM's preferred alternative is a combination of Alternative 2A and Alternative 1. BLM prefers Alternative 2A for all parts of the project except the use of electric booster compressors. Thus, the portion of Alternative 1 preferred by BLM is the natural gas-fired compressors. The following discussion presents BLM's rationale for these preferences.

Although implementation of Alternative 2A for water may disturb more land and cost more than Alternative 1, BLM prefers Alternative 2A, emphasis on infiltration to reduce or mitigate impacts to water because:

1. Alternative 2A involves separate water management strategies for each sub-watershed that align with WDEQ's current approach to permitting.
2. The water management plans required under Alternative 2A would minimize the volume of water that reaches the main-stems in the sub-watersheds of the Little Powder River, Powder River, and Tongue River. This would reduce the potential for adverse effects on the water quality in the sub-basins most sensitive to potential changes in water quality, and most heavily used by irrigators.
3. Alternative 2A would maximize local beneficial use of the produced water rather than discharging the water downstream where the state and surface owners get no benefit from this resource.
4. Alternative 2A maximizes infiltration and storage of the produced water into the shallow aquifers of Wyoming, rather than having this resource pumped into surface waters that leave the state. This infiltration also would help with deeper aquifer recharge in the PRB.
5. Encourages treatment of produced water, where feasible and practicable.

BLM's preferred alternative retains the action as proposed with respect to the use of natural gas-fired compressors.

For Alternative 1, (natural gas fired compression engines) the analysis documents that the benefits to air quality and visibility from electrifying half or all of the booster compressors is negligible and would be insufficient to justify the additional costs of requiring the Companies to use electric booster compressors. An additional factor that led to this decision is the need for new power generation to provide electricity to these compressors. Also, the Companies would build relatively few booster compressors on surface owned by the Federal government and BLM does not have the ability to require electrification of compressors constructed off Federal surface. The State of Wyoming is responsible for permitting the compressors. The need for electrical compression as a condition of approval is best developed based on a case by case review of the emissions permit applications to be issued by the WDEQ. Choosing this option as the preferred alternative for air does not preclude the WDEQ from requiring the use of electric compression if determined to be necessary during its permitting process. This gives the WDEQ maximum flexibility to permit facilities in the most economical way that complies with applicable national and state air quality standards.

BLM and the State of Wyoming are committed to preventing any exceedence of air quality standards. In response to comments on the DEIS, BLM has used the same model for air quality impacts as the Montana BLM, and has gathered new data since the draft. Although the new model shows that there is a potential for greater air impacts than in the DEIS, the majority of these additional impacts result from other activities that are ongoing within the Project Area and not the project itself. BLM and the state will continue to monitor and implement adaptive management strategies at the permitting stage to assure that air quality in the region continues to meet federal and state goals for PM_{10}, HAPS, visibility impairment, and atmospheric deposition.

Table 2–41 Summary Comparison of Alternatives Considered in Detail

Parameter	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
New CBM Facilities				
Number of Wells				
Federal ownership	23,863	23,863	23,863	0
Non-federal ownership	15,504	15,504	15,504	15,504
Total	39,367	39,367	39,367	15,504
Number of Well Pads				
Federal ownership	15,425	15,425	15,425	0
Non-federal ownership	10,572	10,572	10,572	10,572
Total	25,997	25,997	25,997	10,572
Roads (miles)				
Improved	7,135	7,135	7,135	2,864
Two-track	10,619	10,619	10,619	4,387
Pipeline (miles)				
2–3-inch poly	14,127	14,127	14,127	5,836
12-inch poly	5,311	5,311	5,311	2,194
12-inch steel	1,408	1,408	1,408	516
Overhead Electric Line (miles)	5,311	5,311	5,311	2,194
Compressors				
Number of booster units	1,060	1,060	1,060	350
Number of booster stations	184	184	184	62
Total horsepower of booster units	371,000	371,000	371,000	122,500
Number of reciprocating units	298	298	298	97
Number of reciprocating stations	61	61	61	19
Total horsepower of reciprocating units	491,700	491,700	491,700	160,050
Water Handling Facilities				
Analyzed number of surface discharge facilities	1,217	606	878	419
Analyzed number of infiltration facilities	1,301	3,091	2,169	638
Analyzed number of containment impoundments	57	12	37	24
Analyzed number of injection wells	323	305	292	147
Analyzed number of LAD facilities	28	68	72	13
Projected Short-term Disturbance (acres)	193,589	202,843	199,233	79,052
Projected Long-term Disturbance (acres)	85,884	95,138	91,528	35,458
Workforce Requirements				
Construction and installation (peak no. of employees)	505	595	552	187
Operation and maintenance (peak no. of employees)	1,918	2,191	2,157	1,921
Reclamation and abandonment (peak no. of employees)	189	214	196	126
New non-CBM Facilities				
Number of new wells				
Federal ownership	1,791	1,791	1,791	0
Non-federal ownership	1,409	1,409	1,409	1,409
Total	3,200	3,200	3,200	1,409
Projected short-term disturbance (acres)	8,800	8,800	8,800	3,581
Projected long-term disturbance (acres)	7,520	7,520	7,520	3,060
Workforce Requirements				
Construction and installation (peak no. of employees)	42	42	42	42
Operation and maintenance (peak no. of employees)	25	25	25	25
Reclamation and abandonment (peak no. of employees)	23	23	23	23
Total Projected Disturbance (CBM and non-CBM)				
Projected short-term disturbance (acres)	202,389	211,643	208,033	82,633
Projected long-term disturbance (acres)	93,404	102,658	99,048	38,518

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	2A	2B	3
Groundwater				
Removal	Remove 3,069,665 acre-feet during the life of the project, about 0.2 percent of the recoverable groundwater stored within the Wasatch and Fort Union Formations	Same as Alternative 1	Same as Alternative 1	Remove 1,627,742 acre-feet during the life of the project, about 0.1 percent of the recoverable groundwater stored within the Wasatch and Fort Union Formations.
Maximum Drawdown				
Fort Union Formation	Up to 800 feet	Same as Alternative 1	Same as Alternative 1	Similar to Alternative 1. However, the areal extent of the 25-foot drawdown contour would tend to decrease in areas where large concentrations of federal wells were projected to be drilled under Alternative 1, due to non-development under Alternative 3.
Deep Wasatch Sands	Deep Wasatch Sands within 100 feet of the coal zone could experience drawdowns that are 5 to 10 percent of the projected drawdown in the coal.	Same as Alternative 1	Same as Alternative 1	Similar to Alternative 1. However, in areas that would have had very high concentrations of federal wells under Alternative 1, the extent of drawdown within the Wasatch Sands would be less, because of non-development under Alternative 3.
Period of Maximum Drawdown				
Fort Union Formation	2006–2009	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Deep Wasatch Sands	Drawdown in the deep Wasatch Sands would occur several years after drawdown in the coal occurs.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Buildup				
Shallow Wasatch Sands	Up to 50 feet near impoundments. Up to 10 feet farther from impoundments.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Alluvium	Up to 10 feet has been documented; anticipated rise in water level could be more or less.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Infiltration and Recharge	Recharge of shallow Wasatch aquifer increased during CBM development as a result of infiltration below creeks and impoundments that receive CBM discharge water. An estimated 15 to33 percent of CBM produced water infiltrates the surface.	Similar to Alternative 1. An estimated 28 to 43 percent of CBM produced water infiltrates the surface	Similar to Alternative 1. An estimated 21 to 30 percent of CBM produced water infiltrates the surface.	Similar to Alternative 1, however, the volume of water produced under Alternative 3 would be a little more than half the volume of water produced under Alternative 1. Although the same percentage of CBM-produced water would infiltrate the surface, the volume of water infiltrating the surface likely would be reduced by half.
Quality	Groundwater quality within the regional aquifer systems and alluvial aquifers would not be noticeably affected.	Same as Alternative 1	Same as Alternative 1.	Same as Alternative 1
Recovery	Rapid initial recovery of water levels in developed coals following cessation of CBM pumping. Recovery to within 50 to 100 feet of predevelopment water levels occurs by 2030. By 2060, water levels in the coal would recover to within 10 to 50 feet of pre-operational levels, exception in very localized areas of the basin. Water levels eventually would recover to within 20 feet or less of pre-operational levels over the next hundred years or so. Recovery of more than 50 percent in the deep Wasatch Sands would occur by 2030. Water levels eventually would recover to within less than 20 feet of pre-operational levels over the next hundred years or so.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1

Table 2–42 Summary of Effects, by Alternative

Potential Effect	Alternative 1	Alternative 2A	Alternative 2B	Alternative 3
Springs/Wells	Wells completed in developed coals that are located within the areal extent of the 100-foot drawdown contour could experience drops in water level and possibly methane occurrence. Flowing artesian wells and springs that emanate from coals in this area are likely to experience a decrease in flow rate. Recovery of artesian conditions likely would not occur unless recovery of the last five percent or so of hydraulic head occurs. Wells and springs in the Wasatch aquifer are not expected to be substantially affected unless they are within 100 feet (vertically) of developed coal.	Same as Alternative 1	Same as Alternative 1	Same as Alternative 1
Surface Water				
Quantity	An estimated 33 to 62 percent of CBM produced water would contribute to surface flows. Perennial flows likely to develop in formerly ephemeral channels	Similar to Alternative 1; an estimated 9 to 52 percent of CBM produced water would contribute to surface flows.	Similar to Alternative 1; an estimated 6 to 52 percent of CBM produced water would contribute to surface flows.	Similar to Alternative 1; however, the volume of water produced under this alternative would be a little more than half the volume produced under Alternative 1. Although the same percentage of CBM produced water would contribute to surface flows, the volume of water would be reduced by half.
CBM produced water discharged to main stems during peak year of water production	200,336acre-feet	131,937 acre-feet	125,109 acre-feet	102,917 acre-feet
Quality	Noticeable changes in water quality of main stems during periods of low flow. NPDES permit conditions would provide enforceable assurance that water quality standards and designated uses would not be degraded from discharges of CBM produced water.	Similar to Alternative 1; however, changes would be less noticeable because of the decrease in direct surface discharge.	Similar to Alternative 1; however, changes would be less noticeable because of the decrease in direct surface discharge and increase in the proportion of CBM produced water to undergo active treatment.	Similar to Alternative 1