CHAPTER 2
PROPOSED ACTION AND ALTERNATIVES

This chapter describes the Proposed Action and alternatives for the development of the Ferron Natural Gas Project. The alternatives described in this chapter include alternatives analyzed in detail and alternatives that were considered but dismissed from detailed analysis. The environmental effects of each alternative considered in detail, including the No Action alternative, are summarized and compared at the end of this chapter.

2.1 ALTERNATIVE 1 — PROPOSED ACTION

The Proposed Action consists of the development of 353 natural gas wells, various ancillary facilities, and a transmission pipeline. Sixty-five new wells would be developed in the 18,350-acre North Area and 220 new wells would be developed in the 93,170-acre South Area (**Plate 2–1**).

During the past several years, drilling activity and road construction/upgrading has occurred in both the North and South areas. Anadarko has completed 15 wells within the North Area: seven on federal leases and eight on state leases. Additionally, Anadarko has completed six wells on state leases and two wells on private land with federal minerals south of the North Area (**Plate 2–1)**. Texaco and Chandler have completed 53 wells in the South Area; 23 on federal leases, 10 on state leases, and 20 on private leases (**Plate 2–1**). Therefore, the total number of wells at full development of the Ferron Natural Gas Project would be 353 wells, including the 68 already drilled and 285 proposed.

The ancillary facilities include access roads, pipelines for gathering gas and produced water, electrical utilities, central production facilities (CPFs) for treating and compressing gas and disposing of produced water, and pipelines for delivering gas under high pressure to a transmission pipeline. The numbers of proposed wells, roads and facilities are shown in **Table 2–1**. The transmission pipeline, which would be 20 inches in diameter and almost 27 miles in length, would transport gas from the field to production facilities and ultimately to consumers.

The description of the Proposed Action in the following sections includes a description of the proposed well field development (both the overall project and features specific to each company) and a description of the proposed transmission pipeline.

2.1.1 Well Field Development

2.1.1.1 Overall Field Development Proposal

This section describes the general field development process. A detailed description follows this section.

The proposed locations of wells, access roads, pipelines, electrical utilities, and CPFs are shown on **Plate 2–1**. The primary targeted reservoir for the Project is coal bed methane gas from the Ferron Sandstone Member of the Mancos Formation. However, primary natural gas also may be extracted from the Ferron Sandstone at different depths than the coal seams. The wells are proposed to be developed on a 160-acre well density

Table 2–1
Alternative 1 Ferron Natural Gas Project Facilities

Facility	Company: Anadarko	Chandler	Texaco	Total[1]
Number of Existing and New Wells				
Existing on				
Federal lands	7	5	18	30
State lands	8	4	6	18
Private lands	0	1	19	20
Total	15	10	43	68
Proposed on				
Federal lands	46	44	40	130
State lands	9	27	64	100
Private lands	10	12	33	55
Total	65	83	137	285
Total number of natural gas wells	80	93	180	353
Lengths of Roads (miles)				
Potentially upgraded[2] on				
Federal lands	24.4	11.4	11.4	47.2
State lands	5.0	14.6	14.6	34.1
Private lands	1.8	10.4	10.4	22.7
Total[1]	31.2	36.4	36.4	104.0
Proposed new on				
Federal lands	9.6	22.0	16.8	48.4
State lands	2.5	10.7	22.7	35.9
Private lands	2.7	3.1	7.9	13.6
Total	14.8	35.8	47.4	98.0
Total lengths of upgraded or new roads[1]	46.0	72.2	83.8	202.0
Number of Disposal Wells	3	3	5	11
Compressors				
Existing Central Production Facilities[3]	1	1	2	4
Proposed Central Production Facilities[4]	1	1	3	7
Proposed Compressor Stations[4]	3	0	0	3
Total Horsepower	20,400	5,250	12,000	37,650

Note:
1. Totals may not match precisely with values obtained by adding unit numbers due to rounding conventions.
2. Both Texaco and Chandler would use the upgraded roads in the South Area. Therefore, the total lengths of upgraded roads in the South Area were split evenly between Chandler and Texaco.
3. Chandler and Texaco would decommission their existing CPFs once the proposed CPFs are on line. However, they would continue to use the disposal wells associated with the existing CPFs.
4. One amine unit and one dehydration unit would be installed at each facility or station.

Source: Companies' proposals.

pattern (four wells per square mile with one well in each quadrant of the section). The facilities shown on **Plate 2–1** serve as the basis of the environmental analysis in this EIS, evaluating the effects of implementation of the proposed field development, i.e., the total number of wells, roads, and other facilities. The site-specific analysis of the exact locations of all facilities would be determined subsequent to the EIS, based on a further refinement of environmental and engineering constraints at each site during the APD stage (as discussed in **Chapter 1**).

Construction of the Ferron Natural Gas Project would begin during 1999. Generally, construction would be completed within five years (by the end of 2004). The production lifetime of the wells is expected to be about 20 years and final reclamation is expected to be completed during the two to three years following the end of production. Thus, the Ferron Natural Gas Project is expected to be completed around 2027.

Most of the proposed wells in the Project Area would be coal bed methane (CBM) wells. Although construction, operation, maintenance, and abandonment of CBM natural gas wells are similar to that of conventional natural gas wells, two notable differences exist. First, the pressure in the coal seam must be reduced by the removal of water before CBM can flow to the surface. The water production rates are the highest and the CBM gas rates are the lowest when a well is first brought on line. Over time, water production decreases steadily after reaching a peak during the first one to two years. The gas production increases steadily for a few years, then gradually declines. Secondly, requirements for operational maintenance is higher with CBM wells. Coal fines from the target seams tend to migrate into CBM wells and plug up the wells and water pumps. Consequently, workovers are typically needed within the first few months after initial completion to remove these coal fines. Workovers for these types of problems are not required for conventional natural gas wells.

Development of the Ferron Natural Gas Project would include the following general categories of activities:

- construction of facilities,
- drilling and completion of wells(including the plugging of unsuccessful wells),
- production and maintenance of extracting CBM gas resources,
- construction and operation of the transmission pipeline,
- safety and emergency procedures incorporated into the project, and
- decommissioning and reclamation of the project's facilities.

The first step in the development of a well would be the construction of a rough access road to the location of the well pad. Vegetation would be cleared, topsoil would be stockpiled, and the well pad would be leveled. A mud pit then would be constructed adjacent to the proposed well bore. A portable drilling rig would be installed and drilling would begin. A typical well would be drilled to a depth of approximately 1,500 to 4,500 feet, which would take one to six days to drill. Upon successful completion, the well would be shut in or gas-flared/vented awaiting development of the infrastructure needed to transport the gas to a commercial transmission pipeline. The drilling rig would be removed and the mud pit would then be reclaimed. If the well is determined to be capable of economic production, the well would be stimulated and produced water and gas gathering pipelines generally would be constructed along the access road. If economically feasible, electric utility lines also may be installed to the well site.

Concurrently with the drilling of production wells, deep wells for the disposal of produced water would be drilled. These disposal wells would be drilled in a similar manner as production wells, except they would be drilled to depths of about 6,000 feet using drilling mud, a larger drilling rig would be needed, and drilling would take about one month. An additional week would be needed to complete the disposal well.

After a group of wells has been completed, the wells would be interconnected by gas and produced water pipelines to transport gas and water to the CPF. The CPF would consist of a water disposal well, a compressor station, an amine unit (to remove carbon dioxide), and a dehydration unit (to remove water from the gas stream). The purpose of the CPF would be to dispose of the produced water and attain the ultimate pressure required to transport the gas to the proposed transmission pipeline. Concurrently, a high-pressure gas delivery pipeline would be constructed to transport gas from the CPF to existing or proposed transmission pipeline.

When ancillary facilities for a cluster of wells are functional, the field would be ready for production. At each well, a pumping unit, a water separation system, a gas meter, and connections to the gas and water collection systems would be constructed. Gas and produced water would then be transported to the CPF via the pipeline network and processed. Then, the gas would be transported to the sales pipeline. The pumping unit would be maintained at each well until the coal seams are dewatered. At this point, the gas would flow under natural pressure and the pumping unit may be removed. There is not enough production history to conclude that the wells would not produce some water throughout the project's life. Some type of pump may always be required to lift water, but produced water would decrease significantly from the initial production rates. As further clusters of wells would be completed, further pipelines, central production facility, and delivery pipelines would be constructed. This development sequence would continue within the Project Area until the proposed field development is attained.

2.1.1.1.1 Construction Phase

This section describes the overall procedures, techniques, and resources that would be employed to construct the facilities comprising the Proposed Action. These facilities include roads, pads for gas wells and disposal wells (for produced water), pipelines, electric utilities, and compressors. Resources needed for construction include labor, materials, and equipment. Dust suppression techniques on all construction areas would be applied in accordance with State of Utah regulations.

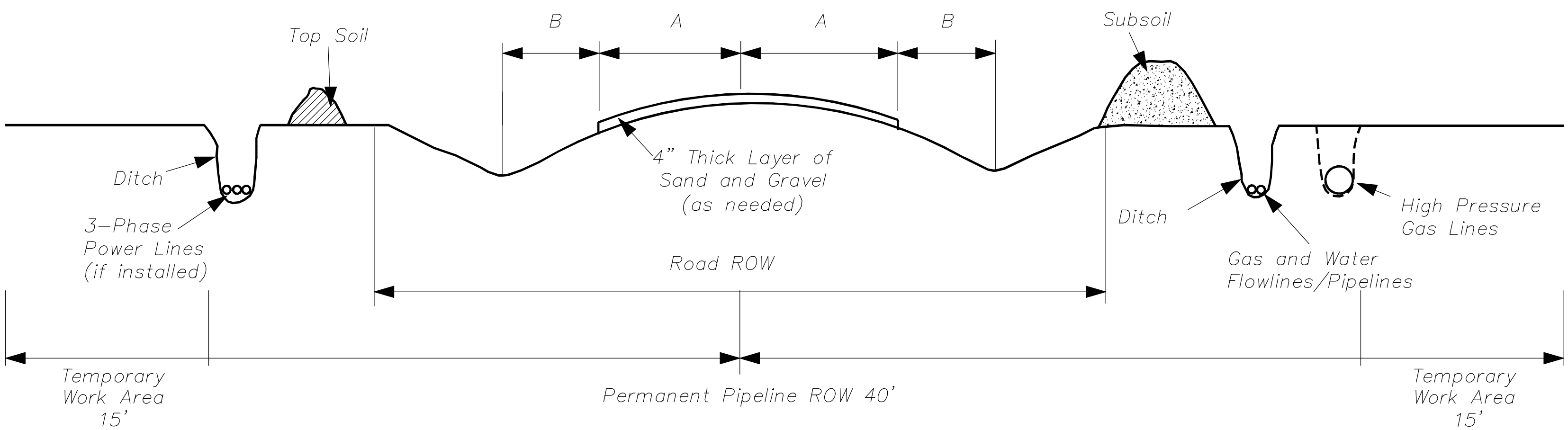
2.1.1.1.1.1 Roads

A network of roads already exists within the Project Area. These roads would be used as is or upgraded where acceptable for access to project facilities. New roads would be constructed only where necessary. Because the proposed locations of well pads and compressors relative to existing roads vary, lengths of these roads constructed to access these facilities also vary. The overall network of existing, proposed, and potentially-upgraded roads is shown on **Plate 2–1**.

Under the Proposed Action, three classes of roads would be constructed. They are collector roads, local roads, and resource roads. **Plate 2–1** shows the distribution of the 98 miles of proposed roads in the North and South areas, as classified by the BLM's road classification system. On federal lands, all roads would be constructed to BLM or Forest Service standards (**Figure 2–1**). For discussion purposes, all roads proposed are assumed to be BLM roads.

Collector roads are existing or planned roads necessary for support of existing facilities. These roads normally provide access to larger blocks of land and connect with, or are an extension of, an existing public road system. Collector roads receive a high volume of traffic and usually require application of the highest construction and maintenance standards used by the BLM. The design speed is 25 miles per hour (mph). The minimum width for the travel way ranges from 20 feet to 30 feet. Although the actual width would vary with site-specific conditions, the average width for the travel way is expected to be 24 feet.

Local roads are existing or proposed roads that would serve the development of depletable natural resources or temporary facilities. These roads receive lower volumes of traffic than collector roads and usually provide



	Surfaced Travel Way Width (ft.)	A (ft.)	B (ft.)	Approximate Disturbance Width (ft.)	Total ROW Width (ft.)
Resource Road	16	8	4	70	40
Local Road	20	10	4	70	40
Collector Road	24	12	4	70	40

Not To Scale

Figure 2-1
Typical Roadbed
and Pipeline/Utility Trench Cross Section

the internal access network within an oil/gas field. The design speed is 20 mph and width of the travel way usually is 20 feet (a minimum of 20 feet to a maximum of 24 feet).

Resource roads are existing and proposed roads that serve the development of a limited area of a depletable natural resource. These minimal roads usually provide the final segment of access to a well site. The design speed is 15 mph and width of the travel way usually is 16 feet (a minimum of 16 feet to a maximum of 24 feet).

Most roads to well pads (resource roads) would be constructed in two steps. Initially, each road would be roughed in and probably unsurfaced during the construction phase. The need for surfacing would be determined in consultation with the BLM or other landowner based on site-specific conditions. If the well is completed successfully, the road would then be completed to appropriate final specifications. However, if the well is not completed successfully and is plugged, the road would be reclaimed. Roads to other facilities would be constructed to final specifications in a single step.

Access roads constructed on public lands would follow existing two-track roads or trails, where practical. Construction of roads on state or privately-owned lands would follow agreements between the companies and individual landowners. Access roads across public lands would be designed and constructed according to BLM's Manual 9113 standards. The design and staking of all permanent roads on public lands also would be conducted under the direction of a licensed, professional engineer. Construction would be monitored by a qualified professional engineer or qualified inspector, as deemed appropriate by the BLM and Forest Service.

Access roads would be constructed using standard equipment and techniques, such as the crown-and-ditch method (BLM and Forest Service 1989). Heavy equipment would clear vegetation and topsoil materials from the road surface. Both materials would be windrowed for future redistribution during reclamation. All roads would be constructed with appropriate, adequate drainage and erosion control features/structures (e.g., cut and fill slope and drainage ditch stabilization, relief and drainage culverts, water bars, wing ditches, and rip-rap). Where needed, four inches of sand and gravel would be placed on newly-constructed roads to provide a year-round travel way surface.

2.1.1.1.1.2 Wells

The Proposed Action includes the construction of 65 gas wells on federal, state, and private lands in the North Area. Forty-six wells would be constructed on federal lands administered by the BLM. About nine wells would be constructed annually on these federal lands from 1999 through 2003. The other 19 wells would be constructed on state and private lands.

Of the 220 wells proposed for the South Area, 84 wells would be drilled on federal lands administered by the BLM. About 17 wells would be constructed annually on these federal lands from 1999 through 2003. The other 136 wells would be constructed on state and private lands.

2.1.1.1.1.2.1 Well Pad Construction

Construction of a well pad primarily would involve preparing a level area for the equipment that would drill and complete the well. The minimum area required for a well pad varies by company. Overall, the sizes of well pads would range from a minimum of 1.0 acre (200 feet by 225 feet) to a maximum of about 1.4 acres (200 feet by 300 feet). **Figure 2–2** shows the typical layout of a well pad.

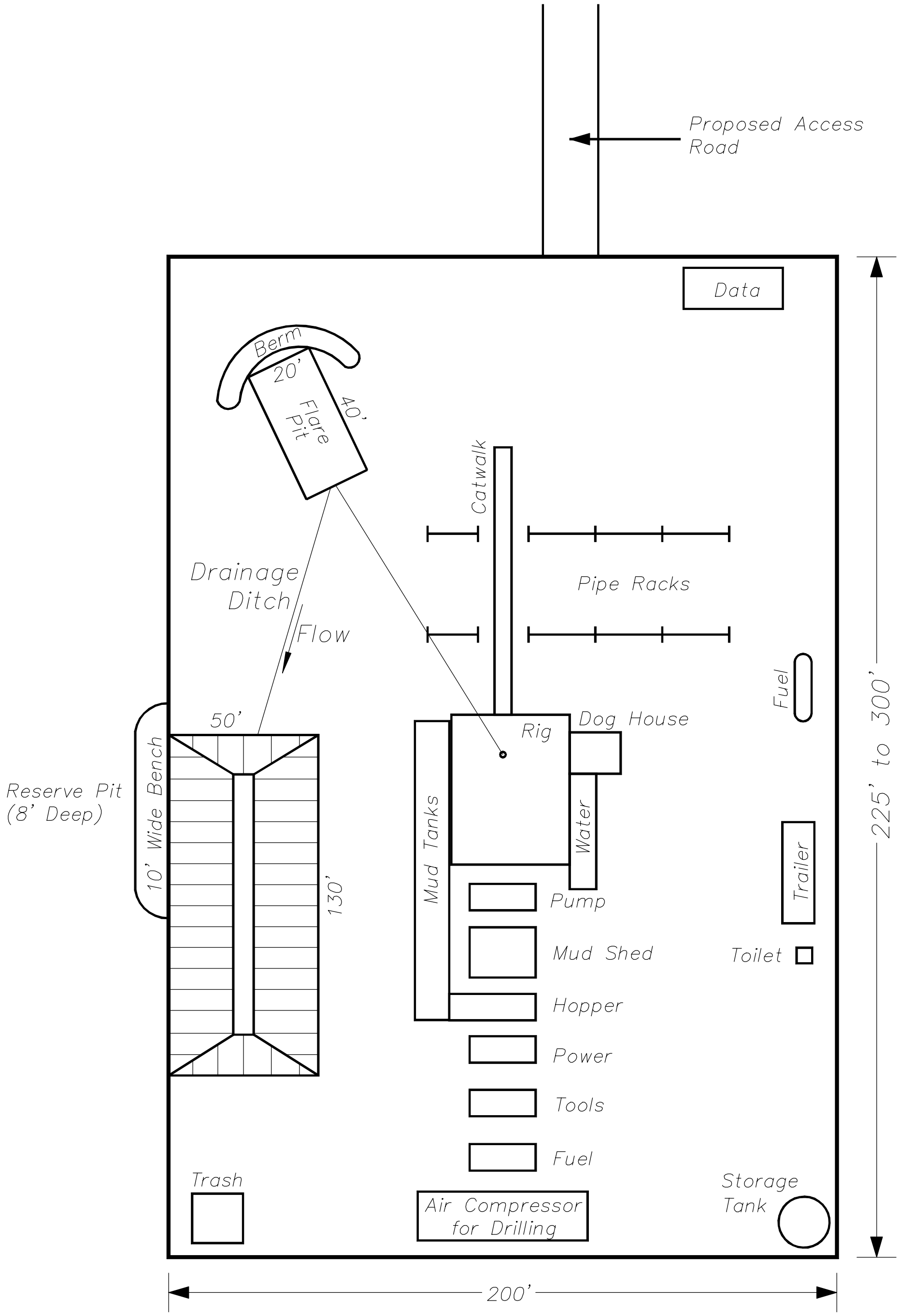


Figure 2-2
Typical Well Pad Schematic

Not To Scale

Construction of each well pad would follow a distinct series of steps (BLM and Forest Service 1989). First, vegetation on the pad would be stripped. In general, topsoil also would be stripped from the pad and stockpiled. However, in areas where minimal grading is required or where soils are naturally saline, alkaline, or both, topsoil would be stripped only from the drill cutting pit.

After vegetation and topsoil are stripped, the pad would be graded using standard cut-and-fill techniques of construction using a bulldozer, grader, or both. If the BLM or Forest Service determines site-specific conditions warrant, the pad may be surfaced with sand or gravel to minimize disturbance of soils and to promote efficient drainage. On part of the pad, a pit (with maximum dimensions of 50 feet wide by 130 feet long by 8 feet deep) would be excavated. This pit, which would receive cuttings during drilling, may be lined with an approved plastic liner, for example, High Density Polyethylene (HDPE) with a thickness of at least 12 millimeters. A determination of whether a pit liner is needed would be a site-specific decision made by the Authorizing Officer.

2.1.1.1.1.3 Pipelines

Three types of pipelines would be constructed as part of the Proposed Action. They are gas-gathering pipelines, produced water-gathering pipelines, and high-pressure gas delivery pipelines. The gas-gathering and produced-water gathering pipelines would conduct gas and produced water from the wells to compressor facilities and produced-water disposal facilities, respectively. The high-pressure gas pipelines would connect compressor facilities to the existing and proposed transmission pipelines. Most pipelines would be buried underground. However, some may be laid on the ground where rocky conditions would result in more environmentally damaging and expensive construction methods. Site-specific determinations would be made by the Authorizing Officer.

In general, all three types of pipelines would be installed in rights-of-way along access roads. Gas-gathering pipelines and produced water-gathering pipelines would be placed together in the same trench/ditch paralleling the access roads (**Figure 2–1**). High-pressure pipelines would be installed in a separate ditch (**Figure 2–1**). Gas and produced water-gathering pipelines would be constructed of polyethylene or steel pipe with an outside diameter of 2 to 10 inches. They also would be constructed with manholes to provide access for maintenance and operational purposes. The locations of the manholes would vary depending on the specific pipeline characteristics. Each manhole would be protected by an aboveground barricade that is painted yellow for safety. The high-pressure pipelines would be constructed of steel pipe with an outside diameter of 4 to 10 inches.

Generally, pipeline construction would occur in a planned sequence of operations along or within roads. The path would first be cleared of trees and heavy brush by blading the surface. 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). Soils would be left undisturbed over much of the construction work area, although some compaction may occur.

Construction would be completed using the following steps: pipe stringing, trench excavation, pipe lowering, pipe padding, and trench backfilling. Materials, equipment, and techniques, including quality assurance control checks, would follow the standards for the industry. The pipeline trench would be excavated mechanically with a track excavator to a depth that allows 3.5 feet of material to be placed on top of the pipeline. Trench width would likely range from approximately 18 to 36 inches, depending on the number of pipelines and the diameter of pipe placed in the trench bottom. Earthen materials would be backfilled promptly into the trench following installation.

Before being placed into service, each gathering pipeline would be tested with pressurized fresh water (hydrostatic testing) or air to locate any leaks. After completion of hydrostatic testing, waste water would be directed to the water collection and disposal system (disposal wells) for final disposal. Site regrading would occur where necessary. Reclamation of the portion of the construction ROW not to be retained as part of the adjacent road would be initiated per landowner requirements (i.e., BLM, Forest Service, state, or private) so as to return this temporary disturbance area to productive use and to stabilize soils.

2.1.1.1.1.4 Electric Utilities

Although the Companies would prefer to use gas-fired compressors and pumps, their proposals include the optional use of electric compressors, electric pumps, or both instead of gas-fired equipment. This section describes an electrical option for the Proposed Action, which is based on the Companies' preferences for an electrical system, if they were to construct the Proposed Action with electrical equipment.

Based on projected power demands, it is anticipated that the Companies would require 1 megawatt (MW) per day to transport five million cubic feet of natural gas per day (MMCFD). Based on this power demand, the maximum power requirement would be 33 MW per day. **Figure 2–3** shows the expected average daily power requirements for each year of operations for the Proposed Project.

Under this option, three-phase 12kV distribution lines would connect wells and compressor facilities with the existing transmission and distribution system within the Project Area. Electricity would be routed to wells and compressors aboveground on poles generally located along the access roads or on additional 10-foot-wide rights-of-way across open land. The installation and power would be provided by Utah Power and Light. Power line construction would follow access road surfacing and 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. Electrical junction boxes would be installed as necessary by the public utility. These boxes would be painted with an Agency-approved color to blend with the surrounding environment after each well begins operation.

The power lines would be constructed using tracked and wheeled equipment. A crew with a backhoe or a line-boom truck with an auger attachment would dig the holes where accessible from access roads. The holes would be located as to not disturb existing sensitive vegetation and would be excavated to a depth of 8 to 10 feet. Poles would be transported to the construction site by truck where the structural components would be assembled on the ground and erected by a boom truck.

Pole locations could be moved within the 10-foot wide ROW if topography and/or impacts to cultural, vegetative, or wildlife resources are identified at the site of the structure. In areas of thick vegetation and/or where vegetation may impede the performance of the active line, vegetation would be cleared by hand-held chainsaws or any other equipment needed to complete the job. Where areas of sensitive plant resources are known to occur, the BLM would be consulted before removal of any vegetation.

When the structures are in place, the conductor would be strung. A sock line would be laid along the route by a light vehicle or by hand. Ground crews would place the sock line in pulleys on each structure at the insulator location. The conductor would then be pulled up by pulleys through the insulator with the assistance of a reel truck, or by hand, before moving to the next pole location. At least two miles of conductor could be pulled into place in a single setup.

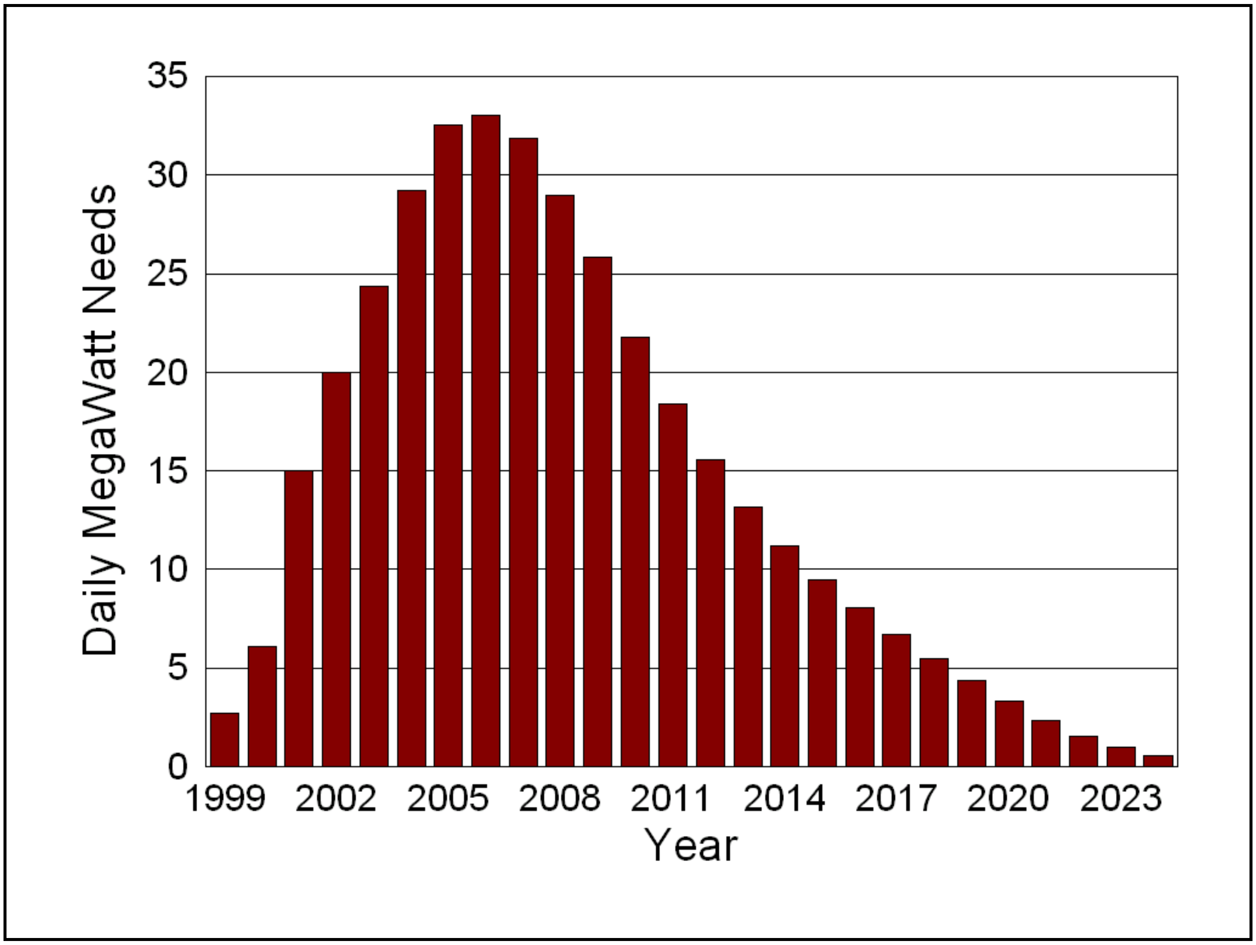


Figure 2–3 Electricity Forecast for the Ferron Natural Gas Project

Under this option of the Proposed Action, all electric lines would be installed aboveground on 30-foot tall poles, which would look similar to telephone poles. Poles would be required approximately every 300 feet. Approximately 187 miles of above groundpower lines and 3,302 power line poles would be installed in the Project Area. The distribution of the lines is shown on **Plate 2–2**. **Table 2–2** shows the linear extent of the power lines and the number of poles required for each classification of land ownership.

2.1.1.1.1.5 Produced Water Disposal

2.1.1.1.1.5.1 Water Disposal Wells

Essentially, the actual construction of pads for produced-water disposal wells would follow the same basic procedures described for the pads for gas wells. The pad would be stripped of vegetation and topsoil. Then, it would be graded using standard cut-and-fill techniques of construction and a bulldozer, grader, or both. If the surface-managing agency or owner determines site-specific conditions warrant, the pad may be surfaced with sand or gravel to minimize disturbance of soils and to promote efficient drainage.

Table 2–2
Summary of Above Ground Power Lines for the Proposed Action

	Land Ownership			
Facility/Area	**BLM**	**State**	**Private**	**Total**
Miles of Power Line				
North Area	30	10	3	43
South Area	59	56	29	144
Total	89	66	32	187
Number of Poles				
North Area	525	182	55	762
South Area	1,040	990	510	2,540
Total	1,565	1,172	565	3,302

Although the basic construction procedures would be similar, two primary differences would exist between the pads for gas wells and pads for produced-water disposal wells. First, most of the pads for produced-water disposal wells would be located with compressor units on a central production facility (CPF). The typical layout of the disposal well facilities at a CPF is shown in **Figure 2–4.** An access road, a produced water pipeline, and maybe an electrical distribution line would be constructed to the disposal well. Disturbance from the disposal well would total approximately one-half (3.1 acres) of the 6.2-acre CPF. Installed features of the disposal well would include the well, electric- or gas-powered disposal pump, and several 500- to 1,000-barrel tanks for storing water. Lights (250 watts each) would be installed on poles and directed downward to illuminate key areas.

Second, emergency pits would be constructed and connected to each disposal well. If a disposal well has to be shut down for repairs, the companies would use these pits for the short-term storage of produced water that would normally be sent to the disposal well. If the company cannot repair the disposal well before the emergency pit reaches capacity, pumps at the gas wells that are sending produced water to the emergency pit would be shut down until the disposal well is repaired. Once the disposal well is repaired, any water in the emergency pit would be pumped to the well for disposal.

The sizes and number of the emergency pits would vary by company; however, all emergency pits would be lined with synthetic liners to prevent infiltration of produced water. Most pits would range in size from 30 feet by 50 feet by 10 feet (capacity = 2,500 barrels of water) to 115 feet by 115 feet by 8 feet (capacity = 18,850 barrels of water). Disposal wells in the South Area would have an emergency pit associated with each of them on the CPF. However, in the North Area, one large emergency pit that was originally designed as an evaporation pond would service all disposal wells. Specific differences among the Companies' proposals for emergency pits are discussed later in this chapter.

2.1.1.1.1.6 Gas Compression

Currently, four gas-powered compressors are operating within the Project Area. Texaco operates two gas-powered compressor facilities, one in Township 18 South Range 7 East in the NW¼ of Section 24 and one in the NW¼SE¼ of Section 35. Anadarko operates a compressor located in Township 14 South Range 10

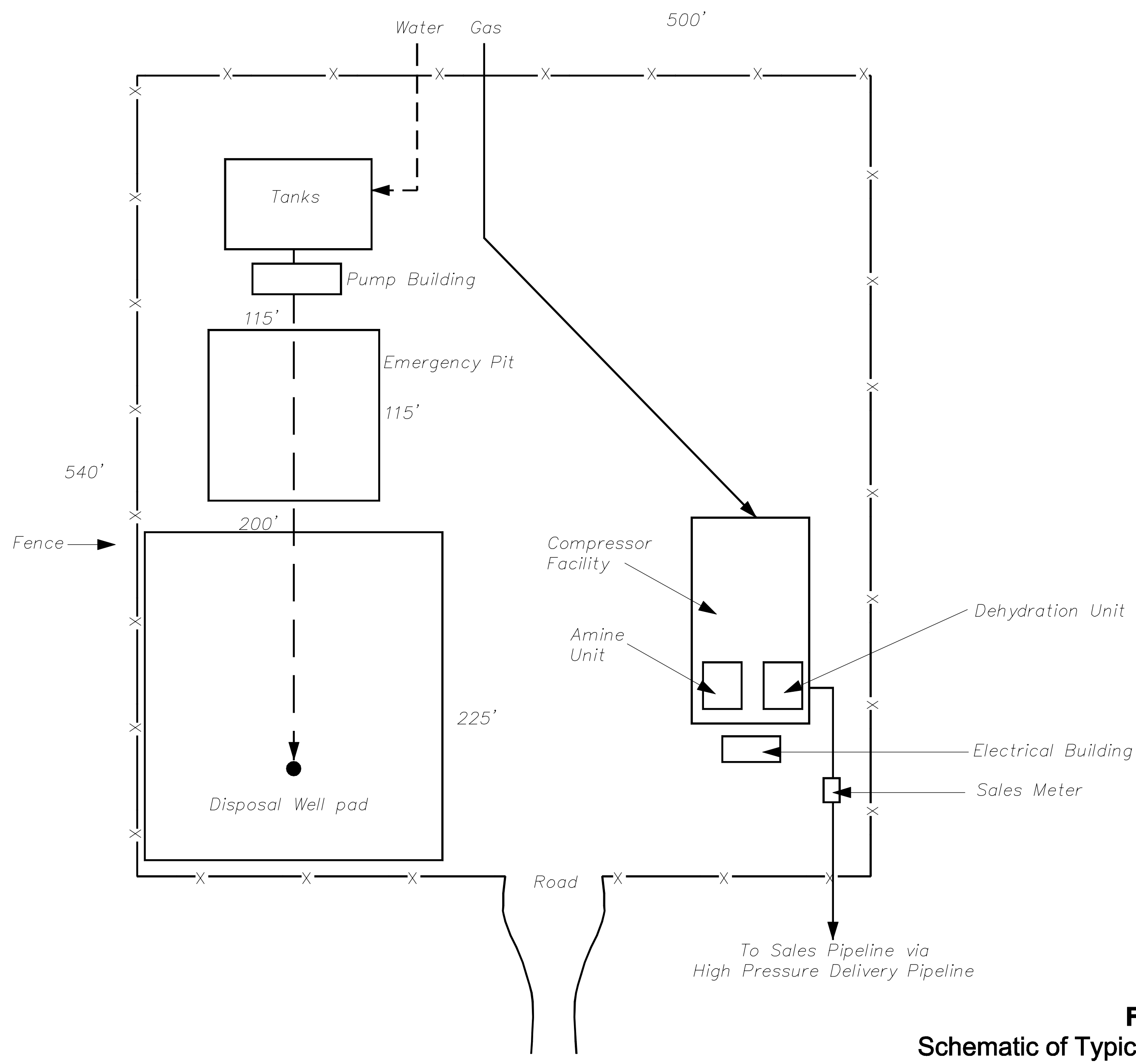


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Figure 2-4
Schematic of Typical Central Production Facility

East, Section 3. Chandler operates a compressor in Township 19 South, Range 7 East in the NE¼ of Section 11. Upon reaching the full development of the Ferron Natural Gas Project, these existing compressors would be decommissioned.

The compressor sites would be constructed similarly to the well pads. An access road would be constructed from the transportation network to the site. Vegetation would be cleared and topsoil would be stripped and stockpiled. An area of about 6.2 acres (500 feet wide by 540 feet long) would be graded using standard cut-and-fill construction techniques and machinery (bulldozer and/or grader). The components for the compressor facility then would be installed. Concurrent with construction of the compressor s, gas pipelines would be built to the site.

The Proposed Action includes a maximum of 10 new compressor stations at the approximate locations shown on **Plate 2–1**. Additionally, one new compressor station would be constructed south of the North Area and Anadarko's existing compressor would be upgraded. The typical layout for the proposed compressor facilities is shown in **Figure 2–4**. Long-term disturbance for the construction and operation of a compressor facility for the life of the project would total approximately 3.1 acres of the 6.2-acre CPF. 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.

2.1.1.1.1.7 Workforce Requirements

Most of the active workforce involved in developing the Proposed Action would be involved 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 the field. **Table 2-3** shows the estimated employment requirements for the construction, operation, and reclamation of the FNG Project under the Proposed Action.

2.1.1.1.1.8 Construction Resource Requirements

2.1.1.1.1.8.1 Materials and Equipment

Construction of the Ferron Natural Gas 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. Equipment needed for construction would include heavy equipment (bulldozers, graders, track hoes, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, well pads, 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 about 84 acre-feet (**Table 2–4**). This water would be purchased from local sources.

2.1.1.1.2 Drilling/Completion Phase

2.1.1.1.2.1 Roads

As many as 104 miles of existing roads may need to be upgraded to handle the increase in traffic projected under the Proposed Action (**Table 2–1**). About 45 percent of the roads potentially needing upgrading occur

Table 2–3
Estimated Employment Requirements for Ferron Natural Gas Project

Work Category	Time Requirements	Number of Facilities	Personnel Required (# per day)	Workdays for Project	Workdays per Year	Average Workers per Day
Construction and Installation						
Access Road	4 days/mile	98 miles	4	1,568	314	1
Well Pad	2 days/site	285	8	4,560	912	4
Pipeline	10 days/mile	98 miles	10	9,800	1,960	8
Electrical Utility Lines[1]	5 days/mile	187 miles	4	3,740	748	3
Drilling and Casing	4 days/well	285	8	9,120	1,824	8
Well Completion	4 days/well	285	20	22,800	4,560	19
Well Production	10 days/well	285	16	45,600	9,120	38
Compressor Facility/station	90 days/site	10	20	18,000	3,600	15
New Disposal Wells	40 days/well	8	8	2,560	512	2
Total				117,748	23,550	98
Operation and Maintenance						
Road/Pad Maintenance	120 days/year	NA	3	7,200	360	2
Pumpers	260 days/year	NA	36	187,200	9,360	39
Office	260 days/year	NA	2	10,400	520	2
Well Workover	5 days/well	10/yr	2	2,000	100	0
Total				206,800	10,340	43
Reclamation and Abandonment						
Wells (gas and water)	3 days/well pad	364	4	4,368	NA	
Roads	4 days/mile	98	4	1,568	NA	
Compressor Dismantling	30 days/facility	14	20	8,400	NA	
Reclamation	5 days/facility	14	4	280	NA	
Total				14,616		

Note:
1. Applies to the electrical equipment option only.

on BLM-administered lands. Another 33 percent of the roads occur on state lands and 22 percent occur on privately-owned lands. **Plate 2–3** shows the distribution of the roads potentially needing upgrading.

The rough access road constructed for initial access to the well pad also would be used for the drilling phase. If the well is not successfully completed, the road would be reclaimed using the methods described in the Reclamation Plan (**Appendix A**). If the well is completed successfully, the rough road would be upgraded to the appropriate class (most access roads to well pads would be resource roads).

Table 2–4
Summary of Water Requirements for the Proposed Action

Item	Amount (size)	Rate	Total (acre-feet)
Roads and pipelines	98 miles	0.36 acre-feet/mile	35
Well pads	393 acres[1]	0.023 acre-feet/acre	9
Central production facilities	43.4 acres	0.29 acre-feet/acre	13
Compressor stations	9.3 acres	0.29 acre-feet/acre	3
Drilling and completion			
Proposed Gas wells	285 wells	0.05 acre-feet/well	14
Proposed Disposal wells	8 wells	1.26 acre-feet/well	10
Total			84

Note:
1. Areal extent based on 285 gas wells.
Source: Cox 1998.

Sand and gravel also would be required in the construction of roads, well pads, and compressor facilities. Sand and gravel would be used to surface all newly-constructed roads in the collector and local classes to ensure a surface sufficient for year-round travel. The need for adding gravel to resource roads would be determined by the Authorized Officer or landowner on a case-by-case basis.

Table 2–5 summarizes the estimated amount of sand and gravel needed if surfacing is required on all new roads, roads potentially requiring upgrading, well pads, and compressor facilities. Approximately four inches of sand and gravel would be applied where needed on roads and well pads. The Companies would purchase sand and gravel from local commercial sources.

Table 2–5
Summary of Sand and Gravel Requirements for the Proposed Action

Facility	Amount	Unit	Application Rate (cubic yards per unit)	Total Volume (cubic yards)
New roads	98	miles	1,430	140,140
Potentially-upgraded roads	104	miles	1,430	148,720
New well pads	285	pads	832	237,120
New central production facilities	7	facilities	3,225	22,575
Compressor, amine, and dehydration stations	3	stations	1,613	4,838
Total				553,393

Source: Cox 1998

2.1.1.1.2.2 Wells

2.1.1.1.2.2.1 Drilling

Following construction of the access road and well pad, a mobile drilling rig would be transported to and erected on the well pad. Trucks would be used to transport drilling components to the pad. Components of these rigs are designed for portability. Thus, they are easily loaded and unloaded and mostly self-contained on the mobile drill rig. Auxiliary equipment for supplying electricity, compressed air, and/or water also would be trucked in for drilling operations. Drill pipe, drill bits, cement, water, wire rope, and other necessary supplies would be trucked to the well pad and stored temporarily until used. An approximate layout of the well pad during drilling activities is presented in **Figure 2–2**.

The active phase of drilling would begin by setting the four tie-down anchors to guy the derrick tower and digging a pit, called a cellar, where the hole would be drilled. The cellar would provide space for the casing head spools and blow-out preventers that would be installed under the rig. Drilling operations normally include (1) keeping a sharp bit on bottom drilling as efficiently as possible, (2) adding a new joint of pipe as the hole deepens, (3) pulling the drill string out of the hole to put on a new bit and running it back to the bottom, and (4) installing casing and cementing it in the hole. Typically, an 11-inch (diameter) hole would be drilled to a depth of 300 feet; a 7f-inch hole would then be drilled to a depth 250 feet below the lowest target formation.

The conclusion of well drilling operations would involve placing and cementing the well production casing. Placement of production casing (casing the hole) would entail the insertion of a steel pipe into the drill hole from the bottom of the hole to the surface. Casing would be set in 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. Each well would be completed with 8e-inch to 9e-inch surface casing to a depth of 300 feet and 4½-inch to 7-inch production casing to total well depth. Final well depths are anticipated to range from approximately 1,500 to 4,500 feet.

The casing would be partially 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) to 250 feet above the target interval. A plug and rinse are 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.

A cement bond log would be run on the well to ensure no voids remain in the annulus. Cementing the annulus around the casing pipe restores the original isolation of formations by posing a barrier to the vertical migration of fluids between rock formations within the borehole. It also protects the well by preventing formation pressures from damaging the casing and retards corrosion by minimizing contact between the casing and corrosive formation fluids.

All drilling operations and other well site activities would be conducted in compliance with applicable BLM and UDOGM rules and regulations. As many as six rigs are expected to be used during the drilling period on federal lands and when conditions permit on state and private lands. Each gas well is expected to be drilled within a one- to six-day period, with an average of four days expected.

All wells would be completed in the Ferron Sandstone Member of the Mancos Formation using vertical air drilling techniques, unless special conditions arise requiring drilling mud (such as the presence of substantial water). To date, minimal drilling with mud has been required. With air drilling, compressed air and a slight amount of surfactant would be used to remove drill cuttings from the hole and control pressure. Excess surfactant and cuttings would be blown into the drilling pit for disposal.

During drilling operations, certain waste waters would be generated, including frac fluids and, potentially, drilling fluids, in addition to the produced water. Where limited quantities of frac fluids (a mixture of water, guar gel, sand, and pH- and bacteria-control chemicals), drilling fluids, or other waste water liquids are generated during drilling, they would be discharged into the reserve pit constructed at the site in accordance with current applicable rules and regulations. After drilling, the water in the pit would be allowed to evaporate. After the pit is completely dry, it would be backfilled.

2.1.1.1.2.2.2 Completion

To prepare each well for the production of gas, a well completion program would be initiated to stimulate production of gas and determine gas and water production characteristics. A mobile completion rig similar to the drill rig would be used to complete a well. The well completion process, which usually lasts from 7 to 14 days, includes perforating the well's steel casing, fracturing the producing formation hydraulically, and installing a series of valves and fittings on the wellhead (called a "Christmas tree").

Perforation of the well casing involves the creation of holes in the casing wall to provide a flow path into the well from the target production interval. Holes are produced by the detonation of a shaped charge placed within the well casing at the desired depth interval. Energy produced by detonating the shaped charge is directed through the well casing wall and hardened cement. The holes through the cement and well casing allow pumped fluids to enter the formations and stimulate the inflow of gas and produced water. Each well would be stimulated using a standard process known as hydraulic fracturing, which stimulates production by increasing the permeability of the producing formation.

In hydraulic fracturing, frac fluid (water and nontoxic additives) is pumped under pressure downward through the casing or tubing and out through the perforations in the casing. The pressurized fluid enters the formation and parts or fractures it. Sandgrains or other proppants (aluminum pellets, glass beads, or similar materials) are carried in suspension by the fluid into the fractures to "prop open" the fractures in the coal. When the pressure is released at the surface, the fracturing fluid returns into the well and the fractures partially close on the proppants, leaving channels for gas and water to flow through into the well. The frac fluid pumped into the casing is recovered and recycled or disposed of with the produced water. Installing the Christmas tree and associated tubing is the final step of the well completion work.

Even though the produced water and gas can flow into the casing after it is perforated, a small diameter pipe, called tubing, is placed in the well to serve as a way for the produced water to be brought to the surface. Typically, tubing is placed below the perforated interval so fluids that collect in the bottom of the well can be pumped up the tubing to the surface. At the surface, the collection of valves (Christmas tree) sits at the top of the well head. The tubing in the well is suspended from the Christmas tree, so as the well production flows up, it enters the Christmas tree. As a result, the production from the well can be controlled by opening and closing valves on the Christmas tree.

All completion activities would be limited to daylight hours, when possible. Minimal venting of gas at well sites would occur during completion or connection of the well to blowlines. Minimal venting also could occur when the well is flowed to surface following hydraulic fracturing. The flowing back of a well is necessary to purge the fluids used in the fracturing process. During the process of flowing back the well, slight amounts of gas are produced. The gas and water are flowed to the drilling pit, to temporary storage tanks on location, or to the gas and water gathering pipeline systems, if operational. If the volume of water produced during the flowing back of the well is too great for the drilling pit or temporary storage tanks to hold entirely, water in the pit, tanks, or both would be pumped into trucks and transported to the disposal well for disposal.

Any gas entering the tanks with the water is separated and vented to the free atmosphere. In general, venting would only occur during the recovery of the water and is expected to last only a few days. However, Anadarko proposes to vent gas for a maximum of 30 days until the necessary infrastructure is constructed to transport gas and water to CPFs. A complete description of Anadarko's proposed method is found in **Section 2.1.1.2**, Company Breakdown of Proposed Well field Development. Any venting would be in accordance with Utah Administration Code Rule R–649–3–20, BLM's Notice to Lessees 4A (Royalty or Compensation for Oil and Gas Lost) and Onshore Order No. 5 (Measurement of Gas). After the water used in the fracturing is recovered, the well would be tied into the gas and water collection system.

Flaring may be necessary following completion of wells located distant from the existing pipeline infrastructure to determine whether the wells are capable of production in sufficient quantities to justify pipeline installation. Flaring would be done in accordance with all applicable laws, rules, and regulations, including as appropriate, compliance with Utah Administration Code Rule R–649–3–20, BLM's Notice to Lessees–4A and Onshore Order No. 5. These rules address the time frames and maximum amount of gas that can be flared.

Upon completion of the well, all disturbed areas not needed for production facilities would be restored (see **Figure 2–5**). The drill pit would be dried and backfilled. Seeding of these areas would take place in the fall. On federal lands, facilities would be painted with agency-approved BLM colors to blend with surrounding landscape. Overall, the pad for a well during production is expected to be about 60 percent of the size that was needed for drilling and completion.

2.1.1.1.2.2.3 Unsuccessful Wells

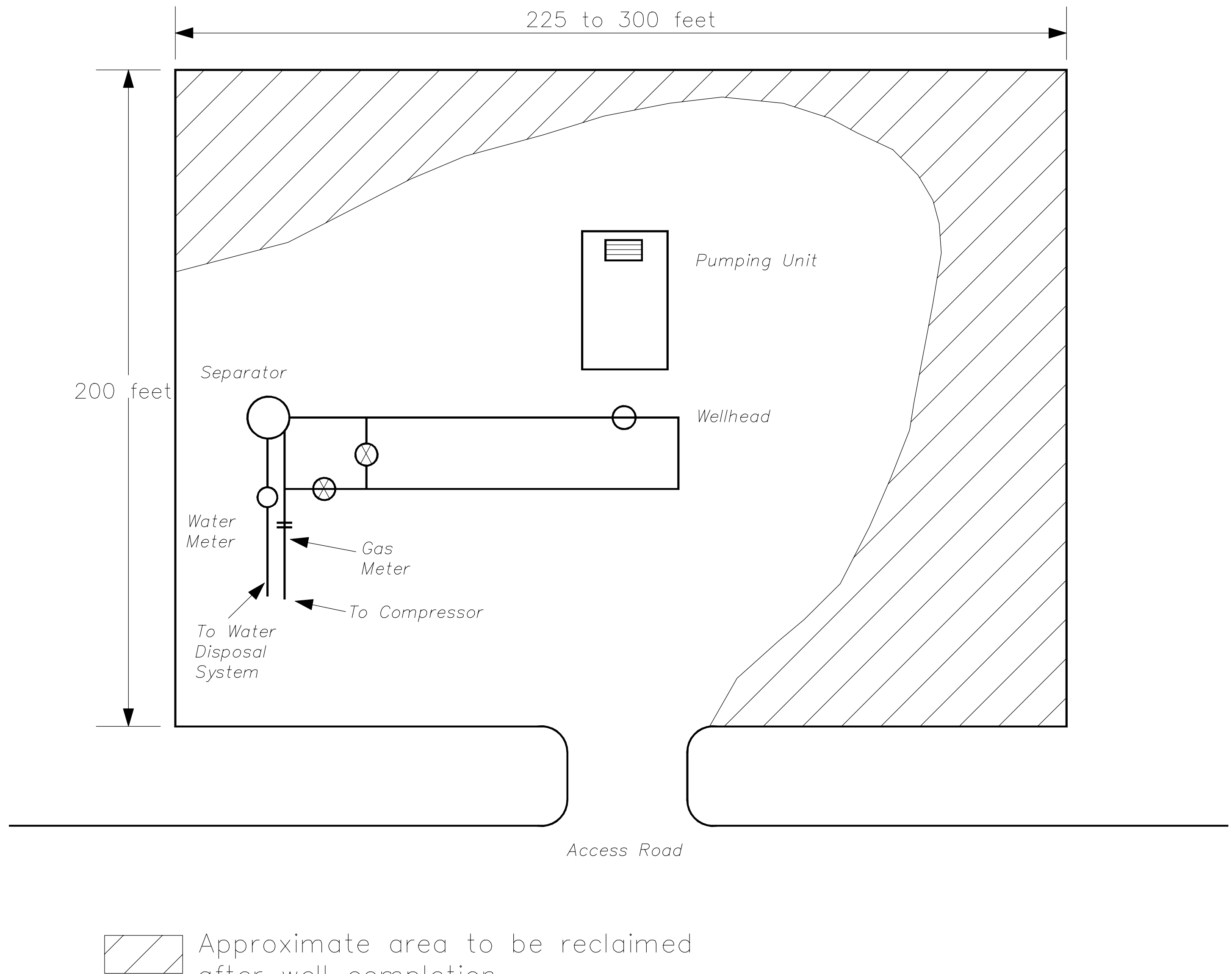
Unsuccessful wells would be reclaimed as described in **Section 2.1.1.1.4**.

2.1.1.1.3 Production/Maintenance Phase

2.1.1.1.3.1 Roads

Routine maintenance in the Project Area would occur on a year-round basis or as ground and site conditions permit. Summer (late spring to early fall) road maintenance would require gravel additions and/or blading consistent with "traveled road maintenance operations" in the area. Winter (late fall to early spring) maintenance would include blading of snow from access roads and some summer-like maintenance when necessary and permitted by weather conditions. During production and maintenance, the Companies would not routinely employ dust abatement procedures on all roads within the Project Area.

The counties and Companies would primarily be responsible for maintaining the project's roads in the Project Area. Under existing agreements between the BLM and the counties, Carbon and Emery counties maintain segments of BLM roads in the Project Area (**Plate 2–3**). Additionally, the counties would continue to maintain existing county roads. The Companies would maintain all other project roads.



Not To Scale

Figure 2-5
Schematic of a Typical Production Well Pad

Upon the project's completion, all roads constructed specifically for the project would be removed and reclaimed, unless specifically requested by the landowner. If a landowner decides to keep a road, then the landowner would accept responsibility for maintaining the road upon abandonment by the companies. The counties would continue to maintain existing county roads and any roads covered by maintenance agreements with the BLM.

2.1.1.1.3.2 Wells

2.1.1.1.3.2.1 Production

Installed surface production facilities would include the Christmas tree, a walking beam pumping unit, separator, gas and water metering facilities, and connections to the gas and water collection systems (**Figure 2–5**). All would occupy less than one acre.

The Companies propose to use walking beam pumps rather than progressive cavity pumps. The primary reason for not selecting the progressive cavity pumps is the coal fines present in CBM wells tend to plug up these pumps much more frequently than walking beam pumps. Thus, shut downs and maintenance would occur more frequently if the Companies used progressive cavity pumps. The pumping unit would be powered by a 30- to 100-horsepower electric motor or gas engine and would be used to lift the produced water from the production zone, allowing the gas to flow by reducing the hydrostatic pressure on the coals.

The produced fluid stream contains gas and water. Production of natural gas from coal seams in the Ferron Member was only recently initiated. Therefore, no long-term production history exists to definitively state trends in production performance in this area. However it is assumed that the production rate for each well should increase the first few years, then gradually decline. Based on a zero-time plot analysis used for predicting gas production, the estimated peak gas production for the Proposed Action is 60 billion cubic feet per year.

The produced stream requires separating water in a two-phase separator at the well site that would yield gas and produced water. Following separation the gas is metered and introduced into the gathering system for transport to a compressor facility. Separated, produced water would be transported via the produced water gathering system to approved disposal wells or evaporation ponds. The remaining on-site facilities on the surface are a reciprocating pump (walking beam unit), a vertical separator, and meter house to measure the gas volume. A free standing electric-powered computerized monitoring, control, and telemetry panel may be installed on selected wells.

2.1.1.1.3.2.2 Routine Maintenance

A maintenance person (a "pumper") would visit each well daily to ensure the equipment is functioning properly. Field personnel would routinely calculate balances between wells and collection/transfer points to ensure volumes match within acceptable tolerances. Significant leaks in gas or water pipelines would cause a loss of pressure detectable by the static pressure on the meter run. If such a leak is detected, a well would be shut-in. The shut-in point would be determined for each well based upon individual operating conditions. Field leaks would then be pinpointed using field pressures 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 on-site visits.

An off-site computerized monitoring system may be installed if warranted by the number of total producing wells and the cost effectiveness of installing electrical lines to each site. If installed, the automated monitoring system would allow monitoring of operations at each well. The system would monitor various operating conditions (gas and water production rates, pipeline pressure, separator pressure, etc.) to determine if abnormal conditions exist. The well site automation equipment power source would be provided by underground or aboveground electricity cables laid to the well site. The well site operating conditions would be transmitted via radio to a local central facility. If a problem is identified, maintenance personnel would be immediately dispatched to the well site. 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 may 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.

2.1.1.1.3.2.3 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 relief. Routine repairs would occur only during daylight hours and are usually completed within one day. Some limited situation may require several days to complete a workover. Although the frequency of workovers cannot be predicted because the requirements for workovers vary from well to well, each new well would likely require a workover during the first year of production.

2.1.1.1.3.3 Pipelines

Routine inspection of gas gathering and produced water pipelines would be done during the daily inspections of facilities. Procedures would be incorporated with the daily inspection of meters at the well sites. If pressure losses are detected, the wells would be shut in until the problem is isolated and rectified.

2.1.1.1.3.4 Electric Utilities

Routine inspection and maintenance of electric utilities would be done by Utah Power and Light.

2.1.1.1.3.5 Produced Water Disposal

2.1.1.1.3.5.1 Disposal Wells

Based on maximum production characteristics from CBM wells in the region, it is estimated that a well could produce about 350 barrels of water per day (BWPD) during the first year of production and then taper off to 300, 250, 200, and 150 BWPD during the second, third, fourth, and fifth years, respectively. After the fifth year, average water production should gradually taper off to less than 100 BWPD. There is reason to believe that the values could be much lower, but a maximum case analysis was used to ensure adequate capacity for disposal of produced water. Data from five of Anadarko's existing wells in the North Area suggested an average production of 63 BWPD in the first year, 58 BWPD in the second year, and 36 BWPD in the third year. Data from the South Area suggest an average production of 225 BWPD in the first year and 177 BWPD in the first ten months of the second year.

All disposal wells would be located on State or private land. The preliminary locations of the proposed disposal wells are shown on **Plate 2–1**. Disposal of produced water would occur in accordance with a plan approved by the BLM, as provided for in Onshore Oil and Gas Order No. 7, Disposal of Produced, and the Underground Injection Control permit program administered by UDOGM. If the capacity of the water disposal system is exceeded during any phase of the Ferron Natural Gas Project, the Companies would follow the appropriate procedures (UDOGM and Onshore Oil and Gas Order No. 7) to have additional Class II disposal wells approved and drilled and/or construct evaporation ponds.

Since operation began at Texaco's disposal wells (located in southeast ¼, Section 35, Township 18 South, Range 7 East and southwest ¼, Section 24, Township 18 South, Range 7 East), produced water has been deposited into the Navajo Formation. For the period July 1996 through April 1997, produced water was deposited at an average rate of 1,800 BWPD at approximately 750 pounds per square inch (psi). Texaco has recently perforated an additional section of the Navajo Formation and received permission from the UDOGM to inject at pressures as high as 1,750 psi. The wells have demonstrated the capacity to accept water at rates as high as 8,500 BWPD.

The proposed disposal wells would be completed into the Navajo Formation. Based on calculations with rates of disposal into the Navajo Formation and the thickness, porosity, permeability modeling conducted by Texaco and current disposal rates, each proposed well in the South Area should be capable of handling 8,500 BWPD.

The Companies have completed 53 wells in the South Area during the past several years and would drill 220 more, an average of 44 wells per year (across all land ownerships), over the five-year construction time frame. Therefore, by the end of the construction period, the maximum average daily water production rate would be 60,300 BWPD [(44 wells X 350 BWPD/well for the wells in the first year) + (44 X 300 for wells in the second year) + (44 X 250 for wells in the third year) + (44 X 200 for wells in the fourth year) + (44 X 150 for wells in the fifth year) + (47 X 100 for wells in the sixth and succeeding years). The projected disposal rate for Texaco's three proposed wells and Chandler's three wells is 8,500 BWPD for an overall capability of 51,000 BWPD. Texaco's two existing disposal wells would add a further 17,000 BWPD disposal capacity. Therefore, the proposed water disposal capacity of 68,000 BWPD would exceed the projected daily maximum water production rate (60,300 BWPD) by 7,700 BWPD.

Based on Anadarko's experience with rates of disposal into the Navajo Formation, the proposed disposal wells in the North Area should handle 10,000 BWPD. Anadarko's three disposal wells (one existing and two proposed) would be completed into the Navajo and Wingate Formations. Based on a projected disposal rate of 10,000 BWPD, the three disposal wells would have a capacity to dispose of 30,000 BWPD.

Through 1997, the Companies have completed 15 wells in the North Area and would drill 65 more, an average of 13 wells per year, over the five-year construction time frame. Therefore, by the end of the construction period, the maximum average daily water production rate would be 17,750 BWPD [(13 wells X 350 BWPD/well for the wells in the first year) + (13 X 300 for wells in the second year) + (13 X 250 for wells in the third year) + (13 X 200 for wells in the fourth year) + (13 X 150 for wells in the fifth year) + (15 X 100 for wells in the sixth and succeeding years). The projected disposal rate for Anadarko's three wells would be 30,000 BWPD. Therefore, the proposed water disposal capacity of 30,000 BWPD would exceed the projected daily maximum water production rate (17,750 BWPD) by 12,250 BWPD.

As described previously, emergency pits would be constructed and connected to each disposal well. If a disposal well fails and has to be shut down for repairs, the companies would use these pits for the short-term storage of produced water that would normally be sent to the disposal well. If the company cannot repair its disposal well before the emergency pit reaches capacity, pumps at the gas wells that are sending produced water to the emergency pit would be shut down until the disposal well is repaired. Once the disposal well is repaired, any water in the emergency pit would be pumped to the well for disposal. Emergency pits would not be used for permanent disposal of produced water.

The sizes and number of the emergency pits would vary by company. Most pits would range in size from 30 feet by 50 feet by 10 feet (capacity = 2,500 barrels of water) to 115 feet by 115 feet by 8 feet (capacity = 18,850 barrels of water). Disposal wells in the South Area would have an emergency pit associated with each of them on the CPF. However, in the North Area, one large emergency pit (capacity > 266,000 barrels of water) would service all three disposal wells. Specific differences among the Companies' proposals for emergency pits are discussed later in this chapter.

2.1.1.1.3.6 Compression

Presently, the Companies propose to use natural gas fired compressors at all locations. As development of the Project Area matures, the use of natural gas fired compressors may diminish and selected units may be replaced with electric-powered compressors. Because the likelihood and extent of this replacement are unknown, the impact analysis documented in this EIS assumed all compressors would be fired by natural gas.

The Companies would construct and operate seven new CPFs and three new compressor stations within the Project Area and one new compressor outside the Project Area on private land (**Plate 2–1**). Chandler has proposed three CPFs in the South Area. Two would be rated at 2,200 HP and one at 850 HP. Texaco has proposed three new CPFs in the South Area with all three rated at 4,000 HP. Anadarko has proposed one CPF and three compressor stations within the North Area with two 1,700 HP units at each location. One CPF and all three compressor stations would be within the Project Area and the second CPF would be located south of the North Area on private land. Anadarko's one existing compressor, rated at 1,015 HP, is operating in the North Area (on State land) and would be upgraded to 3,400 HP. This compression capacity would be sufficient to accommodate the volume of natural gas expected from the wells operating in the Project Area.

Amine units and Glycol Dehydration units would also be installed at each compressor site. The function of the amine units is to reduce the quantity of carbon dioxide in the gas stream to the levels that must be attained for transport to the Questar transmission pipeline for commercial sale. Dehydration units would be used to reduce the water in the gas stream to likewise acceptable levels for commercial transportation. Anadarko would install amine units and dehydrators at each of their proposed compressor stations. Both units would accommodate a design flow rate of 15 million cubic feet of natural gas per day (MMcfd). Chandler would install the units at each of their two proposed compressors with the capability to process 10 MMcfd. Texaco would install units with the capability to process 15 MMcfd at each of their three proposed compressor stations. Both amine and dehydration units are discussed in more detail in **Section 4.3**.

2.1.1.1.3.7 Chemical Use

Under the Proposed Action, the Companies would use a variety of chemicals, including solvents, lubricants, paints, and additives. The chemicals the Companies may produce, use, store, transport, or dispose of as a result of the project are identified and discussed in the Hazardous Substances Management Plan, which is included as **Appendix B** of this EIS. The Plan also identifies which substances are considered hazardous or extremely hazardous.

2.1.1.1.3.8 Waste Sources and Controls

A variety of waste, including drilling solids, steel drums, waste oils, spent oil filters, waste parts, cleaning solvents, spent water filters, waste triethylene glycol, and spent glycol filters would be produced during the drilling and production phase. All wastes described in this section would be recycled or disposed of in accordance with applicable current laws and regulations.

Solids or cuttings would be produced during the drilling stage. The cuttings are the bits of rock produced by the drill bit cutting through the drilled interval. The solids would be buried in the drilling pit after fluids, such as water, treatment fluids, and frac fluids, have evaporated or been pumped into trucks and transported to approved disposal facilities.

Emptied steel and plastic drums that had contained materials such as caustic soda, citric acid, lubricating oil, methanol, and drilling additives would require appropriate disposal or recycling. Empty metal or plastic drums would be returned to the supplier of the product. The Companies may rent drums from the suppliers and should be able to return the drums to the suppliers for refills.

Waste lubricating oil generated at the compressor stations and production sites would be disposed of by a contractor. Some fluids would be generated at compressor stations during pipeline cleaning operations, referred to as pigging. This fluid would be stored in a 50 gallon sump tank. The contents of the tank would be removed by a contractor using a vacuum truck and would then be transported to a permitted disposal/ recycling site.

Each compressor station would create an additional oil waste product through the bypass system. This waste would be a combination of about 90 percent water and 10 percent light hydrocarbons. This compressor bypass fluid would be piped to the 50-barrel sump tanks as discussed above.

Solid wastes generated at the compressor stations would include spent gas filters and cleaning rags that would be handled as general trash and sent to the regional landfill. Spent oil filters from the compressor lubrication systems would be removed and disposed of in an approved disposal facility.

Several waste streams would be generated from the triethylene glycol dehydration line at the compressor stations. The dehydration units remove water from the gas stream by contacting the gas with triethylene glycol. The glycol would be regenerated through the application of heat. The water would be “boiled off” and released as steam.

As necessary, triethylene glycol and amine fluids would be replaced due to the excessive accumulation of contaminants. An approved contractor would remove the spent glycol or amine fluids and replace fresh triethylene glycol or amine fluids in the system. On occasion, the Companies may remove the spent glycol or amine fluids and temporarily store the glycol or amine fluids in drums. This glycol and amine fluids would also be removed by an approved contractor.

In addition to the spent glycol, spent sock and charcoal filters would also be used in the dehydration process. These filters would be changed approximately every other month and the spent filters would be placed in general trash for disposal.

Sanitary wastes would be collected in portable toilets located on well pads during drilling and completion. These toilets would be pumped by the contractor regularly. When drilling and completion of the well are finished, the toilets would be removed by the contractor.

Construction materials and trash would be transported to approved disposal areas. General trash would be collected in covered containers and periodically transported to approved disposal areas.

2.1.1.1.4 Decommissioning/Reclamation Phase

The Proposed Action assumes each well would produce during its approximate 20-year economic lifetime. The reclamation of dry holes would follow the procedures described below with the exception that reclamation would begin as soon as possible after the determination is made that the well would not be an economic producing well. The following briefly describes the procedures that would be addressed to reclaim the disturbance to as near as possible to pre-development conditions.

2.1.1.1.4.1 Roads

Access roads would be reclaimed by plowing and seeding unless the landowner and/or land manager wishes to make use of any roads and accepts responsibility through execution of a release for future road maintenance. Roads 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 SITLA. 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 disturbance would be reseeded with a seed mixture authorized by the Approval Officer, as described in the Reclamation Plan (**Appendix A**). 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 prior to purchase. Commercial seed would be either certified or registered seed. Seeding and/or planting would be repeated until satisfactory revegetation is accomplished.

2.1.1.1.4.2 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 UDOGM rules. Once the well is conditioned as a static column, the well would be decommissioned by placing redundant plugs, a slurry of cement and water, at strategic locations in the well bore. These locations would be based upon each well's configuration, but would be placed to prevent the migration of fluids 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 Reclamation Plan (**Appendix A**).

2.1.1.1.4.3 Gas and Water Pipelines

The procedures for decommissioning and reclaiming pipelines depend on whether the pipeline is underground or aboveground. Underground pipelines would be cleaned, disconnected, and then abandoned in place to avoid any extra surface disturbance as noted in the Reclamation Plan (**Appendix A**). Aboveground pipelines would be cleaned, disconnected, and removed. Any surface disturbances associated with each aboveground pipeline's removal would be recontoured to approximate the original contours, seeded, and mulched using procedures described in the Reclamation Plan (**Appendix A**).

2.1.1.1.4.4 Electric Utilities

Underground electric lines would be disconnected and abandoned in place to avoid any extra surface disturbance. Above ground 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 Reclamation Plan (**Appendix A**).

2.1.1.1.4.5 Produced Water Disposal

2.1.1.1.4.5.1 Disposal Wells

Disposal wells would be abandoned and reclaimed in the same manner as production wells.

2.1.1.1.4.6 Central Production Facility

Underground pipelines leading to the CPF would be cleaned, disconnected, plugged, and abandoned in place. All aboveground facilities and equipment, including the compressor, amine, and dehydration units and buildings, would be disassembled and removed from the site. The CPF would be recontoured as close as possible to original conditions. Reseeding would then be conducted using the methods described in the Reclamation Plan (**Appendix A**).

2.1.1.1.5 Safety/Emergency Response

This section describes the methods that the Companies would employ to ensure a safe operation of the natural gas wells during development and production. It also describes how the Companies would respond to emergency situations.

2.1.1.1.5.1 Geologic Hazards

During drilling operations, abnormally-high pressure (blowouts) could occur. However, more than 100 CBM wells have been drilled in the Price area with only two instances of abnormally-high pressure. All wells drilled would be required to have Blowout Prevention Equipment (BOPE) installed to control any abnormal pressures encountered. Blowouts are considered highly unlikely because of the BOPE, shallow well depths, normal formation pressures, and past experience in the Ferron Sandstone Member.

H_2S has not been encountered to date during drilling in any of the more than 100 CBM wells drilled in the Price area. However, H_2S has been detected in produced water from some of the CBM wells in small amounts (80 to 90 ppm below the minimum level of 100 ppm at which it is regulated under Onshore Order No. 6). Solution H_2S was also recently encountered in the drilling of a disposal well to a depth of approximately 6,000 feet into the Navajo Formation. As a result, the Companies would prepare an H_2S contingency plan in accordance with UDOGM's requirements.

2.1.1.1.5.2 Fires and Explosions

The potential for gas flowline or pipeline leaks or ruptures would exist. Most ruptures are the result of heavy equipment accidentally striking the pipeline while operating in close proximity. Such ruptures could result in an explosion and/or fire if a spark or open flame would ignite the escaping gas. Pipeline design and materials would be conducted in accordance with applicable standards to minimize the potential of a leak or rupture. Frequent signing along the pipelines would reduce the risk of accidental ruptures from excavating equipment. Additionally, the Companies would monitor the pipeline flow by either remote sensors or daily inspections of the flow meters. This would reduce the probability of ruptures by prompt detection of leaks.

Well fires are very rare, but could occur under certain conditions. For the reasons listed in the previous sections, the probability of a blowout is very low. However, if a fire would occur, the Companies would contract one of the several companies specializing in controlling well fires as part of their Emergency Plan.

2.1.1.1.5.3 Public Safety

The Companies would take measures to protect the public from hazards at well facilities. All CPFs would be fenced. Pumping units would have guard railing to prevent people and large animals from being injured by moving parts according to the Occupational Safety and Health Administration (OSHA) regulations and the Authorized Officer. Warning signs would be placed around all facilities.

2.1.1.1.5.4 Employee Safety

The Companies would develop Emergency Plans that would cover all potential emergencies to include fires, employee injuries, chemical releases, and H_2S releases, among others. The Plans would include phone numbers for all medical and emergency services, and the people to contact in event of emergency situations. The Plans would be posted at all local Company offices and field facilities. All employees and subcontractors would be trained on matters concerning the Emergency Plan when they would be hired, and refresher courses would be presented annually.

In addition, the Companies would not allow firearms to be brought into the area by on-duty employees and contractors. They also would train employees and provide written notification to contractors not to harass local wildlife.

2.1.1.2 Company Breakdown of Proposed Well field Development

This section describes the features of the Proposed Action that would be specific to each Company involved in the Proposed Action. The general methods of well field development, production, and reclamation are generally the same for all three companies. The major differences would be the amount of development and the type of facilities to be constructed.

2.1.1.2.1 Anadarko

Anadarko would develop wells in the North Area only. Anadarko's Proposed Action is to develop 65 new natural gas wells during the first five years of the project. Anadarko is proposing well pads with an areal extent of 200 feet by 300 feet or 1.37 acres. They are also proposing to build five new gas compressors and two new disposal wells. Anadarko has no plans to install a remote monitoring system. As a result, Anadarko would inspect all wells and facilities on a daily basis.

As mentioned previously, Anadarko plans to use a single large pit for storing produced water when one or more disposal wells may not be operating. All of Anadarko's disposal wells would be connected to this emergency pit so produced water could be routed to it if needed. This pit in T14S R10E Section 3, which was originally constructed as an evaporation pond, encompasses about 3.7 acres (400 feet wide by 400 feet long by 10 feet deep). The pit's overall capacity exceeds 266,000 barrels of water.

As with the other companies, if Anadarko cannot repair its disposal well or wells before the emergency pit reaches capacity, pumps at the gas wells that are sending produced water to the emergency pit would be shut down until the disposal well is repaired. Once the disposal well is repaired, any water in the emergency pit would be pumped to the well for disposal.

For development wells in an area with existing infrastructure, the following is Anadarko's typical testing scenario. After wells are fractured and stimulated, water would be pumped/flowed to the reserve pit for approximately 30 days. During the first two weeks of this period, typically only water would be produced. Over the next two weeks, as the fluid level in the wellbore is reduced, the production of gas slowly would increase from ten thousand cubic feet per day (Mcfd) up to 100 Mcfd on average. In most cases, a gathering system would be installed within this 30 day period and the gas would no longer be vented. Water may continue to be pumped to a pit until a water gathering system is installed and/or volumes are reduced. If the volume of water present in the pit approaches the reserve pit's capacity, Anadarko would pump the water into a truck for transport to and disposal in a disposal well.

For remote wells (step out or exploratory) where infrastructure is not in place, a longer testing period is required to determine the well's economic potential. The same process as described above would occur, but typically would require up to 90 days to evaluate the capacity of the well. Venting and flaring beyond 30 days would require approval per NTL 4–A and UDOGM Permit to flare gas. The longer period of time would be required to determine if the gas recovery rates will justify the expenditures needed for the project to be viable.

The above information is an average for a typical completion. However, the average time may vary depending on well performance and other factors such as weather, equipment availability, etc.

2.1.1.2.2 Texaco

Texaco would develop wells in the South Area only. Texaco's Proposed Action is to develop 137 new natural gas wells during the first five years of the project. Texaco is proposing to build wells with pads that would be 225 feet by 200 feet or 1.03 acres in size. Texaco would also install four compressors and four disposal wells. Texaco is planning to install a remote monitoring system for its well field. As a result, they may inspect all wells and facilities on an approximate weekly basis. However, daily visits to wells and facilities may be required to maintain an efficient and safe operation.

2.1.1.2.3 Chandler

Chandler would develop wells in the South Area only. Chandler's Proposed Action is to develop 87 new natural gas wells during the first five years of the project. Chandler is proposing 300 feet by 160 feet (1.1 acres) well pads, three compressors, and four disposal wells. Like Anadarko, Chandler has no plans to install a remote monitoring system. As a result, Chandler proposes to inspect all wells and facilities on a daily basis.

Additionally, Chandler has applied to unitize a portion of the South Area under regulations contained in 43 CFR 3180 — Onshore Oil and Gas Unit Agreements. Unitization provides for the exploration, development, and operation of a geologically defined area by a single operator so that drilling and production may proceed in the most efficient and economical manner. A unit agreement is an agreement approved by the Authorized Officer of the BLM, submitted by an operator on behalf of the owners of oil and gas interests over a potential oil or gas reservoir who wish to unite with each other to facilitate the orderly and timely development of the oil and gas resources within the unit area. **Figure 2–6** shows the location of Chandler's proposed unit.

Approval of the unit agreement does not, in itself, authorize any on-the-ground activities. All such activities are permitted on a case-by-case basis through this EIS and the Application for Permit to Drill (APD) and Sundry Notice processes (see 43 CFR Part 3160 and the Oil and Gas Onshore Orders). Unitization serves the public interest in that it promotes the exploration of unproven acreage and permits the BLM to exercise more effective control over drilling activity in a large area.

2.1.2 Transmission Pipeline

Questar proposes to build a transmission pipeline in the Project Area. This pipeline would extend a pipeline that was considered in the Price Coalbed Methane Project (now referred to as Jurisdictional Lateral #102 [JL102]) approximately 27 miles. The new 20-inch diameter pipeline would start in Section 26, Township 16 South, Range 9 East, about 5 miles northeast of Huntington and extend southwest terminating in Section 15, Township 20 South, Range 7 East. It would follow Questar's existing pipeline (JL44) for the entire route. The proposed pipeline location is shown on **Plate 2–1**. The pipeline would require a 50-foot permanent ROW width and a 30-foot wide temporary use area (**Figure 2–7**). All construction activities would occur inside the limits of the ROW and temporary use areas. The life of the pipeline is projected to be 50 years. The projected life may vary as it depends on natural gas demand. The pipeline would be abandoned in place after the termination of its viable life.

Questar's internal pipeline construction standards would apply. All facilities would be constructed in accordance with the Department of Transportation regulations described in 49 CFR Part 192. The pipeline would be designed, constructed, and operated in compliance with the Occupational Safety and Health Act. The pipeline would consist of 20-inch outside diameter (OD) steel pipe with a 0.25-inch wall thickness and manufactured from American Petroleum Institute 5L–X52 steel. The pipe would have an external anti-corrosion coating of 12 to 14 millimeters applied at a coating facility under controlled conditions.

2.1.2.1 Construction Phase

The pipeline would be constructed in a single spread consisting of equipment and crews handling various phases of construction activities along the route. Construction of the pipeline would generally follow standard pipeline construction methods. Prior to construction, the centerline and the exterior ROW boundaries would be staked and left marked for the duration of construction. The pipeline would be buried with a minimum cover of 40 inches, except where bedrock is encountered at a lesser depth. Where bedrock is found, the pipe would be buried with a minimum cover of 24 inches.

Installation of the pipeline would be modified somewhat at crossings of streams, such as Huntington and Cottonwood creeks, and dry washes. The basic methods (trenching) used would remain unchanged. However, the depth of the pipeline would be increased. At both live streams and dry washes, the pipeline would be buried eight feet below the bed of the stream or wash. Additionally, material excavated from the beds of live streams would be stored on the streambanks and used as backfill. Construction of the crossings would be timed to minimize the time the trench is open, minimize concurrence with high flows, and minimize effects on aquatic species.

2.1.2.1.1 ROW Clearing and Excavation

On lands supporting shrub-type vegetation cover (e.g. sagebrush, salt bush), the ROW would be cleared by "scalping" off the tops of brush plants with a motor grader or a bulldozer. Vegetation cover types such as grasses or other low growth vegetation would not be cleared except in areas directly over the trench or where grading would be required. Brush and rocks cleared from the ROW would be windrowed or piled on one side of the ROW for later use in reclamation. The ROW would then be leveled. In areas where rugged topography with steep side slopes cannot be avoided, a level working pad would be cut from the hillside with a bulldozer (see **Figure 2–8)**.

After the ROW would be cleared, ditching would be conducted with a wheel ditcher, saw trencher or backhoe. Topsoil material would be salvaged along areas specified by either the land managing agency or the landowner where it can be saved.

During construction of access roadways, Questar would comply with all crossing requirements of the state or county where the road is located. Roadways would be bored or open cut, depending on the determination of the jurisdictional agency. Typically, dirt or gravel surfaced roads would be open cut and the pipeline crossing completed within one day. Crossings at heavily traveled roads would likely be made by horizontal boring at a minimum depth of 5.5 feet beneath the road surface.

In areas where surface or subsurface rock is unrippable, blasting for grade or ditch excavation would be necessary. A blasting plan would be submitted for approval prior to blasting activities.

In applicable areas, care would be taken to prevent damage to underground structures (cables, conduits, pipelines) or to springs, water wells or other water resources. Blasting mats or soil cover would be used on all blasts to prevent the scattering of loose rock. Landowners or tenants in close proximity to the blasting would be notified in advance. Before blasting, the affected area would be checked to ensure that all people are out of the blasting danger area. Where blasting would occur adjacent to roads, flagmen would be stationed to control traffic and protect people. Blasting would not occur within ¼ mile of live springs, water wells or reservoirs without prior approval from the authorized agency.

2.1.2.1.2 Pipe Insertion and Testing

After ditching is complete, the pipe sections would be strung along the trench, bent to fit the contour of the trench, aligned, welded together, inspected, coated, and placed on temporary supports along the edge of the trench. The pipe assembly would then be lowered in to the trench by side-boom tractors and backfilled. After backfilling, the pipeline will be either hydrostatically tested or gas tested to verify the integrity of the pipeline. If water is used, test segments will be determined by topography and water availability. Questar probably would purchase water for hydrostatic testing from local water users. After testing a segment, the water may be pumped into the next test segment. However, all water used for hydrostatic testing would ultimately be disposed of in accordance with applicable regulations.

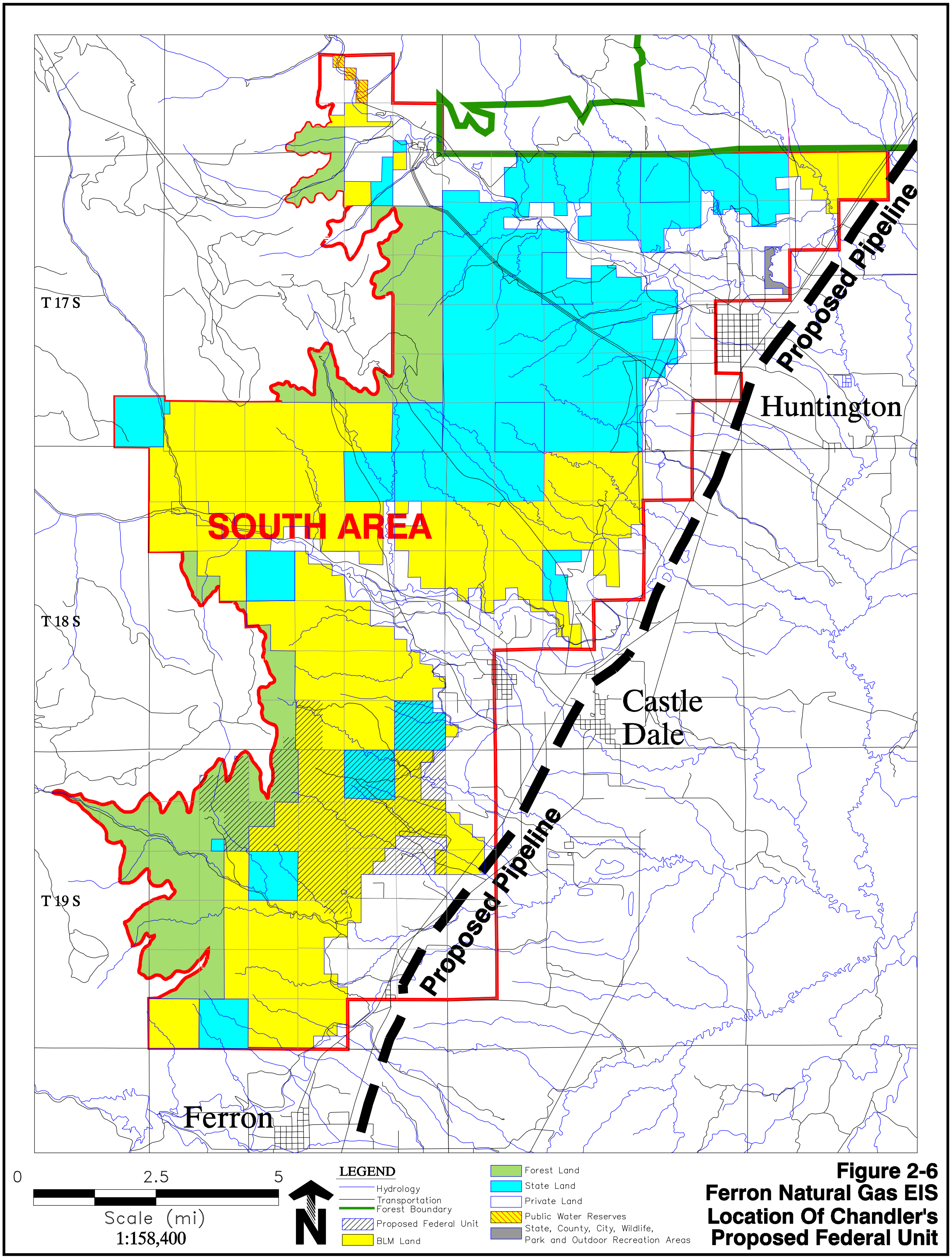


Figure 2-6
Ferron Natural Gas EIS
Location Of Chandler's Proposed Federal Unit

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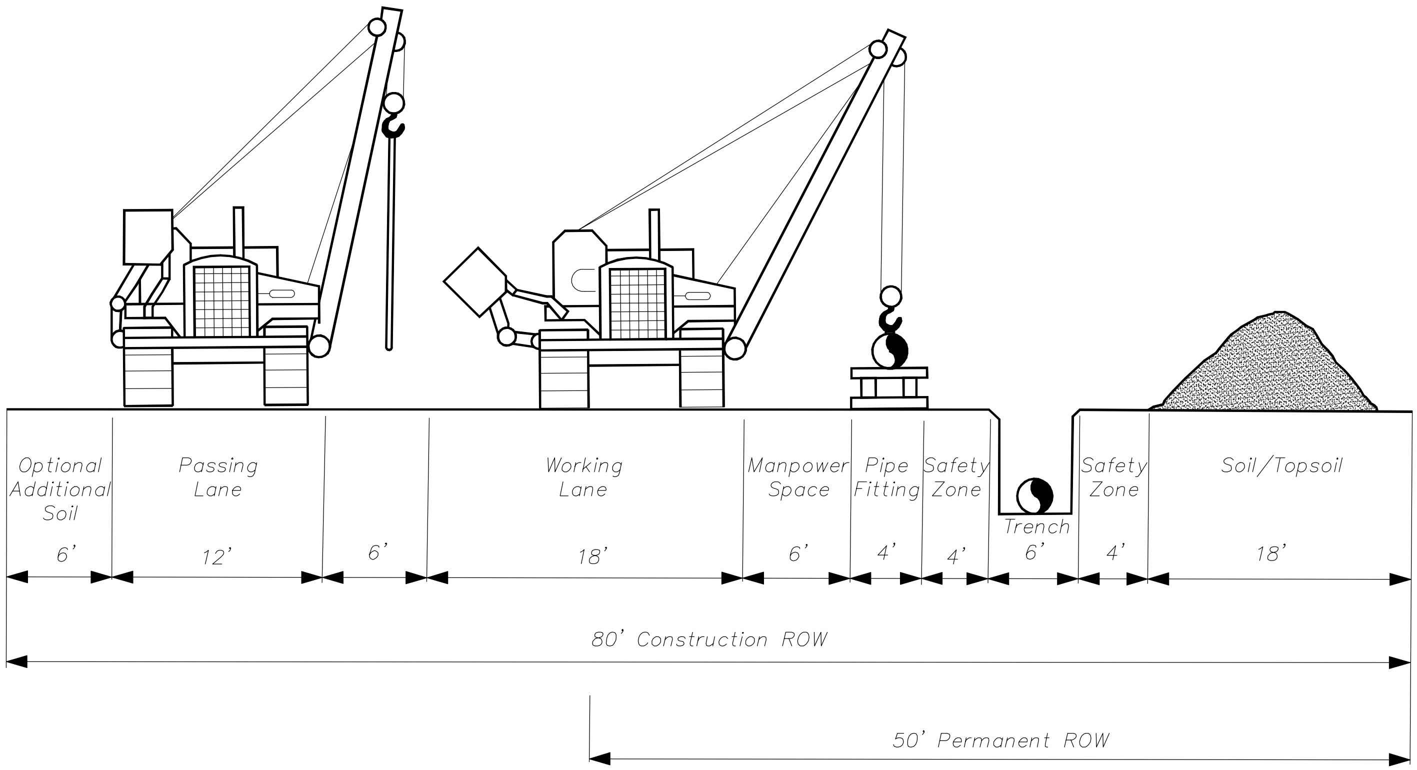

Not To Scale

Figure 2-7
Transmission Pipeline ROW
Typical Cross-Section

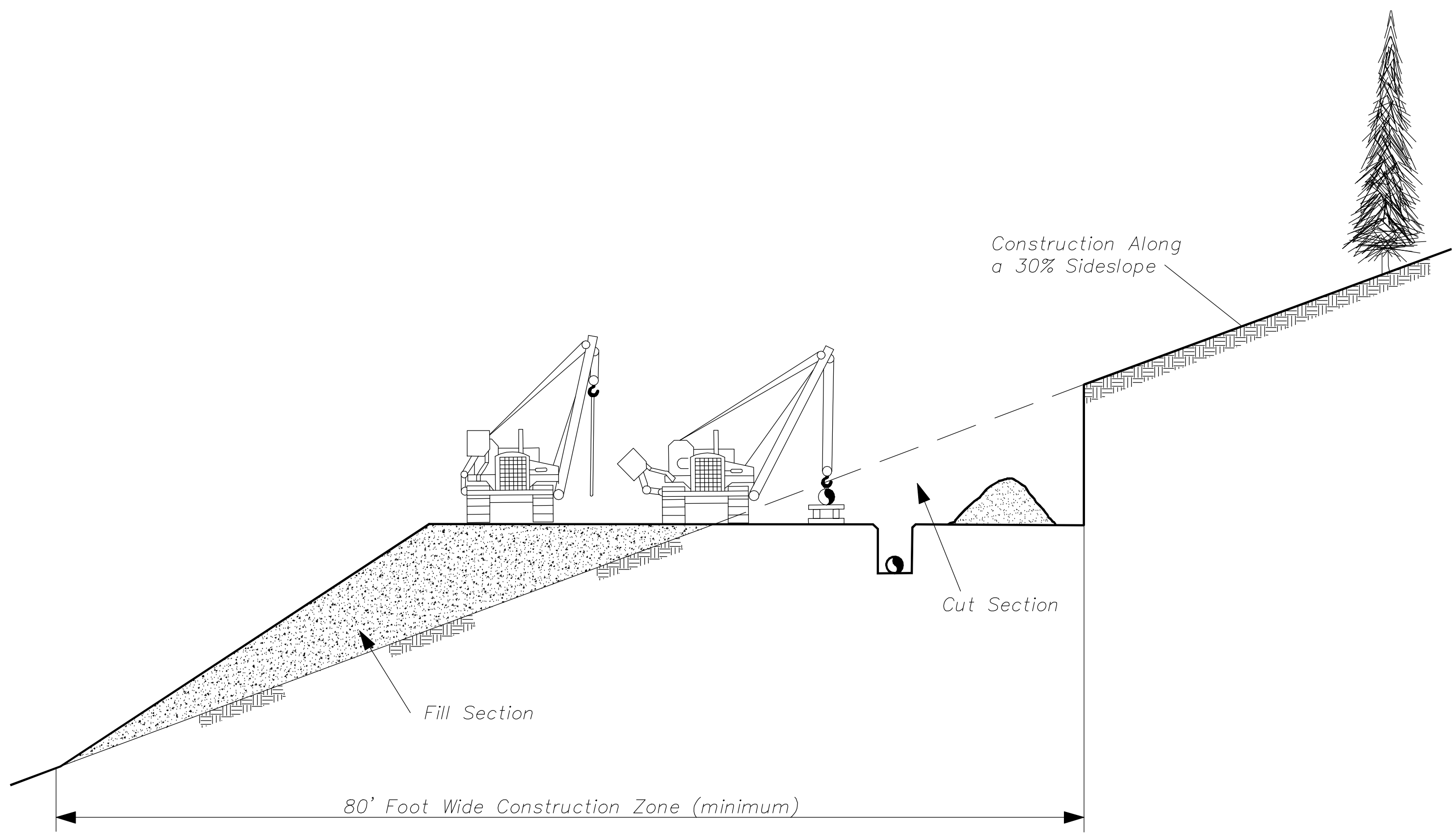

Figure 2-8
Transmission Pipeline ROW
Typical Slope Construction

Not To Scale

2.1.2.1.3 Work Force

The work force is anticipated to include 75 people. The pipeline construction crews would include equipment operators, welders and laborers. Questar anticipates that approximately 25 percent of the total work force would be made up of people from Carbon and Emery counties. The remaining work force would be from various parts of the country.

2.1.2.1.4 Cleanup and Reclamation

Following the backfilling operation, cleanup and reclamation of the ROW would be accomplished. The backfilling would be completed using the spoil previously excavated from the ditch. The topsoil would then be redistributed back over the ROW. The ditch would be compacted as much as possible over the pipe during backfilling. The disturbed surface would be graded and restored, as near as practicable, to the original contour of the land. Restoration would include moving fill material back into the sidehill cuts that were made during construction.

Water diversions would be constructed as needed to control surface water and erosion. To accomplish this, waterbars would be constructed on a contour across disturbed areas. All such structures would be built to simulate the imaginary contour lines on the slope, and to drain away from the disturbed area and continue across the ROW so that water is carried onto adjacent vegetation. Waterbars would be constructed at the following general spacing intervals:

Grade (percent)	Spacing (feet)
5–15	300
16–30	200
>30	100

Vegetation and rocks would not be permanently windrowed along the edge of the ROW. Brush and other woody material cleared from the ROW would be randomly scattered over the ROW and temporary use areas. Rocks cleared from the ROW would be buried either on the ROW, used to construct rimrock, strategically placed as barricades across the ROW to deter use as a road, or randomly scattered across the ROW as directed by the applicable land manager. The density of surface rocks would be comparable with adjacent disturbed land.

Restoration of washes would entail removing all debris from the stream bed and restoring the banks as nearly as possible to the original contour. Surplus soil would be spread on the ROW adjacent to the crossing.

Disturbed areas would be reseeded with a seed mix prescribed by the permitting agency. There would be no noxious weeds in the mixture. Seed would be tested in accordance with applicable regulations. Commercial seed would be certified and used within 12 months of testing to assure seed viability. The seed mixture container would be tagged in accordance with state laws.

Compacted soil conditions would be relieved before seeding. Seed would be applied by a range type drill or like service. The seed would be drilled in rows up to a maximum of 4 to 10 inches apart and at a depth of not less than ½ inch or more than one inch. If broadcast or hydro seeding methods would be used, seeding rates would be doubled. Seeding would be repeated in two growing seasons if a satisfactory stand is not established as determined by the BLM. Approved mulch application would be used in sensitive areas if required to control erosion. The type and application of mulching materials would be determined by the site inspection and consultation with the BLM.

2.1.2.2 Operation Phase

After the transmission pipeline is tested and commissioned, the Companies would connect the high-pressure gas pipelines (4 to 10 inches OD) from their CPFs Questar's transmission pipeline. Questar would require that the gas would arrive at the metering building at a pressure sufficient to transport the gas. The connections would be housed in a small metering building. Equipment would be installed in the building to measure the volume, quality, temperature and pressure of the gas arriving from the central processing facilities. These fully automated measurements would be continuously transmitted via microwave signal to Questar's field office in Price and to the Questar's headquarters in Salt Lake City. Thus, the telemetered readings would permit Questar to continuously monitor the pressure of the gas stream. Any deviations from operational standards that may include potential leaks in the system would be detected in a timely fashion. At that point, Questar would be able to quickly isolate any problems and quickly take corrective actions.

2.1.2.3 Decommissioning/Reclamation Phase

The life of the pipeline is projected to be 50 years, depending on the demand for natural gas. The pipeline would be abandoned at the end of its viable life. Reclamation, described in the Construction Phase section, would begin as soon as possible after the pipeline is commissioned. The pipeline would be purged, cleaned, sealed and secured as described in the Reclamation Plan (**Appendix A**). The line would be abandoned in place, but all aboveground facilities would be removed. All disturbed areas would be rehabilitated, to the extent possible, to their pre-construction condition. Abandonment would result in the reversion of the ROW back to private landowners or the managing agency.

2.2 ALTERNATIVE 2 — PROPOSED ACTION WITH ADDITIONAL ENVIRONMENTAL PROTECTION MEASURES

This alternative was developed in response to issues raised during the public and agency scoping process. This alternative would incorporate the same construction and operational components as the Proposed Action with additional environmental protection measures applied to those actions taking place on federal lands. None of the environmental protection measures described in this alternative would disallow lawful access to develop a lease, but they may require relocation of well pads, roads, or ancillary facilities within the lease, restrict development during certain periods of the year, or require special construction and operational methods to reduce potential environmental impacts. The additional measures included in this alternative are listed below.

Water Resources

- Avoid surface disturbance within 330 feet of the centerline or within a designated 100-year floodplain of perennial streams.

- Avoid surface disturbance within 660 feet of springs, whether flowing or not.

- Avoid blasting or geophysical drilling within 0.25 mile of a spring or water well.

Soils

- Avoid construction on frozen or saturated soils. The Authorized Officer (BLM or FS) will determine what is wet, muddy, or frozen based on weather and field conditions at the time. This does not apply to maintenance of existing roads and wells.

- Exclude road and pad construction on slopes in excess of 25 percent. Pipeline construction on slopes in excess of 25 percent would be determined on a site-specific basis.

- On critical soils, avoid construction on slopes greater than 6 percent. Where construction cannot be avoided, operations and facilities will be located to reduce erosion and improve the opportunity for revegetation.

- New roads will be constructed to avoid critical soil areas, where possible. Where roads must be allowed, new roads will be constructed in accordance with agency-specified design standards to minimize watershed damage.

- On critical soils, avoid road grades greater than 10 percent. The Authorized Officer (BLM or FS) may allow grades in excess of 10 percent with a maximum length of 1,000 feet. No road grades in excess of 15 percent will be allowed.

- On critical soils, pipelines will avoid slopes in excess of 15 percent.

Vegetation

- In accordance with a weed control plan developed for this project (**Appendix C**), treat and control noxious weed infestations within 100 feet of disturbed areas associated with well sites and facilities and roads or rights-of-way constructed or improved by the Companies, to the extent the infestation is caused by the Companies.

Wetlands/Riparian

- Avoid construction, development, and rights-of-way within 220 feet of the boundary of riparian areas. Where these areas must be disturbed, minimize impacts and perform post-disturbance reclamation.

Reclamation

- All project roads designated for reclamation (or partial reclamation) and all well sites, facility sites, and pipelines shall be reclaimed (recontoured and reseeded) in the fall season or at a period specified by the Authorized Officer.

- Disturbed areas will be restored to approximately the original contour.

- Reclamation on sites with critical soils will be graded using slopes of 5 percent or less where feasible and grading the site so as to collect water for revegetation. Site-specific evaluation by the surface managing agency may allow for modification to this standard.

Wildlife

- Selected roads in big game winter range habitats shall be gated and signed. The gates shall be locked during the critical period for wildlife (December 1 to April 15). The gate locations shall be determined by the Authorized Officer for the BLM in consultation with Emery or Carbon counties. A cooperative agreement will be developed to detail maintenance responsibilities, design of gates, and contingency methods for excessive vandalism to the gates. The BLM shall provide the verbiage for the signs, which shall explain the reasons for the seasonal closure and agencies participating in the closure shall be identified.

- In elk and mule deer winter range (crucial and high priority), exploration, drilling, and other development shall occur only during the period of April 16 to November 30. This shall not apply to maintenance and operation of producing wells. Exceptions to this limitation in any year shall be requested in writing to the Authorized Officer of the BLM or Forest Service.

- In elk and mule deer crucial winter range, all non-emergency workover operations, as defined in this EIS, shall occur only during the period April 16 to November 30. The proponent shall provide notice for all emergency work requiring use of heavy equipment during the winter period (December 1 to April 15). The notice shall be provided within five days of the work.

- Minimize the number of actual visits by personnel needed to monitor well operations.

- Reclamation on big game crucial winter range will include hand planting of seedling browse plants and use of seedling protectors.

- In order to provide winter range protection for mule deer and elk, avoidance areas would be created in big game wildlife corridors on Federal lands. The big game corridors (shown on **Plates 3–5** and **3–6**) include drainages and critical areas within winter range habitat. Under existing regulations (43 CFR 3101.1–2) and lease rights, BLM would relocate wells, roads, or facilities within the boundary of the proposed 160-acre legal subdivision of a lease to minimize surface disturbance and/or surface occupancy within the designated big game corridors. It is recognized that in some instances, wells, roads, and facilities would be located within the big game corridors. Evaluation of the need to relocate any facility would be conducted during the site-specific, on-site evaluation of a proposed well at the time an APD is submitted. BLM shall not identify relocation of facilities that would result in a well being situated off the lease or outside the 160-acre legal subdivision. BLM would not recommend relocating wells, roads, or facilities outside the corridors in those circumstances where useable roads already exist. With corroboration by BLM geologists, BLM would not recommend relocation of wells that would prevent the proponent from hitting a specific geologic target with regard to presence and alignment of known fault lines. Wells, roads, or facilities would not be relocated to a position that would be more environmentally damaging or exceed provisions of this EIS or appropriate land use plan. The Companies may choose to alter the location of wells adjacent to the big game corridor to achieve desired drainage of gas and water resources.

- To offset direct impacts to mule deer and elk, when disturbance exceeds 10 acres in elk or mule deer winter range (crucial and high priority), an equivalent acreage of adjacent habitat will be enhanced to accommodate increased use by the animals. The habitat enhancement will be completed commensurate with the surface disturbing activity. All costs associated with project planning through completion shall be the obligation of the lessee. To satisfy this mitigation provision of the governing land use plans, the companies and BLM have agreed to establish a Wildlife Habitat Mitigation Fund that includes provisions for monetary contributions of $1,301.26 (1998 dollars) per well on Federal surface/subsurface ownership in big game crucial and high priority winter range. This mitigation fund would be used to complete habitat enhancement projects to directly benefit wildlife by being used within the herd unit affected. Administration of this fund, including objectives for habitat enhancement, would be formalized in an agreement developed between the proponents, BLM and the UDWR.

- Individual companies will attend yearly meetings with BLM to coordinate and organize APD processing for yearly drilling plans of the companies to assure that expected reworking of newly completed wells occurs before the winter closure period.

Special-Status Species

- Avoid temporary surface disturbance and occupancy (i.e., seismic lines and pipeline, power line, and project construction) within one-half mile of active raptor nests during the critical nesting period (February 1 to August 15). Site-specific evaluation in coordination with the USFWS and UDWR may allow for modifications. This mitigation does not apply to maintenance and operation of existing wells and access roads constructed prior to occupancy of the nest.

- Permanent surface disturbance and occupancy shall be prohibited within 0.5 mile of raptor nests that have been documented as occupied within the 3-year period proceeding construction. Site-specific evaluations in coordination with USFWS and UDWR may allow for modifications to this requirement.

- Permanent surface disturbance and occupancy shall be prohibited within 1.0 mile of peregrine falcon eyries. Section 7, Endangered Species Act consultation with USFWS shall be required for modifications to this requirement.

- Perform raptor surveys to determine the status of known nests and to verify the presence of additional nests for all federal leases within the Project Area. Surveys shall be conducted by consultants qualified to conduct such surveys and approved by the BLM's Authorized Officer. All surveys shall be conducted by helicopter during May of each year, prior to the proposed drilling and prior to APD approval. The surveys shall be done in the same year as the proposed drilling so the current nest activity status data are available. Costs for the survey and preparation of a report of the findings of the survey shall be borne by the lease holder. This survey could be conducted in cooperation with the annual raptor surveys conducted by other companies (coal and power) so that the companies may share costs.

- All APDs, Sundry Notices, and rights-of-way submitted for proposed wells and other surface-disturbing activities within Winkler cactus habitat shall be submitted before April 1 of any given year. This would allow the clearances for T & E plants at the optimum time. Any applications for surface-disturbing activities received after April 1 shall be held until the next year. On extremely dry years, the cactus does not surface or bloom and clearances shall be delayed until conditions are better, possibly until the next year.

- Avoid surface disturbance in special-status plant habitats. Site-specific evaluations or Section 7 Endangered Species Act consultation with the USFWS may allow for modifications to this requirement.

Livestock Management

- Any replacements , improvements, or additions of rangeland facilities shall meet BLM or Forest Service standards as applicable. [BLM Handbook H–1741–1 (fencing), BLM Manual Section 9100 (roads, reservoirs, dams, pipelines, cattle guards, gates, etc.), BLM Manual Section 9200 (Integrated and Chemical

Pest Management and Control), Forest Service Manual 2242.03, and BLM Price Field Office and Manti-La Sal National Forest policies.]

Recreation

- In the North Area, all existing recreational trails identified in the 1998 Carbon County Trails Plan that are disturbed by the Companies would be reclaimed to pre-development conditions upon abandonment of individual roads and locations. Reclamation of company-constructed roads throughout the Project Area would be determined by the Authorized Officer on a case-by-case basis in consultation with the County.

- The Companies and the BLM will complete an agreement to study the development of trails to offset recreational impacts in the Project Area.

Visual Resources

- Where topography permits, well sites would be positioned to prevent "sky lining".

- Existing vegetation and topographic features would be used to screen wells, facilities, and roads from the viewshed of Key Observation Points.

- To eliminate broadside views of pumping units, design well locations so the pumping units are situated "in line" with Key Observation Points.

- When installing chain link fences, use non-reflective materials to reduce visibility from a distance.

- Avoid straight line-of-sight bulldozing. Design roads through wooded areas shall to take a curvilinear path.

2.2.1 Primary Elements Comprising this Alternative

The primary elements comprising this alternative are very similar to those comprising Alternative 1 — Proposed Action. Also, the construction, operation, and decommissioning/reclamation phases would occur as described for Alternative 1. However, implementation of the environmental protection measures identified above would result in two primary differences from the facilities comprising Alternative 1. First, implementation of these measures would eliminate 14 wells from development in the South Area. To avoid conflicts with nests of raptors, Anadarko, Chandler, and Texaco would forgo development of four, eight, and four wells, respectively. Thus, the total number of new wells constructed under this alternative would be 335 (**Table 2–6**), instead of the 353 that would be developed under Alternative 1.

Second, the locations of many wells and roads proposed under Alternative 1 were moved for this alternative (**Plate 2–4**). These relocations were made in response to the environmental protection measure requiring avoidance of steep slopes (greater than 25 percent). As a result of these relocations, the overall total lengths of roads the Companies would construct would be slightly higher under this alternative, compared to Alternative 1 (**Table 2–6**).

The last element of Alternative 2 is an option for the use of electrical equipment instead of gas-fired compressors and pumps. Under Alternative 2, this option includes the installation of a network of underground and aboveground power lines. For analysis purposes, this network was estimated based on an

Table 2–6
Alternative 2 Ferron Natural Gas Project Facilities

Facility	Company: Anadarko	Chandler	Texaco	Total[1]
Number of Existing and New Wells				
Existing on				
Federal lands	7	5	18	30
State lands	8	4	6	18
Private lands	0	1	19	20
Total	15	10	43	68
Proposed on				
Federal lands	42	36	34	112
State lands	9	27	64	100
Private lands	10	12	33	55
Total	61	75	131	267
Total number of natural gas wells	76	85	174	335
Lengths of Roads (miles)				
Potentially upgraded[2] on				
Federal lands	24.4	11.4	11.4	47.2
State lands	5.0	14.6	14.6	34.1
Private lands	1.8	10.4	10.4	22.7
Total[1]	31.2	36.4	36.4	104.0
Proposed new on				
Federal lands	7.5	15.0	13.6	36.1
State lands	2.3	11.3	21.4	35.0
Private lands	2.5	3.3	6.7	12.5
Total	12.3	29.6	41.7	83.6
Total lengths of upgraded or new roads	43.5	66.0	78.1	187.6
Number of Disposal Wells	3	3	5	11
Compressors				
Existing Central Production Facilities[3]	1	1	2	4
Proposed Central Production Facilities[4]	1	3	3	7
Proposed Compressor Stations[4]	3	0	0	3
Total Horsepower	20,400	5,250	12,000	37,650

Notes:
1. Totals may not match precisely with values obtained by adding unit numbers due to rounding conventions.
2. Both Texaco and Chandler would use the upgraded roads in the South Area. Therefore, the total lengths of upgraded roads in the South Area were split evenly between Chandler and Texaco.
3. Chandler and Texaco would decommission their existing CPFs once the proposed CPFs are on line. However, they would continue to use the disposal wells associated with the existing CPFs.
4. One amine unit and one dehydration unit would be installed at each facility or station.

analysis of soil characteristics from the soil survey used in this EIS. Areas where the depth to bedrock is more than 18 inches and no cobbly rock soils were selected as locations where power lines could be buried. In areas where depth to bedrock is less than 18 inches and cobbly soil conditions are present, it was determined that the environmental effects of excessive blasting would outweigh any benefits of burying electric lines.

The aboveground power lines would be constructed using tracked and wheeled equipment. A crew with a backhoe or a line-boom truck with an auger attachment would dig the holes where accessible from the ROW for access roads. The holes would be located as to not disturb existing sensitive vegetation and would be excavated to a depth of 8 to 10 feet. Poles would be transported to the construction site by truck where the structural components would be assembled on the ground and erected by a boom truck. In areas where vegetation, topography, or the presence of sensitive resources inhibits the use of conventional power line construction, the BLM may require the use of helicopters to set structural components and string the conductor.

Pole locations could be moved within the 10-foot wide ROW if topography and/or impacts to cultural, vegetative, or wildlife resources are identified at the site of the structure. In areas of thick vegetation and/or where vegetation may impede the performance of the active line, vegetation would be cleared by hand-held chainsaws or any other equipment needed to complete the job. Where areas of sensitive plant resources are known to occur, the BLM would be consulted before removal of any vegetation.

When the structures are in place, the conductor would be strung. A sock line would be laid along the route by a light vehicle or by hand. Ground crews would place the sock line in pulleys on each structure at the insulator location. The conductor would then be pulled up by pulleys through the insulator with the assistance of a reel truck, or by hand, before moving to the next pole location. At least two miles of conductor could be pulled into place in a single setup.

Underground power lines would be buried along access roads. These power lines would be installed in a ditch excavated within the access roads' 40-foot ROW on the side opposite the gas and produced water gathering pipelines (**Figure 2–1**). The power lines would be installed using the same general construction techniques used to install the pipelines.

Under Alternative 2's electrical equipment option, 97 miles of power lines would be installed aboveground on 1,704 poles (30 feet tall) spaced at approximately 300-foot intervals and 73 miles would be buried. The distribution of the lines is shown on **Plate 2–5**. **Table 2–7** shows the linear extent of the aboveground power lines, the number of poles required for each classification of land ownership, and the distribution of buried lines on each land ownership classification.

2.2.2 Workforce and Construction Resource Requirements

The requirements for constructing the facilities comprising this alternative would be very similar to those identified for Alternative 1. However, due to the 18 fewer wells the Companies would install under this alternative, requirements for a workforce and requirements for construction materials would be slightly less. Most of the active workforce involved in developing the Proposed Action would be involved 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 the field. **Table 2–8** shows the estimated employment requirements for the construction, operation, and reclamation of the Ferron Natural Gas Project under Alternative 2.

Construction of Alternative 2 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. Equipment needed for construction would include heavy equipment (bulldozers, graders, track hoes, and front-end loaders) and heavy- and light-duty trucks.

Table 2–7
Summary of Above Ground and Buried Power Lines for Alternative 2

	Land Ownership			
Facility/Area	**BLM**	**State**	**Private**	**Total**
Aboveground Power Lines				
Miles of Power Lines				
North Area	6	3	2	11
South Area	23	47	16	86
Total	29	50	18	97
Number of Poles				
North Area	113	48	28	189
South Area	412	821	282	1,515
Total	525	869	310	1,704
Buried Power Lines				
Miles of Power Lines				
North Area	20	7	2	29
South Area	26	8	10	44
Total	46	15	12	73

Water would be needed for constructing roads, well pads, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct Alternative 2 is expected to be about 77 acre-feet (**Table 2–9**). This water would be purchased from local sources.

Sand and gravel would be required in the upgrading of at least parts of existing roads and the construction of new roads, well pads, and compressor facilities. Sand and gravel would be used to surface all newly-constructed roads in the collector and local classes to ensure a surface sufficient for year-round travel. The need for adding gravel to resource roads would be determined by the Authorized Officer or landowner on a case-by-case basis.

Table 2–10 summarizes the estimated amount of sand and gravel needed if surfacing is required on all new roads, roads potentially requiring upgrading, well pads, and compressor facilities. Approximately four inches of sand and gravel would be applied where needed on roads and well pads. The Companies would purchase sand and gravel from local commercial sources.

All other construction, operation, and decommissioning/reclamation activities identified for the Proposed Action would occur under this alternative. The production of water and gas would be essentially the same as described for the Proposed Action. Additionally, Questar would construct, operate, and maintain the transmission pipeline as described under the Proposed Action.

2.3 ALTERNATIVE 3 — NO ACTION ALTERNATIVE

The No Action Alternative is required by NEPA for comparison to other alternatives analyzed in the EIS. For this project, the No Action Alternative would not authorize additional natural gas development on

Table 2–8
Estimated Employment Requirements for Alternative 2

Work Category	Time Requirements	Number of Facilities	Personnel Required (# per day)	Workdays for Project	Workdays per Year	Average # of Workers per Day
Construction and Installation						
Access Road	4 days/mile	84 miles	4	1,344	269	1
Well Pad	2 days/site	267	8	4,272	854	4
Pipeline	10 days/mile	84 miles	10	8,400	1,680	7
Electrical Utility Lines[1]	5 days/mile	170 miles	4	3,400	680	3
Drilling and Casing	4 days/well	267	8	8,544	1,709	7
Well Completion	4 days/well	267	20	21,360	4,272	18
Well Production	10 days/well	267	16	42,720	8,544	36
Compressor facilities	90 days/site	10	20	18,000	3,600	15
New Disposal Wells	40 days/well	8	8	2,560	512	2
Total				110,600	22,120	92
Operation and Maintenance						
Road/Pad Maintenance	120 days/year	NA	3	7,200	360	2
Pumpers	260 days/year	NA	36	187,200	9,360	39
Office	260 days/year	NA	2	10,400	520	2
Well Workover	5 days/well	10/yr	2	2,000	100	0
Total				206,800	10,340	43
Reclamation and Abandonment						
Wells (gas and water)	3 days/well pad	344	4	4,128	NA	
Roads	4 days/mile	84	4	1,344	NA	
Compressor Dismantling	30 days/facility	14	20	8,400	NA	
Reclamation	5 days/facility	14	4	280	NA	
Total				14,152		

Note:
1. Applies to the electrical equipment option only.

Federal leases within the Project Area. Drilling could continue on State and private leases and access and pipelines across Federal lands to reach such proposed State and fee wells would be granted as required by BLM policy. The Environmental Protections Measures outlined in Alternative 2 would apply to rights-of-way granted for access to State and private leases.

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 leased 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 lease terms.

Table 2–9
Summary of Water Requirements for the Alternative 2

Item	Amount (size)	Rate	Total (acre-feet)
Roads and pipelines	84 miles	0.36 acre-feet/mile	30
Well pads	368 acres[1]	0.023 acre-feet/acre	8
Central production facilities	43.4 acres	0.29 acre-feet/acre	13
Compressor facilities	9.3 acres	0.29 acre-feet/acre	3
Drilling and completion			
Gas wells	267 wells	0.05 acre-feet/well	13
Disposal wells	8 wells	1.26 acre-feet/well	10
Total			77

Notes:
1. Areal extent based on 267 gas wells.
Source: Cox 1998.

On land leased without a No Surface Occupancy or similarly restrictive lease stipulation, the Department of Interior cannot deny a permit to drill. Once the land is leased, the Department no longer has the authority to preclude surface-disturbing activity, even if the environmental impact of such activity is significant. The Department can only impose mitigation measures upon a lessee who pursues surface-disturbing activities. By issuing a lease, the Department has made an irrevocable commitment to allow some surface disturbances (Tenth Circuit Court of Appeals in Sierra Club vs. Peterson [717 F. 2d 1409, 1983]).

Leases within the Project Area contain various stipulations concerning surface disturbance, surface occupancy, limited surface area, and timing restrictions. In addition, the lease stipulations provide for the imposition of such reasonable conditions, not inconsistent with the purposes for which the lease was issued, as the (BLM and/or Forest Service) may require to protect the surface of the leased lands and the environment. None of the stipulations, however, would empower the Secretary of Interior to deny all

Table 2–10
Summary of Sand and Gravel Requirements for Alternative 2

Facility	Amount	Unit	Application Rate (cubic yards per unit)	Total Volume (cubic yards)
New Roads	84	miles	1,430	120,120
Potentially-upgraded roads	104	miles	1,430	148,720
New well pads	267	pads	832	222,144
Central production facilities	7	facilities	3,225	22,575
Compressor, amine, and dehydration stations	3	stations	1,613	4,838
Total				518,397

Source: Cox 1998

development activity because of environmental concerns. Provisions in leases that expressly provide authority to deny or restrict development in whole or in part depend upon conformance with certain non-discretionary statutes, such as the Endangered Species Act (43 Code of Federal Regulations 3101.1–2).

2.3.1 Primary Elements Comprising this Alternative

The primary elements comprising this alternative are very similar to those comprising the other two alternatives. The Companies would construct gas wells, new roads, pipelines, and CPFs. Also, the construction, operation, and decommissioning/reclamation phases would occur as described for Alternative 1. However, the Companies would construct a smaller number of facilities under this alternative than they would under alternatives 1 or 2.

With implementation of this alternative, the Companies would construct fewer wells and a smaller infrastructure to support them (**Table 2–11**). The Companies would construct a total of 155 new natural gas wells, all of which would be on state and privately-owned lands (**Plate 2–6**). Fewer miles of existing roads would be upgraded and about 44 miles of new roads would be constructed. Finally, fewer CPFs would be required to handle the natural gas and produced water.

2.3.2 Water Production

Through 1997, the Companies have completed 53 wells in the South Area and would drill 136 more, an average of 27 wells per year, over the five-year construction time frame. Therefore, by the end of the construction period, the maximum average daily water production rate would be about 39,050 BWPD [(27 wells X 350 BWPD/well for the wells in the first year) + (27 X 300 for wells in the second year) + (27 X 250 for wells in the third year) + (27 X 200 for wells in the fourth year) + (27 X 150 for wells in the fifth year) + (53 X 100 for wells in the sixth and succeeding years). The projected disposal rate for Texaco's three proposed wells and Chandler's two wells is 8,500 BWPD, which would provide an overall capability of 42,500 BWPD. Texaco's existing disposal well would add a further 8,500 BWPD disposal capacity. Therefore, the proposed water disposal capacity of 51,000 BWPD would exceed the projected daily maximum water production rate (39,050 BWPD).

The Companies have completed 15 wells in the North Area during the past two years and would drill 19 more, an average of 4 wells per year, over the five-year construction time frame. Therefore, by the end of the construction period, the maximum average daily water production rate would be 6,250 BWPD [(4 wells X 350 BWPD/well for the wells in the first year) + (4 X 300 for wells in the second year) + (4 X 250 for wells in the third year) + (4 X 200 for wells in the fourth year) + (4 X 150 for wells in the fifth year) + (15 X 100 for wells in the sixth and succeeding years). The projected disposal rate for Anadarko's single existing well would be 10,000 BWPD. Therefore, the proposed water disposal capacity of 10,000 BWPD would exceed the projected daily maximum water production rate (6,250 BWPD) by 3,750 BWPD.

2.3.3 Workforce and Construction Resource Requirements

The requirements for constructing the facilities comprising this alternative would be smaller than those identified for alternative 1 or 2. Most of the active workforce involved in developing the project would be involved in construction-related activities. After roads and well pads are constructed, pipelines and utility

Table 2–11
Alternative 3 Ferron Natural Gas Project Facilities

	Company			
Facility	**Anadarko**	**Chandler**	**Texaco**	**Total[1]**
Number of Existing and New Wells				
Existing on				
Federal lands	7	5	18	30
State lands	8	4	6	18
Private lands	0	1	19	20
Total	15	10	43	68
Proposed on				
Federal lands	0	0	0	0
State lands	9	27	64	100
Private lands	10	12	33	55
Total	19	39	97	155
Total number of natural gas wells	34	49	140	223
Lengths of Roads (miles)				
Potentially upgraded[2] on				
Federal lands	11.2	7.3	7.3	25.8
State lands	2.4	14.2	14.2	30.9
Private lands	1.8	8.4	8.4	18.5
Total[1]	15.4	29.9	29.9	75.2
Proposed new on				
Federal lands	0.1	0.0	0.2	0.3
State lands	2.4	9.5	22.3	34.2
Private lands	1.8	2.5	5.4	9.7
Total	4.3	12.0	27.9	44.2
Total lengths of upgraded or new roads	19.7	41.9	57.8	119.4
Number of Disposal Wells	1	2	4	7
Compressors				
Existing Central Production Facilities	1	1	2	4
Proposed Central Production Facilities[3]	0	2	2	4
Proposed Compressor Stations	0	0	0	0
Total Horsepower	6,800	4,050	13,000	23,850

Notes:
1. Totals may not match precisely with values obtained by adding unit numbers due to rounding conventions.
2. Both Texaco and Chandler would use the upgraded roads in the South Area. Therefore, the total lengths of upgraded roads in the South Area were split evenly between Chandler and Texaco.
3. One amine unit and one dehydration unit would be installed at each facility.

lines are installed, and wells are drilled and completed, minimal personnel would be required to operate the field. **Table 2–12** shows the estimated employment requirements for the construction, operation, and reclamation of the Ferron Natural Gas Project under Alternative 3.

Construction of Alternative 3 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. Equipment

Table 2–12
Estimated Employment Requirements for Alternative 3

Work Category	Time Requirements	Number of Facilities	Personnel Required (# per day)	Workdays for Project	Workdays per Year	Average # of Workers per Day
Construction and Installation						
Access Road	4 days/mile	44 miles	4	704	141	1
Well Pad	2 days/site	155	8	2,480	496	2
Pipeline	10 days/mile	44 miles	10	4,400	880	4
Drilling and Casing	4 days/well	155	8	4,960	992	4
Well Completion	4 days/well	155	20	12,400	2,480	10
Well Production	10 days/well	155	16	24,800	4,960	21
Compressor facility	90 days/site	4	20	7,200	1,440	6
Disposal Well	40 days/well	5	8	1,600	320	1
Total				58,544	11,709	49
Operation and Maintenance						
Road/Pad Maintenance	120 days/year	NA	3	7,200	360	2
Pumpers	260 days/year	NA	36	187,200	9,360	39
Office	260 days/year	NA	2	10,400	520	2
Well Workover	5 days/well	10/yr	2	2,000	100	0
Total				206,800	10,340	43
Reclamation and Abandonment						
Wells (gas and water)	3 days/well pad	230	4	2,760	NA	
Roads	4 days/mile	44	4	704	NA	
Compressor Dismantling	30 days/facility	8	20	4,800	NA	
Reclamation	5 days/facility	8	4	160	NA	
Total				8,424		

needed for construction would include heavy equipment (bulldozers, graders, track hoes, and front-end loaders) and heavy- and light-duty trucks.

Water would be needed for constructing roads, well pads, and compressor stations. It also would be needed for drilling wells. Overall, the requirement for water to construct Alternative 3 is expected to be about 42 acre-feet (**Table 2–13**). This water would be purchased from local sources.

Sand and gravel would be required in the upgrading of at least parts of existing roads and the construction of new roads, well pads, and compressor facilities. Sand and gravel would be used to surface all newly-constructed roads in the collector and local classes to ensure a surface sufficient for year-round travel. The need for adding gravel to resource roads would be determined by the Authorized Officer or landowner on a case-by-case basis.

Table 2–14 summarizes the estimated amount of sand and gravel needed if surfacing is required on all new roads, roads potentially requiring upgrading, well pads, and compressor facilities. Approximately four inches

Table 2–13
Summary of Water Requirements for Alternative 3

Item	Amount (size)	Rate	Total (acre-feet)
Roads and pipelines	44 miles	0.36 acre-feet/mile	16
Well pads	214 acres[1]	0.023 acre-feet/acre	5
Central production facilities	24.8 acres	0.29 acre-feet/acre	7
Drilling and completion			
Gas wells	155 wells	0.05 acre-feet/well	8
Disposal wells	5 wells	1.26 acre-feet/well	6
Total			42

Notes:
1. Areal extent based on 155 gas wells.
Source: Cox 1998

of sand and gravel would be applied where needed on roads and well pads. The Companies would purchase sand and gravel from local commercial sources.

All other construction, operation, and decommissioning/reclamation activities identified for the Proposed Action would occur under this alternative. The production of water and gas would be essentially the same as described for the Proposed Action. Additionally, Questar would construct, operate, and maintain the transmission pipeline as described under the Proposed Action.

2.4 ALTERNATIVES CONSIDERED — BUT NOT EVALUATED IN DETAIL

Several additional project alternatives were considered as a result of issues raised during scoping. When they were considered, each potential alternative was evaluated and some were eliminated from detailed analysis in the EIS for various reasons. A description of these considered alternatives follows along with a brief description of the rationale for their exclusion.

Table 2–14
Summary of Sand and Gravel Requirements for Alternative 3

Facility	Amount	Unit	Application Rate (cubic yards per unit)	Total Volume (cubic yards)
New Roads	44	miles	1,430	62,920
Potentially-upgraded roads	75	miles	1,430	107,250
New well pads	155	pads	832	128,960
New central production facilities	4	facilities	3,225	12,900
Total				312,030

Source: Cox 1998

2.4.1 Alternative Well Densities

An alternative that incorporated the development of wells on an 80-acre well density pattern instead of the proposed 160-acre pattern was considered. The primary reason for its consideration was to ensure that the maximum well development scenario for the Ferron study area was evaluated in this EIS. It was dropped from consideration because the Companies have no current plans to pursue an 80-acre well density pattern because current geological information supports the proposed 160-acre development pattern. In addition, at Anadarko's request, the Utah Board of Oil Gas and Mining has issued a spacing order for portions of Anadarko's development in and around the North Area. This order is for a 160-acre well density pattern.

The geologic information and the spacing order do not preclude the development of an 80-acre pattern in the future if updated geologic data, economic conditions, or new technology would encourage this density. However, the development of an 80-acre pattern could not be permitted under this NEPA analysis. Additional environmental analysis under NEPA would be required to evaluate such a proposal at that time.

2.4.2 Proposed Action with Certain Areas Excluded from Development

This alternative was suggested so certain identified sensitive areas (such as wildlife security areas) would be eliminated from potential natural gas development. This alternative was dropped from further consideration in the EIS because it could prohibit development of valid leases. None of the leases acquired by the Companies have a lease-wide No Surface Occupancy stipulation. Therefore, this alternative could not be legally implemented.

2.4.3 Specific Buffers Around Residences

An alternative considering ½ and 1 mile buffer zones between well sites and residences was suggested during scoping to reduce potential impacts to local residents. It was not analyzed as a separate alternative in this EIS because buffer zones this size could preclude development on valid leases held by the Companies. Additionally, most leases near residences are located on non-Federal land and, therefore, are not within the jurisdiction of BLM.

2.4.4 Deeper Disposal Wells

An alternative was suggested that would require disposal wells to be developed into deeper formations than proposed. Analysis in Chapter 4 addressed impacts into the Navajo and four deeper formations. Therefore, a separate alternative was not necessary.

2.4.5 Alternate Produced Water Disposal Methods

Disposing water into the subsurface is the preferred method of produced water disposal by the UDOGM and BLM. All the disposal wells proposed for the Ferron Natural Gas Project would be located on State of Utah or private land and would be under the jurisdiction of UDOGM. BLM regulations in Onshore Oil and Gas Order No. 7 state that disposal of water from Federal leases into permitted injection wells on State or private lands would be approved by BLM.

Several different methods of produced water disposal were considered and have been investigated for the proposed project. The methods were evaluated on the basis of economics, applicability and reliability.

Disposal of produced water in surface impoundments was suggested as an alternative to subsurface disposal. This method is dependent on evaporation rates and results in inconsistent year-round disposal capability. Other issues arise with the eventual disposal of salt concentrations and residuals, and pit abandonment and subsequent reclamation. Due to the large volumes of water that could be expected from the Proposed Action, numerous surface disposal pits would be necessary. Even with several surface pits, it is anticipated that other forms of disposal would be necessary to accommodate water volumes. Evaporation ponds were not considered as a long-term option for disposal.

An alternative was also considered for using produced water for beneficial uses such as to control fugitive dust on roads and disturbed areas, for livestock water, or other uses. This was suggested in order to eliminate the need for water disposal while possibly providing a local benefit. Produced water would have to be treated before it would be suitable for other uses because it contains high level of suspended coal fines, total dissolved solids, calcium, magnesium, sodium, potassium, chloride, sulfate, and bicarbonate (see **Section 3.2.2.2**). Five alternative technologies for the treatment of produced water were evaluated to provide a comparison with the current practice of deep injection. They included distillation, freeze desalination, reverse osmosis, electro-dialysis, and ion exchange.

Distillation can be conducted through different processes (long-tube-vertical multiple effect distillation, multi-stage flash-evaporation, and forced-circulation vapor compression processes). All these processes treat water by evaporating it and then condensing the resultant vapor in a manner to recover and reuse as much of its heat content as possible. Distillation yields a relatively pure water stream, but evaporation has a large energy requirement (Cox and Stevens 1993). Costs are among the highest of the treatment technologies (Cox and Stevens 1993).

Freeze desalination involves freezing saline water to form a slurry of ice crystals and brine, from which the ice crystals are separated, rinsed, and melted. This process has not been applied in commercial projects and needs more research and development before it becomes acceptable (Cox and Stevens 1993). In addition, no cost estimates were found.

Reverse osmosis is the most widely applied desalination process for municipal and industrial plants in the U.S. and has been used in several petroleum industry settings (Cox and Stevens 1993). Reverse osmosis is a membrane process where water under pressure passes through a semi-permeable membrane but the contaminants do not. By repeating this cycle several times, a concentrated waste stream and a relatively pure water stream are obtained. The process is greatly degraded by the presence of fine suspended solids (coal fines) (Office of Technology Assessment [OTA] 1980) that are present in produced water from coal beds in the area. Costs for this process in the San Juan Basin were estimated to range from $0.30 to $0.70 per barrel of produced water (Cox and Stevens 1993).

Reverse osmosis has recently been tested as a water disposal method in the Castlegate Field, an abandoned coal bed methane project northwest of Price, Utah. This project was developed to produce gas from the coal beds of the Blackhawk Formation with produced water disposed into formations above the Blackhawk. Reverse osmosis was investigated as a disposal option primarily due to problems encountered with subsurface disposal of produced water. While treatment was successful, long term expenses were considered uneconomical compared to subsurface disposal for the high volumes of produced water encountered, and the field was eventually abandoned.

Electro-dialysis is similar to reverse osmosis in that semi-permeable membranes are used. However, in electro-dialysis the ions are forced across the membranes by an electrical potential. Electro-dialysis has not been used in petroleum applications, but has been used in such a wide variety of applications that only minor changes are likely to be needed to adapt it to CBM operations (Cox and Stevens 1993). Removal rates for electro-dialysis were reported as 10 to 40 percent in 1980 (OTA 1980) and as 80 to 85 percent in 1993 (Cox and Stevens 1993). Costs for electro-dialysis are estimated around $0.30 per barrel (Cox and Stevens 1993).

Ion-exchange removes dissolved solids from water by exchanging waterborne ions for other, more soluble ions as the water passes through chemical "resins" (Cox and Stevens 1993). Ionexchangers are useful for removing hardness (calcium and magnesium ions), but are inefficient for removing carbonate, bicarbonate, or chloride ions (Cox and Stevens 1993). Ion-exchange is not effective on highly saline waters. This process is also ineffective in removing organic compounds and suspended particulates (OTA 1980). Ion exchangers typically have limited capacity and therefore do not serve as the primary removal process (OTA 1980).

Table 2–15 presents a relative comparison of the technologies in removing dissolved solids (OTA 1980). Adaptability in the table refers to the ability to respond to changing water quality. For comparison purposes, subsurface disposal was also included in the table.

Table 2–15
Relative Ranking of Treatment/Disposal Technologies for Dissolved Solids

	Parameter			
Technology	**Removal Rate (percent)**	**Reliability**	**Adaptability**	**Relative Cost**
Distillation	99	Medium	Low	Very high
Reverse osmosis	60–95	Medium	Medium	Medium
Electro-dialysis	10–85	Medium	Medium	Very high
Ion-exchange	High	High	Low	High
Sub-surface disposal	High	High	High	Low

Source: Cox and Stevens 1993 and OTA 1980.

Treatment of produced water is not analyzed in this EIS. Water treatment options have not been tested to determine if they would be viable for use in the project area. Most of the options would also be uneconomical. Reverse osmosis to treat produced water could be possible, but the high volumes of water and the presence of suspended coal fines negate this treatment method as a feasible option. Produced water would be a waste product of the proposed gas production. Treatment of produced water is not a regulatory requirement. While there is a possibility for making water available for treatment, to date, no proposals have been submitted to treat waste water from existing projects in the area. Any proposal to treat produced water from Federal leases would undergo separate NEPA analysis.

2.4.6 Directional Drilling

Directional drilling can only be considered a viable alternative if the method meets the proponent's needs. To date, none of the Companies has proposed any directional wells. Several technical and economic aspects challenge the feasibility of directional drilling.

First, CBM wells are produced by pumping water from the coal seams to the surface; a process known as "dewatering." The water is brought to the surface using pumping units and rod actuated subsurface pumps. Wells must be nearly vertical to accommodate this production equipment. Therefore, the deviation from vertical in the wellbore must be very gentle. In the Project Area, not enough vertical distance exists, from the surface to the target formation, to drill a directional well that would access an adjacent spacing unit while still being able to accommodate a pump.

Secondly, coal exists locally in multiple seams; therefore, in order to access all of the coal, at least one lateral leg would have to be drilled into each coal seam. The technology of conventional horizontal drilling does not permit this many laterals in such a limited vertical section. Multiple laterals can be drilled using ultra-short radius horizontal drilling, but technology does not exist to drill the laterals far enough away from the wellbore to influence an adjacent spacing unit.

In addition to the above technical impediments, directional and horizontal wells are much more expensive to drill. They require larger rigs, larger drill pas, larger reserve pits, they take much longer to drill, must be drilled with mud rather than air, and they require specialized tools, surveys and expertise.

2.4.7 Staged Development

This suggested alternative involves two separate concepts. The first considers phasing the development of a lease to allow only enough sites to be developed to hold the lease. Further development of that lease would be precluded until production of these wells has reached its economic end. This was not analyzed in the EIS because timely development of leases would be restricted and it would be technically infeasible because dewatering of the coal seam is only effective with a large number of wells working concurrently. The second concept involves phased development in an area wide context. That is, a certain number of wells would be developed in one area and operated until production ends before proceeding to another area. This was eliminated because it would restrict timely development of leases and could violate valid lease rights.

2.4.8 Alternative Transmission Pipeline Routes

Alternative routes for Questar's proposed transmission pipeline were initially considered. However, they were readily discounted as viable alternatives because they would not follow an existing pipeline and right-of-way like Questar's proposed route does. Therefore, alternative routes would require more disturbance of previously undisturbed land than would occur under the proposed route.

2.5 SUMMARY ALTERNATIVES AND IMPACTS

The following tables summarize the alternatives considered in detail and the likely environmental consequences of each alternative. **Table 2–16** contains the summary of alternatives. This table contrasts the three alternatives in terms of their physical characteristics.

The matrix presented in **Table 2–17** provides a comparative summary of the impacts to the various environmental resources that would be realized by implementing each of the three alternatives for the Ferron Natural Gas Project.

Table 2–16
Comparison of Alternatives Considered in Detail

Parameter	Alternative 1	Alternative 2	Alternative 3
Facilities			
Number of Natural Gas Wells			
Existing on			
Federal lands	30	30	30
State lands	18	18	18
Private lands	20	20	20
Total	68	68	68
Proposed new on			
Federal lands	130	112	0
State lands	100	100	100
Private lands	55	55	55
Total	285	267	155
Total number of wells	353	335	223
Roads (miles)			
Potentially upgraded on			
Federal lands	47	47	26
State lands	34	34	31
Private lands	23	23	18
Total	104	104	75
Proposed new on			
Federal lands	48	36	<1
State lands	36	35	34
Private lands	14	13	10
Total	98	84	44
Total for all roads	202	188	119
Number of proposed water disposal wells	11	11	7
Proposed Compressors			
Number of existing CPFs	4	4	4
Number of proposed CPFs	7	7	4
Number of proposed compressor stations	3	3	0
Total horsepower	37,650	37,650	23,850

Table 2–16 (continued)
Comparison of Alternatives Considered in Detail

Parameter	Alternative 1	Alternative 2	Alternative 3
Short-term Disturbance (acres)			
Proposed Wells on			
Federal lands	179	154	0
State lands	138	138	138
Private lands	76	76	76
Total	393	368	214
Proposed Roads on			
Federal lands	458	341	3
State lands	339	331	323
Private lands	129	118	91
Total	926	790	418
Proposed CPFs	43	43	25
Proposed Compressor Stations	9	9	0
Total for all facilities	1,371	1,210	657
Long-term Disturbance (acres)			
Proposed Wells on			
Federal lands	107	93	0
State lands	83	83	83
Private lands	45	45	45
Total	236	221	128
Proposed Roads on			
Federal lands	235	175	2
State lands	174	170	166
Private lands	66	61	47
Total	475	405	214
Proposed CPFs	43	43	25
Proposed Compressor Stations	9	9	0
Total for all facilities	763	678	367
Workforce Requirements			
Construction and Installation (number of workdays for the project)	117,768	110,600	58,544
Operation and Maintenance (number of workdays for the project)	206,800	206,800	206,800
Reclamation and Abandonment (number of workdays for the project)	14,616	14,152	8,424
Water Requirements (acre-feet)	84	77	42
Sand and Gravel Requirements (cubic yards)	553,393	518,397	312,030

Table 2–17
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
GEOLOGY AND MINERALS			
Removal of natural gas resources	680 bcf Project total	645 bcf Project total	430 bcf Project total
Conflict with exiting coal leases or KCRA	No conflict with active coal leases; one potential conflict with KCRA on State land.	No conflict with active coal leases; one potential conflict with KCRA on State land.	No conflict with active coal leases; no conflict with KCRA.
WATER RESOURCES			
Effects to groundwater	Disposal of produced water would transfer saline groundwater from the Ferron Sandstone to the Navajo Aquifer. Shallow alluvial aquifers could be affected by spills and construction activities. Blasting near springs and water wells could affect flows.	Similar to Alternative 1. Produced water would be transferred from the Ferron Sandstone to the Navajo Aquifer. Environmental protection measures would limit construction near streams and in floodplains to reduce effects on shallow aquifers. Protection measures for avoidance of construction and blasting near springs would protect springs and seeps and reduce impacts.	Same effects as the Proposed Action, but at a proportionally lower rate as 130 fewer wells would be drilled.
Effects to surface water	Increased sedimentation and salinity due to surface disturbances. Sedimentation and salinity would be more pronounced from construction near water courses and from pipelines and roads that cross streams and ephemeral drainages. Sediment delivery would be 4.5 tons/acre/yr. Salinity delivery would be 0.319 tons/acre/yr. These rates would occur on 763 acres of long-term disturbance. Increased risk of spills of chemicals, drilling fluids, fuels and produced water from wells and facilities near streams and drainage.	Similar impact to Alternative 1, but protection measures would safeguard springs and reduce spill impacts. Sediment delivery would be reduced to 4.0 tons/acre/yr. Salinity delivery would be 0.239 tons/acre/yr. These rates would occur on 678 acres of long-term disturbance.	Same effects as the proposed action but at a proportionally lower rate. Sediment delivery would be 4.4 tons/acre/year. Salinity delivery would be 0.306 tons/ acre/yr. These rates would occur on 367 acres of long-term disturbance. Increased risk of spills of chemicals, drilling fluids, fuels and produced water from wells and facilities near streams and drainage.
AIR QUALITY			
Construction dust effects	Construction dust would be controlled per Utah Air Conservation Rules by watering, chemical application, wind breaks, vegetative or synthetic covering. Companies are not proposing dust control on roads during operations. Dust levels from operational vehicles may be locally high.	Construction dust would be controlled per Utah Air Conservation Rules by watering, chemical application, wind breaks, vegetative or synthetic covering. BLM would require dust suppression techniques to be applied on roads near residences and high traffic volume.	Construction dust would be controlled per Utah Air Conservation Rules by watering, chemical application, wind breaks, vegetative or synthetic covering. Dust levels from operational vehicles may be locally high if dust suppression is not applied to roads near residences and high traffic volume.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
Operational compressor effects	Ambient air levels of NO_2 would be moderate on elevated terrain within one mile of compressors. Maximum levels would be below NAAQS in all cases. Maximum levels of NO_2 would exceed Class II PSD increment near compressors at elevated terrain nearby. No other standards would be exceeded. If recommended mitigation are implemented, no NO_2 Class II incremental increase would be exceeded. With the electric power option, no NO_x or CO emissions would occur.	Ambient air levels of NO_2 would be moderate on elevated terrain within one mile of compressors. Maximum levels would be below NAAQS in all cases. Maximum levels of NO_2 would exceed Class II PSD increment near compressors at elevated terrain nearby. No other standards would be exceeded. If recommended mitigation are implemented, no NO_2 Class II incremental increase would be exceeded. With the electric power option, no NO_x or CO emissions would occur.	Ambient air levels of NO_2 would be moderate on elevated terrain within one mile of compressors. Ambient air levels of NO_2 may exceed PSD Class II increment if compressors are constructed near elevated terrain.
Effects to regional haze.	Regional visibility may be reduced by 10 percent 4 days per year at Capitol Reef National Park. If recommended mitigation measures are implemented, visibility at Capitol Reef would not be reduced by more than 10 percent on any days. With the electric power option, the Proposed Action would not affect regional visibility.	Regional visibility may be reduced by 10 percent 4 days per year at Capitol Reef National Park. If recommended mitigation measures are implemented, visibility at Capitol Reef would not be reduced by more than 10 percent on any days. With the electric power option, this alternative would not affect regional visibility.	Regional visibility would not be reduced by more than 10 percent at any of the nearby National Parks.
SOILS			
Erosional effects from facilities located on critical soils with slopes greater than 6 percent	178 wells and portions of the access roads would be on critical soils with slopes in excess of 6 percent. Water and wind erosion would increase, especially with disturbances on critical soils. Soil loss from 763 acres of long-term disturbances would be 11.2 tons/acre/year.	Environmental protection measures would reduce impacts to soils by avoiding critical soils on slopes where possible. 160 wells and portions of the access roads would be on critical soils with slopes greater than 6 percent. Water and wind erosion would increase. Increased soil loss from 678 acres of long-term disturbance would be 9.9 tons/acre/year. Overall soil loss is projected to be about 88 percent of loss associated with the Proposed Action.	Effects similar to Alternative 1, but proportionally less. 39 wells would be constructed on critical soils with slopes in excess of 6 percent. Soil loss increase from 367 acres of long-term disturbance would be 6.6 tons/acre/year. Overall soil loss would be 59 percent less than the Proposed Action.
Facility location of slopes greater than 25 percent	44 wells and portions of their access roads would be located on slopes greater than 25 percent. Water and wind erosion would increase and reclamation success would be difficult on these well pads and roads.	No wells or roads would be located on slopes greater than 25 percent. Wells and access roads would be relocated to exclude construction on slopes greater than 25 percent.	Effects similar to Alternative 1, but proportionately less. No roads would be constructed on slopes greater than 25 percent on BLM lands.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
Effects on soil properties	Soil compaction, loss of soil productivity and soil profile and a breakdown in soil structure from facility and road construction, and surface disturbances.	Same as Proposed Action, but slightly less, as 18 fewer wells would be drilled.	Same as the Proposed Action but, proportionally less because 155 new wells would be drilled instead of 285.
VEGETATION			
Loss of vegetation	1,633 acres of vegetation (1.5 percent of the Project Area) would be removed for construction. After partial reclamation, long-term vegetation loss would be 763 acres (0.7 percent of the project Area). 46 percent of disturbance would be on BLM land. 97 percent of vegetation would be pinyon-juniper, sagebrush/grassland, and salt desert shrub.	1,472 acres of vegetation (1.3 percent of the Project Area) would be removed for construction. After partial reclamation, long-term vegetation loss would be 679 acres (0.6 percent of the project Area). 41 percent of disturbance would be on BLM land. 98 percent of vegetation would be pinyon-juniper, sagebrush/grassland, and salt desert shrub.	916 acres of vegetation (0.8 percent of the Project Area) would be removed for construction. All vegetation removal would be on State and private land. After partial reclamation, long-term vegetation loss would be 367 acres (0.3 percent of the project Area). 96 percent of vegetation would be pinyon-juniper, sagebrush/ grassland, and salt desert shrub.
Invasion of noxious weeds	Disturbance would increase potential for spread of noxious weeds. Implementation of the Weed/ Vegetation Management Plan would reduce potential for establishment of noxious weeds.	Disturbance would increase potential for spread of noxious weeds. Implementation of the Weed/Vegetation Management Plan would reduce potential for establishment of noxious weeds.	Disturbance would marginally increase potential for spread of noxious weeds. Noxious weeds would be controlled by Companies in accordance with State and County laws.
RIPARIAN AREAS			
Riparian communities loss	Construction would remove 10.3 acres of riparian communities in South Area. One-half would be on BLM land. Effects would be long-term after the project ends because of the long time required for regrowth of riparian overstory.	Construction would remove 9.3 acres of riparian communities in South Area. About 18 percent would be on BLM land. Effects would be long-term after the project ends because of the long time required for regrowth of riparian overstory.	Construction would remove 6.9 acres of riparian communities in South Area. Almost all would be on private land. Effects would be long-term after the project ends because of the long time required for regrowth of riparian overstory.
WILDLIFE			
Effects on aquatic species	12 wells would be located in floodplains adjacent to perennial streams. Increased sedimentation could occur during heavy precipitation.	Because of other environmental restraints, 6 wells would not be constructed adjacent to perennial streams. Sedimentation potential would be reduced by 50 percent.	Potential impacts would be similar to other alternatives because State and private lands contain most of the wells that would be constructed along perennial streams.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
Effects on mule deer winter range	65 new wells would be constructed in North Area. Development would directly disturb 229 acres (1.2 percent of North Area winter range). Indirect disturbance to habitat would affect 4,235 acres (22.9 percent of winter range within the North Area) within 200 meters of facilities during operations. Deer normally using winter range may vacate these areas of indirect disturbance. 177 new wells in South Area would be constructed on winter range. Development would directly disturb 890 acres (1.5 percent of South Area winter range). Indirect disturbance to habitat would affect 13,505 acres (24 percent of winter range within the South Area) within 200 meters of facilities during operations. Deer normally using winter range may vacate these areas of indirect disturbance.	No construction would occur when animals are using winter range. 61 new wells in North Area would be constructed on winter range. Development would directly disturb 201 acres. Indirect disturbance to habitat would affect 3,534 acres within 200 meters of facilities during operations. 163 new wells in South Area would be constructed on winter range. Development would directly disturb 740 acres (1.3 percent of South Area winter range). Indirect disturbance to habitat would affect 11,082 acres (19 percent of winter range within the South Area) within 200 meters of facilities during operations. Deer normally using winter range may vacate these areas of indirect disturbance. Mitigation would involve direct payments for loss of winter range to enhance adjacent winter range habitat.	19 new wells on private and State land would be constructed in North Area on winter range. Development would directly disturb 67 acres (0.4 percent of North Area winter range). Indirect disturbance to habitat would affect 521 acres (2.8 percent of winter range within the North Area) within 200 meters of facilities during operations. Deer normally using winter range may vacate these areas of indirect disturbance. 105 new wells on State and private land in South Area would be constructed on winter range. Development would directly disturb 428 acres (0.7 percent of South Area winter range). Indirect disturbance to habitat would affect 6,844 acres (12 percent of winter range within the South Area) within 200 meters of facilities during operations. Deer normally using winter range may vacate these areas of indirect disturbance.
Effects on elk winter range	No elk winter range occurs in the North Area. 50 wells would be constructed in winter range in the South Area directly disturbing 207 acres (0.8 percent of the winter range). Construction would occur when animals are using winter range and would drive animals away from construction during winter range times. Indirect disturbance to habitat would affect 11,969 acres (49 percent of winter range within the South Area) within 800 meters of facilities during operations. Elk normally using winter range may vacate these areas of indirect disturbance.	No construction would be allowed during time elk use winter range. 49 wells would be constructed within winter range directly disturbing 128 acres 0.5 percent of winter range within the South Area). Indirect disturbance would affect 11,011 acres (45 percent of winter range within the South Area) within 800 meters of facilities during operations. Elk normally using winter range may vacate these areas of indirect disturbance. Mitigation would involve direct payments by Companies for loss of winter range to enhance adjacent winter range habitat.	46 wells would be constructed within winter range directly disturbing 179 acres (0.7 percent of winter range within the South Area). Indirect disturbance would affect 10,096 acres (41 percent of winter range within the South Area) within 800 meters of facilities during operations. Elk normally using winter range may vacate these areas of indirect disturbance.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
Effects on raptors	No construction would occur within ½ mile of raptor nests during the breeding season, February 1 through August 15. Construction during breeding season would not occur within ½ mile of 140 known and active nests. This restriction would affect 59 proposed wells. Operational activities within ½ mile of active nests could lead to nest abandonment, increased disturbance from Companies and public using roads, and temporary reduction in prey populations. With the electric power option, additional disturbance would be minor and the power lines would be constructed according to the APLIC's guidelines, so the potential for electrocuting raptors would be minimized.	Same as Alternative 1 for timing restrictions. Environmental protection measure would preclude permanent surface occupancy within ½ mile of an active raptor nest precluding the construction of 12 wells in the South Area. With the electric power option, additional disturbance would be minor and the power lines would be constructed according to the APLIC's guidelines, so the potential for electrocuting raptors would be minimized.	No seasonal or construction restrictions within ½ mile of raptor nests. 22 wells could be constructed within ½ mile of known raptor nest.
SPECIAL STATUS SPECIES			
Effects to Special-status species	5 wells and 1,800 feet of access roads would be constructed in or near Winkler cactus populations. 6 wells and 6,120 feet of access road would be constructed in or near known populations of Creutzfeldt-flower. Pre-construction surveys would identify exact location and facilities would be re-located to avoid these species. 12 wells and access roads are proposed for construction within the one-mile buffer around peregrine falcon aerie. Impact should be minimal because of widespread hunting habitat on adjacent Forest Service lands. With the electric power option, disturbance associated with construction of the power lines would be minor because the power lines could be moved to avoid known populations. Power lines would be constructed according to the APLIC's guidelines, so the potential for electrocuting special-status raptors would be minimized.	Same as Alternative 1 except one-mile buffer would be imposed around peregrine falcon aerie. 8 fewer wells and access roads would be constructed on federal lands because of the no surface occupancy within one mile of a peregrine falcon aerie. With the electric power option, disturbance associated with construction of the power lines would be minor because the power lines could be moved to avoid known populations. Power lines would be constructed according to the APLIC's guidelines, so the potential for electrocuting special-status raptors would be minimized.	Four wells would be constructed on State lands within the one-mile of a peregrine falcon aerie buffer. Populations of special status plants, if present, may be uprooted by development.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
CULTURAL RESOURCES			
Effects to Cultural resources	Construction activities could affect 77 sites in addition to the 10 known significant sources in the Project Area. Some of these sites could be destroyed before they are discovered. Four sites eligible for the NRHP could be inadvertently destroyed. If found, construction would cease, authorities would be notified, and mitigation of site would be carried out according to the Ferron Natural Gas Project Cultural Resource Treatment Plan. Pre-construction surveys would allow the opportunity to find and evaluate previously unknown cultural resources. With the electric power option, an additional six sites could be affected directly or indirectly. Also, one additional site may be affected by inadvertent destruction.	Construction activities could affect 69 sites in addition to the 10 known significant sources in the Project Area. Some of these sites could be destroyed before they are discovered. Four sites eligible for the NRHP could be inadvertently destroyed. If found, construction would cease, authorities would be notified, and mitigation of site would be carried out according to the Ferron Natural Gas Project Cultural Resource Treatment Plan. Pre-construction surveys would allow the opportunity to find and evaluate previously unknown cultural resources. With the electric power option, an additional six sites could be affected directly or indirectly. Also, one additional site may be affected by inadvertent destruction.	Construction activities could affect 40 sites in addition to the 10 known significant sources in the Project Area. Some of these sites could be destroyed before they are discovered. Two sites eligible for the NRHP could be inadvertently destroyed. If found, construction would cease, authorities would be notified, and mitigation of site would be carried out according to the Ferron Natural Gas Project Cultural Resource Treatment Plan. Pre-construction surveys would allow the opportunity to find and evaluate previously unknown cultural resources. With the electric power option, an additional six sites could be affected directly or indirectly. Also, one additional site may be affected by inadvertent destruction.
LAND USE			
Effects to land use	Total long-term disturbance would be 763 acres, or 0.7 percent of the Project Area. About 50 percent of disturbance would be on BLM land. Most of disturbance would be on rangeland. 53 wells would be constructed within one mile of residences. Dust levels and noise at these residences would be temporarily elevated during construction activities at these residences.	Total long-term disturbance would be 678 acres, or 0.6 percent of the Project Area. 41 percent of disturbance would be on BLM land. Most of disturbance would be on rangeland. 53 wells would be constructed within one mile of residences. Dust levels and noise at these residences would be temporarily elevated during construction activities at these residences.	All wells and most access roads would be constructed on State and private lands. 26 wells would be constructed within one mile of residences. Dust levels and noise at these residences would be temporarily elevated during construction activities at these residences.
Effects to transportation	Construction related traffic would average 110 trips per day, an increase of 1 to 5 percent over present levels, from Price area to Project Area. Operational traffic would average less than one percent of present levels. Slight increase of traffic accident potential (2 to 5 percent) during construction activities where project traffic would enter paved highways.	18 fewer wells would be drilled. Effects would be similar, but slightly less, to Alternative 1.	Construction traffic would be similar to the Proposed Action for the three years required for construction. Operational traffic would be considerably less than the Proposed Action because only 82 wells would be operated.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
LIVESTOCK MANAGEMENT			
Effects to livestock management	During construction, grazing would be reduced by almost 70 AUMs, (49 AUMs BLM) a decrease of less than 1 percent. Grazing would be reduced by 46 AUMs (33 AUMs BLM) during the operational phase. Increased traffic and access may lead to harassment and minor loss of livestock.	Effects on grazing would be similar to the Proposed Action. Environmental protection measure dictates range improvements must meet BLM standards and reduce the potential for traffic-related conflicts. Increased traffic and access may lead to harassment and minor loss of livestock.	Grazing on State and privately-owned land would be reduced by about 13 AUMs.
RECREATION			
Effects to recreation opportunities	Construction activities would alter the recreational experience for users 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 still affect the natural setting of the Project Area for the life of the project. BLM recreation management objectives would not be met in Semi-primitive Motorized areas.	Construction activities would alter the recreational experience for users 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 still affect the natural setting of the Project Area for the life of the project. BLM recreation management objectives would not be met in Semi-primitive Motorized areas.	No impacts to recreation on BLM lands would occur. Loss of solitude and natural setting could occur on State lands.
VISUAL RESOURCES			
Effects to visual resources	114 wells, associated access roads, and 5 CPFs would be constructed on VRM Class III areas and the Class III management objectives may not be met. With the electric power option, about 187 miles of aboveground power lines and 1,532 power poles would be constructed in VRM Class III areas and may not meet management objectives.	114 wells, associated access roads, and 5 CPFs would be constructed on VRM Class III areas and the Class III management objectives may not be met. With the electric power option, about 32 miles of aboveground power lines and 552 power poles would be constructed in VRM Class III areas and may not meet management objectives.	BLM Class II and III objectives designated for non-federal lands may not be met on State and private lands.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
NOISE			
Noise effects	Construction noise would be above 55 dBA within 1,500 feet of activities. 5 residences would experience noise above 55 dBA from construction on BLM land. 14 residences would experience noise above 55 dBA from construction on private land. Noise from drilling would be above 55 dBA at distances out to 2,000 feet. Noise would be short-term (1 to 4 days) but would occur 24 hours per day at the 14 residences. Operational noise from pumping units would be below 55 dBA at distances beyond 200 feet from these units. Therefore, after construction activities, noise levels would not be significant.	Noise effects would be similar to the Proposed Action. The location of the 18 fewer wells would be far away from residences.	Noise levels would be above 55 dBA for the 14 residences within 2,000 feet of wells constructed on State and private land.
SOCIOECONOMICS			
Effects to employment	98 people would be employed for construction activities. 40 percent would be locally hired and 60 percent would be specialists from outside the area. Employment would be seasonal during the 8-month construction period. Construction period would be 5 years. Secondary activities (services, supply) would create about 25 jobs annually during construction phase. 43 people would be permanently employed during the operational phase of the Project.	With 18 fewer wells, 94 people would be employed for construction activities. 40 percent would be locally hired and 60 percent would be specialists from outside the area. Employment would be seasonal during the 8-month construction period. Construction period would be 5 years. Secondary activities (services, supply) would create about 25 jobs annually during construction phase. 43 people would be permanently employed during the operational phase of the Project.	Since 155 new wells would be constructed, employment level would occur only for three years.
Effects to wages	Combined annual payroll of the three Companies would average about $900,000 during initial construction phase. This amount would be less than one percent of Carbon and Emery counties. The combined payroll during the operational phase would average about $1,150,000.	Combined annual payroll of the three Companies would average about $867,000 during initial construction phase. This amount would be less than one percent of Carbon and Emery counties. The combined payroll during the operational phase would average about $999,000.	Combined annual payroll would be reduced to $621,000 because a maximum of 155 wells would be constructed.
Effects on housing and community services	Small influx of transient employees (59 people) would not have significant effect. Workers would tend to live in spread out communities in and near the Project Area.	Influx of transient employees (56 people) would not have significant effect. Workers would tend to live in spread out communities in and near the Project Area.	Small flux of transient employees would only occur for the three-year construction period.

Table 2–17 (continued)
Ferron Natural Gas EIS Summary of Impacts

Type of Potential Impact	Alternative 1 — Proposed Action	Alternative 2 — Proposed Action with Environmental Protection Measures	Alternative 3 — No Action
Royalties generated	Federal royalties would be $53 million over life of project. $27 million would be paid to State of Utah of which $6.8 million would be distributed directly to Carbon and Emery Counties. With the electric power option, employment would increase an additional three percent.	Federal royalties would be $50 million over life of project. $23 million would be paid to State of Utah of which $6.6 million would be distributed to Carbon and Emery Counties. With the electric power option, employment would increase an additional three percent.	There would be no federal royalties. Therefore, none would be distributed to Carbon and Emery counties. All wells would be constructed on State and private land.
HEALTH AND SAFETY			
Risk associated with construction and operations	Risks to employees, subcontractors and public would be similar to those associated with heavy construction and industry.	Risks wold be similar to Proposed Action but slightly less because 18 fewer wells would be constructed and operated.	Risks less than Proposed Action because only 154 wells would be constructed and operated.
RECLAMATION			
Reclamation potential	1,633 acres disturbed. 77 percent of disturbance would involve soils unsuitable for reclamation. Reclamation in these areas would require multiple growing seasons and reseeding to generate vegetative cover similar to cover that currently exists.	1,473 acres disturbed. About 75 percent of disturbance would involve soils unsuitable for reclamation. Reclamation in these areas would require multiple growing seasons and reseeding to generate vegetative cover similar to cover that currently exists.	917 acres disturbed on State and private lands. 68 percent of disturbance would involve soils unsuitable for reclamation. Reclamation in these areas would require multiple growing seasons and reseeding to generate vegetative cover similar to cover that currently exists.