2.0 PROPOSED ACTION AND ALTERNATIVES

2.1 PROPOSED ACTION

The Proposed Action is an approval of QEP's proposal. QEP proposes to fully develop hydrocarbon resources underlying oil and gas mineral leases owned at least in part by QEP within the (GDBR) located in Townships 7 and 8 South, Ranges 21 to 24 East, Salt Lake City Base Meridian (Figure 2-1). These mineral leases were issued by the United States Government and the State of Utah. The leases grant certain rights to explore, develop, and produce the oil and gas resources underlying such leases, grant certain rights for reasonable ingress and egress to develop such leases, and retain in the lessor a royalty interest on production.

Development of the oil and gas resources has been occurring within the GDBR and adjacent areas since 1950. As of March 1, 2003 the GDBR included approximately 278 existing oil and water-injection wells producing from or injecting water into the Green River Formation and 300 gas wells producing from the Wasatch Formation. QEP has established Standard Operating Procedures (SOP) for construction, drilling, completion, and operational activities. An example of these SOPs, or how QEP does business with BLM oversight in the GDBR, is shown in Appendix 2-1.

Approximately 57 miles of primary roads and 314 miles of secondary roads have been constructed within the GDBR. Ownership of some of these roads has been asserted by Uintah County under the provisions of RS 2477 that states "the right-of-way for the construction of highways across public lands not reserved for public purposes is hereby granted". Additionally, about 13 miles of Utah State Highway 45 extends through the GDBR and provides the main access to the GDBR from Vernal.

The GDBR consists of about 146 sections (98,785 acres) in an existing oil and gas producing region. The GDBR is located primarily on lands administered by the Bureau of Land Management (BLM) (83,864 acres), lands administered by the State of Utah (11,448 acres), and a small number of private landowners (3,473 acres). QEP operates the majority of the mineral lease rights (79.2 percent) underlying both the public and private lands in the Project Area.

As a plan of long-term development, subject to potential change as conditions warrant, QEP proposes to drill additional wells at the rate of 100 to 120 wells per year over a period of 10 years, or until the resource base is fully developed. The total number of wells drilled would depend largely on factors out of the Company's control such as geologic success, engineering technology, economic factors, availability of commodity markets and lease and unit stipulations and restrictions. At full field development, a maximum 1,239 wells could be drilled. Based on current success rates in the GDBR, it is assumed that 5 percent of the wells drilled would be dry holes. Because the well locations are conceptual and it would be impossible to know where dry holes would be, the Proposed Action considers the full-field development of 1,239 wells. A total of 891 wells would be drilled at new locations and 348 would be drilled from existing well pads. Table 2-1 summarizes the number of wells that would be drilled in each formation and the estimated monthly drilling rate.

Oil development would occur in the Green River formation and typically would be done as a waterflood based on 40 to 80-acre well spacing, dependent upon geologic, engineering and economic factors. QEP would drill approximately 50 percent of the proposed Green River wells as producing wells and 50 percent of the proposed Green River wells as water injection wells. The water injection wells would allow reservoir pressure to be managed and oil recovery to be maximized. Water for the project would be supplied from existing Green River water rights and from water produced in association with oil from existing Green River Formation wells.

Table 2-1. GDBR Well Development (Proposed Action)

Formation	Type	Drilling Rate (Wells/Month)	Proposed New Wells		
			Total	On New Pads	On Existing Pads [b]
Uinta	Gas	0-1	16	16	0
Green River	Oil	0-3	219	189	30
Green River	Gas	0-3	148	132	16
Wasatch	Gas	0-6	451	249	202 [a]
Mesaverde	Gas	0-1	68	53	15
Blackhawk/Mancos	Gas	0-3	311	246	65
Frontier/Dakota	Gas	0-1	26	6	20
			1239	891	348

[a] 132 Wasatch wells would be directionally drilled at 20-acre spacing from existing 40-acre spacing pads

[b] 216 wells would be "twins" drilled to a different formation from an existing or newly constructed pad.

Gas development would continue and potentially begin in a number of different horizons, the shallowest being the Uinta Formation with the Wasatch Formation located stratigraphically below the Uinta. Wasatch wells are currently drilled on 40-acre spacing. However, infill drilling on 20-acre spacing could prove to be necessary to effectively encounter and drain these multiple-stacked fluvial channel sequences. QEP typically drills approximately 2000 feet into the Wasatch Formation at a total depth of approximately 7750 feet across the EIS area. As many as 132, 20-acre wells are to be considered as a part of this Proposed Action. These 20-acre infill wells would typically be drilled directionally off of the same 40-acre spaced well pads, requiring no additional surface disturbance.

Twenty locations for potential development of the deeper Blackhawk and Mancos on 160-acre spacing have been identified in the already developed areas in and around Wonsits Valley. These wells would be located in the center of quarter-section pads that would allow deep test wells to be drilled vertically and still provide useful information in evaluating the 20-acre infill potential of the Wasatch.

The deeper horizons (i.e. Lower Mesa Verde, Blackhawk, Mancos, Frontier, Dakota, Nugget, Phosphoria, and Weber) are presently not extensively evaluated in the area. However, recent exploratory drilling and successful completions in the Blackhawk and Mancos have resulted in development locations for those formations being included in the Proposed Action. Similarly, locations have been identified in this study for additional development of the Lower Mesaverde and the Frontier/Dakota, but they are highly speculative at this time. Required infrastructure includes well pads, with pumping units for oil wells, separator heaters for gas wells, central facilities, electric power lines, roads, oil and gas flowlines and pipelines, water injection facilities, gas treatment and compression facilities. Produced oil from new wells would be transported from the wellhead via pipeline, to central gathering facilities then via pipeline or truck to refineries near Salt Lake City, Utah. Gas would be transported via pipeline to centralized compression and treatment facilities and then transported out of the GDBR via existing sales pipelines. Produced water would be trucked or piped to existing and proposed QEP water injection plants where it would be re-injected into the oil reservoir or disposal zone.

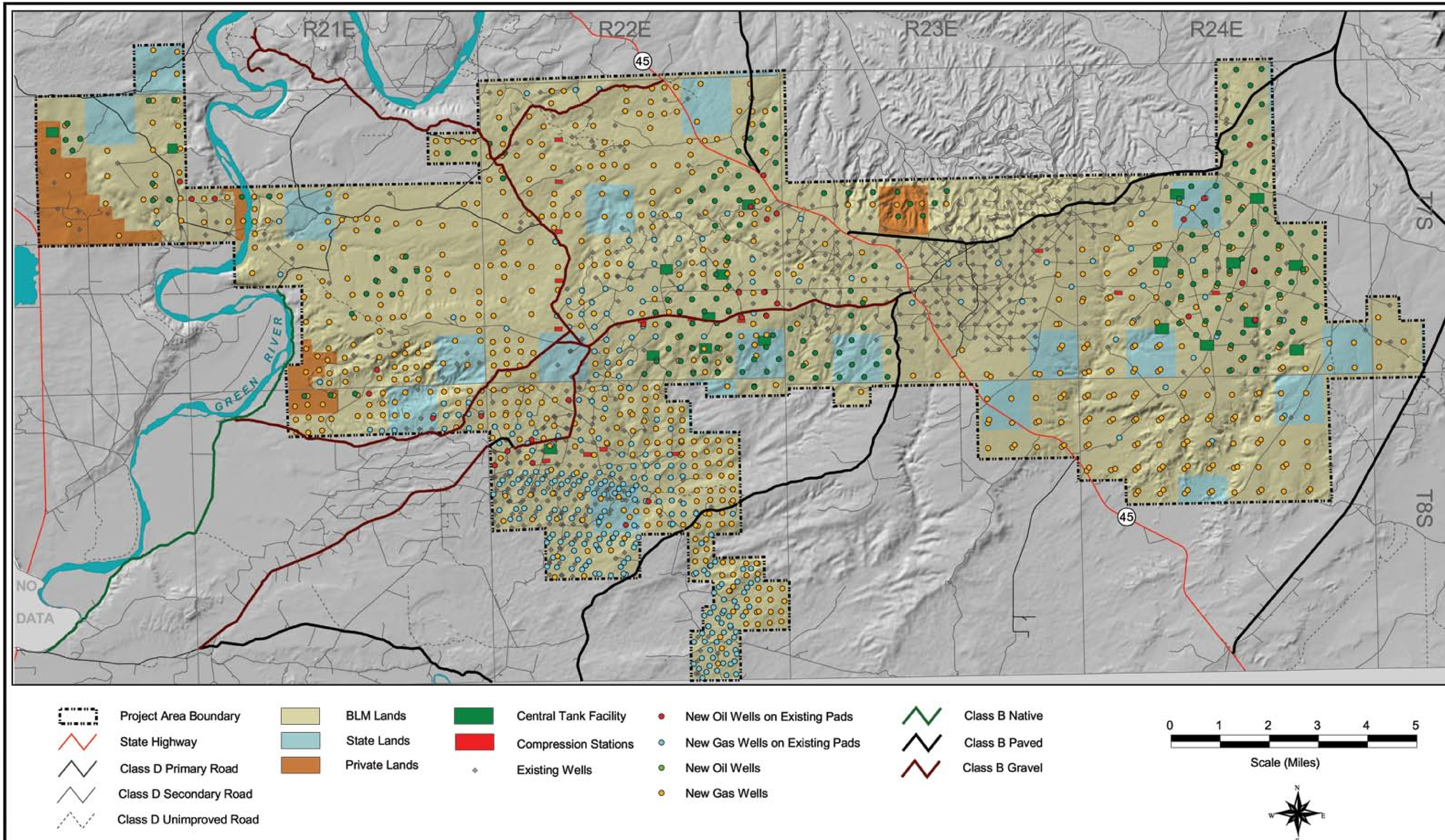

Figure 2-1. Greater Deadman Bench Proposed Action.

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2.1.1 Construction

2.1.1.1 Well Pad and Access Roads

Once an APD is approved, and subject to the Conditions of Approval, access road and well site construction would begin. Construction would generally occur only during daylight hours and fire suppression equipment would be available. First, an access road would be constructed to each proposed well pad location connecting the pad to the nearest established road. The existing road network within the EIS analysis area would provide the primary access routes to the new well sites. Over 370 miles of existing County claimed (class B & D) roads would be used, thereby minimizing additional surface impact. These roads within the GDBR are claimed by Uintah County per the RS 2477 process. The Class B roads are maintained by Uintah County, but the Class D roads are not maintained by the County. Although the length of access roads within the GDBR would vary, an average length would be approximately 1000 feet with a 30-foot right-of-way (ROW) resulting in approximately 0.69 acres of surface disturbance.

All roads would be constructed with appropriate drainage and erosion control features and structures to include cut-and-fill slope and drainage stabilization, relief and drainage culverts, water bars and wind ditches similar to those described in the BLM/USFS Surface Operating Standards for Oil and Gas Development (BLM and USFS 2006). Access roads would be constructed using standard equipment and techniques. Bulldozers and/or road graders would first clear vegetation and topsoil from the right-of-way. These materials may be windrowed for future redistribution during the reclamation process.

The well pad would be constructed from the native sand/soil/rock materials present and leveled by standard cut-and-fill techniques using a bulldozer, grader, front-end loader, or backhoe. The well pad would be a level 300 feet X 350 feet rectangular pad occupying approximately 2.41 acres (See Figure 2-2). A small reserve pit (150 feet x 70 feet x 12 feet deep, approximately 0.24 surface acres) would be excavated adjacent to the pad. Unless specified in the site specific APD, the reserve pit would be constructed on the location and would not be located within natural drainages, where a flood hazard exists or surface runoff would destroy or damage the pit walls. As described below, the reserve pit would be constructed to minimize the risk of leakage breakage, or discharge of liquids. Construction would involve preparing a level area for the equipment that would be used to drill and complete a well. First, vegetation would be cleared. Then, topsoil would be stripped to a depth determined by the BLM and stockpiled in an area adjacent to the pad and maintained for future reclamation of the pad. Depending on the amount of cut and fill required to level each site, these stockpiles would occupy approximately 0.5 acres.

The requirement for lining the reserve pit would be site-specific and would be based upon the Authorized Officer's (AO) evaluation during the APD process. Historically, pit liners have not been required at all locations. Generally, a pit liner is not required in clay or bentonite soils while a liner is usually required in sandy soil and fractured shale. If it would be determined during the on-site inspection that a pit liner is necessary, the reserve pit would be lined with a synthetic reinforced liner, a minimum of 12 millimeters thick and sufficient bedding would be used to cover rocks. The liner would overlap the pit walls and be covered with dirt and/or rocks to hold it in place.

QEP would also take measures to protect the public, livestock, and wildlife from hazards at oil and gas facilities. As directed by the AO, warning signs and fencing would be posted around reserve pits, as required by regulations to prevent unauthorized access and alert the public to potential hazards in the area.

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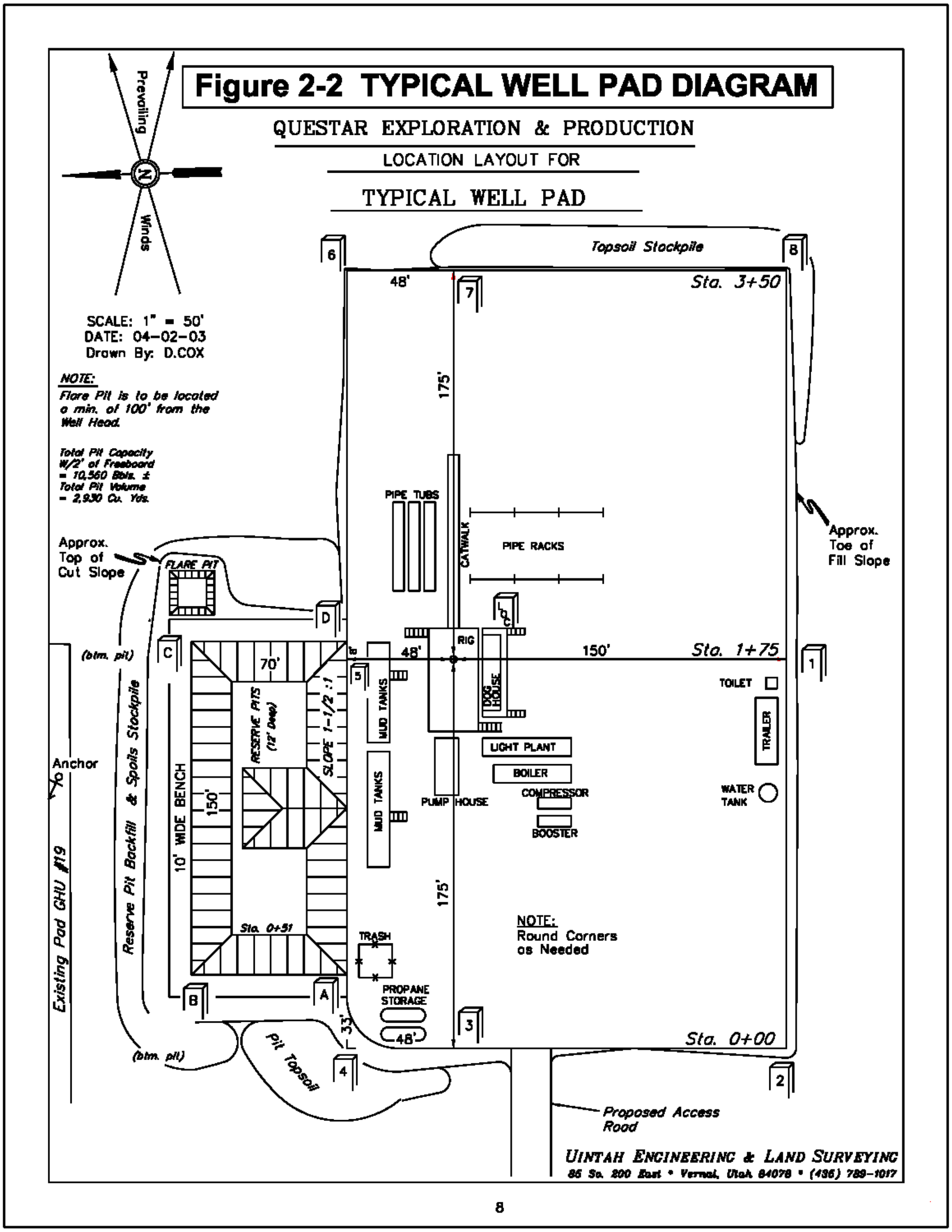

Figure 2-2 TYPICAL WELL PAD DIAGRAM
QUESTAR EXPLORATION & PRODUCTION
LOCATION LAYOUT FOR
TYPICAL WELL PAD
Prevailing Winds
N
SCALE: 1" = 50'
DATE: 04-02-03
Drawn By: D.COX
NOTE:
Flare Pit is to be located a min. of 100' from the Well Head.
Total Pit Capacity W/2' of Freeboard = 10,560 Bbls. ±
Total Pit Volume = 2,930 Cu. Yds.
Topsoil Stockpile
Sta. 3+50
48'
175'
PIPE TUBS
CATWALK
PIPE RACKS
Approx. Toe of Fill Slope
Approx. Top of Cut Slope
FLARE PIT
(btm. pit)
70'
RESERVE PITS (12' Deep)
SLOPE 1-1/2 :1
MUD TANKS
RIG
DOG HOUSE
150'
Sta. 1+75
TOILET
TRAILER
LIGHT PLANT
BOILER
COMPRESSOR
BOOSTER
PUMP HOUSE
WATER TANK
Anchor
Reserve Pit Backfill & Spoils Stockpile
10' WIDE BENCH
150'
Existing Pad GHU #19
Sta. 0+51
TRASH
PROPANE STORAGE
NOTE:
Round Corners as Needed
33'
48'
Sta. 0+00
Pit Topsoil
Proposed Access Road
UINTAH ENGINEERING & LAND SURVEYING
85 So. 200 East • Vernal, Utah 84078 • (435) 789-1017
8

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Following the drilling and initial completion operations, interim reclamation would begin on a portion of the pad plus the reserve pit. Interim reclamation would be attempted and long-term disturbance would be reduced to approximately 2.34 acres per well and access road from the initial disturbance of 3.34 acres. If a well would be determined as a dry hole when drilling ceases, it would be plugged & abandoned (P&A) per applicable regulations, the interim reclamation process would begin on the entire well location and its access road. For planning purposes, QEP assumes 5 percent of the proposed new wells would be dry holes. However, it is assumed that all wells would be productive for the analysis of impacts.

2.1.1.2 Pipelines

The gas gathering system for the Wasatch, Mesaverde, Blackhawk/Mancos, and Frontier/Dakota development program would be a surface system with 8-inch laterals and 3-inch lines connecting the wells to the laterals. These laterals would deliver the gas stream to the compressor station in Wonsits Valley (T8S R20E Section 12) where it would be compressed and sent through a 16-inch buried high-pressure line to the 24B gas plant at Red Wash (T7S R23E Section 24) where the liquids would be removed and the gas would be transferred to sales pipelines. Gas extracted from wells in the eastern part of the GDBR would be delivered directly to the 24B gas plant at Red Wash for processing and transfer to sales pipelines.

Heat-traced surface oil flow line, approximately 1000-feet in length in a 30-foot ROW from the well to a central tank battery facility, would be needed for Green River Formation oil wells. For each Wasatch, Mesaverde, Blackhawk/Mancos, and Frontier/Dakota Formation gas wells, a gas gathering line approximately 1000-feet in length in a 30-foot ROW would be required. These pipelines would be placed on the surface. Although a 30-foot ROW would be granted for each pipeline segment, minimal disturbance would occur during the construction of these surface pipeline segments because no excavation would be required. However, a full disturbance of the ROW is assumed for the project disturbance analysis.

Construction of surface pipelines would consist of laying the pipe, welding segments, and testing. While vegetation clearing would be minimized, a 30-foot ROW would be reserved for the surface pipelines. Generally, a mile of surface pipeline would take less than a day to construct.

Water pipelines would be required for the Green River waterflood operations. These pipelines would be buried to a depth of 4 to 5 feet to prevent freezing of the water flowing through the pipe. Construction of water pipelines would proceed in a planned sequence of operations. The path would first be cleared of heavy brush by blading the surface. Brush would be left in place where possible. The pipeline trench would be excavated mechanically to a depth that would allow approximately 4 to 5 feet to be placed on the top of the pipeline. Pipe segments would then be welded together and tested, lowered into the trench, and covered with excavated material. Then, each pipeline would be tested with pressurized fresh water (hydrostatic testing) to locate any leaks. Water used for testing would be collected and disposed of at water injection facilities. Generally, a mile of buried pipeline would be constructed in 4 to 5 days.

Generally, water source lines would be either 6-inch or 8-inch steel line pipe and injection lines would be 3-inch steel line pipe. Source water lines would be designed for 500 pounds per square inch (psi) service and injection lines would be designed for 3,000-psi service. Water lines would be buried 4 to 5 feet deep to avoid freezing along a ROW that is generally 30 feet wide for construction and 20 feet wide for operations. Reclamation efforts on the surface over the buried water lines would begin following installation. Between 10 and 20 miles of new injection lines would be installed to service new injection wells in the Project Area.

2.1.1.3 Ancillary Facilities

Two types of ancillary facilities would be installed as needed for the full development of the Proposed Action. Construction techniques for clearing and grading of the ancillary sites would be similar to the construction practices for well pads.

A central tank facility (CTF) would be operated to separate saleable oil from produced water. Twenty-two new CTFs would be required to service 229 new Green River Formation oil wells because of the geographical separation of well sites. Each CTF would consist of two 500-barrel (bbl) oil tanks, two heated separators, a station pump powered by a 30-hp electric motor, and one 1.5 MBtu boiler. Each CTF would require approximately 2.5 acres of surface disturbance with an electric utility line approximately 1500 feet in length in a 30-foot ROW. Construction of a CTF would take approximately 30 days.

Extra compression would be required throughout the GDBR to move gas from the wellhead as wellhead pressures gradually decrease over time. QEP plans to construct 15 new compressor stations each consisting of natural gas-fired 2,000 horsepower engines. The engines would not be enclosed in buildings. Each compressor site would occupy approximately one acre. Construction of each compressor site would take about 10 days.

2.1.2 Drilling Operations

Drilling operations would be conducted in compliance with all Federal Oil and Gas Onshore Orders, all State of Utah Division of Oil, Gas, and Mining rules and regulations, and all applicable local rules and regulations.

Drilling practices that would be used by QEP for Green River Formation oil and gas wells are provided in the Green River Formation Standard Operating Practices. Drilling and completion practices that would be used by QEP for Wasatch Formation gas wells are provided in the Wasatch Formation Standard Operating Practices. The drilling practices for these formations are described below.

The drilling operation would be conducted in two phases. The first phase would utilize a small drilling rig (similar in type to a water well drilling rig) to drill to a depth of approximately 600 –1000 feet or 50 feet below any freshwater aquifers encountered. All indications of usable water shall be reported to the BLM AO prior to running the next string of casing or before plugging orders are requested, whichever occurs first. QEP’s standard operating procedures state that the BLM would be notified within 24 hours if any aquifers are encountered. The surface hole would be cased with steel casing and cemented in place entirely from about 600-1000 feet up to the surface. This surface casing would serve the dual purpose of providing protection for any freshwater aquifers present and as a safety feature to contain any abnormal pressure that may be encountered while drilling deeper. The BLM would be notified in advance of running surface casing and cement in order to witness these operations if so desired. This part of the drilling operation would normally take 2 to 3 days to complete.

Following the use of the surface-hole rig, a larger drilling rig would be mobilized to drill the remainder of the hole to a depth of about 12,500 –14,000 feet. Prior to drilling below the surface casing, a Blow Out Preventer (BOP) would be installed on the surface casing and both the BOP and surface casing would be tested for pressure integrity. The BOP and related equipment will meet the minimum requirements of Onshore Oil and Gas Order No. 2, and the BLM would be notified in advance of all pressure tests in order to witness these tests if so desired.

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

The primary purpose of the reserve pit is to receive the drill cuttings from the wellbore (mainly shale, sand, and miscellaneous rock minerals). A secondary purpose of the reserve pit is to contain drilling fluids carried over with the cuttings, and fluids that are periodically discharged from the rig's steel tanks (usually to flush out cuttings that have settled in the tanks). No hazardous substances would be placed in this pit. QEP normally installs synthetic pit liners in this drilling program, except if BLM approval to proceed with an unlined pit is granted. The BLM would determine on a case-by-case basis if unlined pits are acceptable, or if site-specific conditions indicate that a synthetic liner in the fluid reserve pit is appropriate.

Upon drilling the intermediate hole to 5000-7000 feet, a series of logging tools would be run in the well to evaluate the potential hydrocarbon resource. Then steel production casing would be run and cemented in place from surface to 5000-7000 feet, in accordance with the well design, as approved by the BLM in the APD and any applicable Conditions of Approval. The casing and cementing program would be designed to isolate and protect the shallower formations encountered in the wellbore and to prohibit pressure communication or fluid migration between zones. The BOP equipment would be re-tested prior to drilling the final section of the well below this intermediate casing point.

Upon drilling the hole to the total depth, a series of logging tools would be run in the well to evaluate the potential hydrocarbon resource. If the evaluation concludes that adequate hydrocarbon resources are present and recoverable, then steel production casing would be run to total depth and cemented in place in accordance with the well design, as approved by the BLM in the APD and any applicable COAs. The casing and cementing program would be designed to isolate and protect the various formations encountered in the wellbore and to prohibit pressure communication or fluid migration between zones.

The time required to drill would depend on the target formation. Table 2-2 lists the approximate time required to drill and complete the wells proposed in the GDBR. The average water requirement for drilling would be approximately 5,000 barrels per well.

Table 2.2. GDBR Drilling and Completion Times

Formation	Depth of Drilling (feet)	Drilling Time (days)	Completion Time (days)
Green River	3,500 – 5,000	7	4-6
Wasatch	5,500 – 8,000	10	4-6
Mesaverde	6,500 – 10,000	14	4-6
Blackhawk/Mancos	10,500 – 14,000	50	21
Frontier/Dakota	Deeper than 16,000	90	28-42

2.1.3 Completion Operations

Once production casing has been cemented in place, the drilling rig would be removed and a completion rig would be moved in. The well completion consists of running a Cement Bond log to evaluate the cementing integrity and to correlate (on depth) the cased hole logs to the open hole logs, perforating the casing across the hydrocarbon producing zones, and then a stimulation treatment of the formation to enhance its transmissibility of oil and gas. The typical stimulation in the area is a hydraulic fracture treatment of the reservoir, where a slurry of sand suspended in a viscous fluid (gelled water) is pumped into the producing formation with sufficient hydraulic horsepower to fracture the rock formation. The sand serves as a proppant to keep the created fracture open, thereby allowing reservoir fluids to move more readily into the well.

The typical completion operation for Green River, Wasatch and Mesaverde wells uses about 3000 - 4000 barrels of water, and normally takes 4 to 6 days to perform with most all the stimulation procedures completed as a continuous operation of one or at most two consecutive days. Deeper completions such as in the Blackhawk/Mancos and/or Dakota wells are performed in a similar manner but longer periods of time for wellbore cleanup and production testing generally occur between each stage of the completion with the initial wells in the program taking 4 to 6 weeks. Eventually that time period should be compressed to 2 weeks or less.

2.1.4 Production

2.1.4.1 Oil Wells

Wells that are successfully completed as producing Green River Formation oil wells would be equipped with a pumping unit and heated flow line to a CTF. Pumping units would be powered by electric or gas fired motors. About one half would be electric-powered and the others would be gas-powered. The pumping unit would lift fluid from the well and deliver it to a central facility via steel flowlines constructed on the surface. Approximately 1500 feet of new power lines with 30-foot right-of-ways would be needed for each of the 58 new oil well pads.

The CTF would be used to separate saleable oil from produced water. The flows from individual wells would be sent through heated separators where water, oil and gas would be separated and volumes measured. The water would be transferred via buried pipelines to water injection facilities. The oil would be transported to a lease automatic custody transfer point where it would be transmitted via pipeline to Salt Lake City or trucked to a refinery. The gas would be gathered and processed at existing compressor plants in either Wonsits Valley or Red Wash.

One CTF would be required for every 20 new producing Green River Formation oil wells. In total, approximately 22 new central tank battery facilities would be required to service 116 new and 103 twin Green River Formation oil wells.

Each CTF would consist of two 500-barrel (bbl) oil tanks, two heated separators, a station pump powered by a 30-horsepower (hp) electric motor, and one 1.5 thousand British Thermal Units (MBtu) boiler to provide the heat for the separators. Each CTF would require approximately 2.5 acres of surface disturbance with an electric utility line approximately 1500 feet in length with a 30-foot ROW. Each CTF would also have a trace system that runs to each well serviced by the CTF. The average trace system would hold about 60 barrels of glycol/water mix. Trace fluid would be heated at the CTF and circulated to and from each well through 1-inch pipe to keep the oil heated and allows it to flow through pipeline. These 22 facilities and would cause 55 acres of surface disturbance plus another 22.7 acres of power line right-of-way.

In accordance with BLM requirements, the surface equipment would be painted Carlsbad Canyon color or another color determined by the AO during the on-site inspection to blend in with the surroundings. Also per BLM requirements, QEP would prepare and submit a schematic site security diagram of the tank battery. All site security regulations specified in Onshore Oil and Gas Order No. 3 would be adhered to.

The Green River gas, produced with Green River oil, would be gathered from the individual facilities through an existing buried or heated surface gathering system to the central facilities where it would be separated and processed to remove liquids and hydrogen sulfide (H2S) if present. The preceding processes would be done at Battery #6 in Wonsits Valley or the 24B compressor plant in Red Wash. The gas would be used to fuel equipment at these sites and the excess would be sold.

All produced water inside of the Project Area would be separated at the central facilities and injected using existing waterflood injection wells or disposal systems. At individual locations, produced water would be hauled by truck to injection or disposal facilities.

2.1.4.2 Oil Well Waterflood Operations

QEP would drill approximately 50 percent of the Green River Formation wells as producing wells and 50 percent as water injection wells. The water injection wells would allow reservoir pressure to be managed and oil recovery to be maximized. Water for the project would be supplied from existing water rights and from various oil and water bearing reservoirs within the Green River formation underlying the oil field. Water is not drawn directly from the Green River flow. Rather, QEP draws water from existing five water wells, 300 to 600 feet deep, within 100 yards of the Green River high-water mark. The water rights associated with these five wells are State of Utah 49-251, 49-279, 49-280, 49-296, and 49-297. The allocation for these five wells is 1.3 cubic feet per second (cfs), 941.15 acre-feet per year (ac-ft/yr) for each well, and a total allocation of 4,705 ac-ft/yr. . At its peak water usage, the waterflood operations would require about 2,300-acre feet per year, or just less than half of their annual allocation..

QEP's expanded waterflood operations would include 4 new water filtration/injection plants with injection capacities ranging from 2,000 to 6,000 barrels of water per day (BWPD). These water filtration/injection plants would be co-located on CTFs. Existing water supply sources would provide water to injection pumps through storage tanks or direct means, depending on the water quality of the source. A network of high-pressure injection lines would supply water from injection facilities to injection wells Injection wells would be equipped with flow meters and choke valves to regulate injected water volumes.

Underground Injection Control (UIC) is regulated through the Utah Division of Oil, Gas, and Mines (UDOGM), the U.S. EPA, or both agencies depending on the injection well location. These agencies review and monitor well integrity to ensure well injection water is isolated from fresh water aquifers (underground sources of drinking water, injection pressures are below fracture gradient, and water injection sources have been permitted according to State and Federal regulations. Wellbore schematics are included with each permit for a new injection well and for all other wells within 0.5-mile radius of the new injection well. These schematics contain detailed information concerning wellbore tubulars, cementing data, completed intervals, and wellhead configuration.

Monthly injection volumes and pressures would be provided to the State of Utah. Well injection rates and pressures would be measured continually through the use of surface monitoring devices at each injection well. In addition, annual well casing integrity tests would be performed as mandated by the State and EPA to ensure isolation of the injection interval.

The estimated new water requirements for the proposed expanded waterflood area range from 15,000 to 19,000 BWPD. This water requirement would be met from surface water via existing water rights with the State of Utah which allow for approximately 40,000 BWPD to be withdrawn from the Green River, and underground water produced from the Green River Formation associated with Green River oil production. At its peak water usage, the project would require about 2,300 acre-feet per year. All of the water would be supplied by water from the Green River.

Water associated with oil and water bearing formations in the Green River Formation is confined to encapsulated sandstone reservoirs at depths ranging from about 5,000 to 6,300 feet below the surface. Water from these formations contains Total Dissolved Solids ranging from 20,000 to 45,000 PPM, making it unsuitable for domestic or agricultural use. This water is currently being brought to the surface and reinjected by existing waterflood operations in the EIS analysis area. As additional wells are drilled for the proposed waterflood, additional water from these formations would be brought to the surface and reinjected by the new waterflood wells. All produced water would be permitted, monitored, and reported to the appropriate State and Federal agencies. If necessary, alternative water sources would be permitted through the appropriate government agency.

2.1.4.3 Gas Wells

Wasatch, Mesaverde, Blackhawk/Mancos, and Frontier/Dakota Formation gas wells would be completed as flowing wells through a separator where the water and condensate are captured in separate tanks. Both fluids would be trucked from location as necessary and disposed of or sold. The gas stream would be connected to the existing gathering system, which would be expanded to handle production from proposed new gas wells. Most gas wells would be ultimately placed on a plunger lift system to lift these liquids as the pressure associated with the gas stream diminishes with depletion.

The gas gathering system for the Wasatch, Mesaverde, Blackhawk/Mancos, and Frontier/ Dakota development program would be a surface system with 8-inch laterals and 3-inch lines connecting the wells to the laterals. These laterals would deliver the gas stream to the compressor station in Wonsits Valley (T8S R20E Section 12) where it would be compressed and sent through an existing 16-inch buried high-pressure line to the 24B gas plant at Red Wash (T7S R23E Section 24) where the liquids would be removed and the gas would be transferred to sales pipelines. Gas extracted from wells in the eastern part of the GDBR would be delivered directly to the 24B gas plant at Red Wash for processing and transfer to sales pipelines.

2.1.5 Surface Disturbance Summary

Based upon the level of development of the Proposed Action, the total long-term new disturbance to construct and operate all facilities would be 4,561 acres. The disturbance for each type of facility for the Proposed Action is summarized in Table 2.3.

Workovers would be required from time to time for both Green River Formation and for the Wasatch and for the Mesaverde, Blackhawk/Mancos, and Frontier/Dakota Formation wells to repair worn downhole equipment, to sustain existing production rates, or to recomplete the well to enhance its productivity. Completion rigs would perform workovers and typically take 1 to 5 days for routine repairs and 5 to 10 days for any recompletion operations. Workover operations would not require additional surface disturbance.

2.1.6 Water Requirements

Major water requirements would consist of water needed for drilling and completion for development, and for the Green River formation waterflood during operations. Typically, water use be would 5,000 barrels per well for drilling and 3,000 to 4,000 barrels for completion of each well. Approximately 124 wells would be drilled every year for 10 years. Annual water use for drilling and completion would be 108 acre-feet per year. Water requirements for waterflood operations would be 2,300 acre-feet/year. The resultant annual water use during the 10-year development phase would be a maximum of 2,408 acre-feet per year and would decrease to 2,300 acre-feet per year after all wells were developed.

QEP has existing water rights from five Green River wells. At a full year of withdrawal, QEP has the water rights for 4,705 ac-ft/yr. Therefore, QEP's current water rights would be more than sufficient for the GDBR project. QEP's water requirements could also be met from produced water from the Green River formation.

2.1.7 Hazardous Materials

QEP has reviewed the EPA's Consolidated List of Chemicals Subject to Reporting Under Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986 (as amended) to identify any Hazardous Substances proposed for use in this project, as well as the EPA's List of Extremely Hazardous Substances as defined in 40 CFR 355, as amended. QEP's Vernal, Utah Field Office maintains a file containing current Material Safety Data Sheets (MSDS) for all chemicals, compounds, and/or other potentially hazardous substances that would be used during construction, drilling, completion, production and gas gathering operations in the GDBR. Hazardous Substances that would be used in this project for drilling and completion are also identified in the Standard Operating Practices that are included as Appendix 2-1.

QEP would develop drilling and operational plans that cover potential emergencies including fire, employee injuries, chemical releases, and spill prevention. QEP and its contractors would comply with all applicable Federal laws and regulations existing or hereafter enacted or promulgated governing the location, handling and storage of hazardous substances. QEP and its contractors would locate, handle, and store hazardous substances in an appropriate manner that prevents them from contaminating soil and water resources or otherwise sensitive environments. Any release of hazardous substances (leaks, spills, etc.) in excess of the reportable quantity as established by 40 CFR, Part 117, would be reported as required by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as amended. If the release of a hazardous substance in a reportable quantity would occur, a copy of a report would be furnished to the BLM's Authorized Officer (AO) and all other appropriate Federal and State agencies.

QEP has evaluated its overall field operations within the GDBR and has prepared and implemented Spill Prevention, Control and Countermeasure (SPCC) Plans. The plans include accidental discharge reporting procedures, spill response and cleanup measures, and maintenance of dikes, and copies are kept at QEP's Vernal, Utah field office as well as the Denver, Colorado office. A Hazardous Communication Program also is kept at QEP's Vernal field office, and SARA Title III (community right to know) information is submitted yearly as required and copies are kept in QEP's Denver office, as well as in QEP's Vernal field office.

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Table 2.3. GDBR Proposed Action Surface Disturbance Summary

Formation	Description	Wells	Pad Construction	Road	Flow Lines	Gas pipelines	Power Lines to 22 CTFs	Power Lines to 108 Oil Wells	22 CTFs	Water pipeline	15 Compressor Stations
Green River Oil	New pads	188	595	130	130						
	On existing pad	31			21						
Uinta Gas	New pads	16	50	11		11					
	On existing pad	0									
Green River Gas	New pads	132	416	91		91					
	On existing pad	16				11					
Wasatch 40-ac Gas	New pads	252	784	172		172					
	On existing pad	67				48					
Wasatch 20-ac Directional Gas	New pads	0	0	0							
	On existing pad	132				91					
Mesaverde Gas	New pads	53	167	37		37					
	On existing pad	15				10.4					
Blackhawk/Mancos Gas	New pads	246	775	170		170					
	On existing pad	65				45					
Frontier/Dakota Gas	New pads	6	19	4		4					
	On existing pad	20				14					
	Total new gas wells	1020									
	Total new oil wells	219									
	Wells on new pads	893									
	Wells on existing Pads	346									
	Total new wells	1239									
Total Disturbance	Acres	**4561**	2813	616	151	704	23	106	55	73	15
Total long-term disturbance if interim reclamation would be successful		**3148**									
Total Linear Disturbance	Miles		NA	169.1	41.5	193.2	6.3	30.7	NA	20.0	NA

3.15 acres/pad for short term includes 300X350 pad (2.41), 150X70 reserve pit (0.24), and 0.5 acre topsoil stockpile
1.65 acres/pad if interim reclamation would be successful
Roads and pipelines are assumed to be 1,000 ft. x 30-ft. ROW. Compressor stations – 1 acre; CTFs - 2.5 acres.
Power lines are assumed to be 1,500 ft. x 30-ft. ROW. Water pipelines are total of 20 miles in a 30-ft construction ROW all to be reclaimed after construction.

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2.1.8 Reclamation

Prior to abandonment of any well, location, access road or other facility, QEP would file with the BLM a Form 4: Notice of Intent to Abandon, detailing the proposed Plugged and Abandoned (P&A) procedures. Upon BLM approval, wellbores would be plugged with cement as necessary to prevent fluid or pressure migration, and to protect mineral and/or water resources. Wellheads would be removed, both the surface casing and production casing would be cut off below ground level, and an appropriate dry hole marker would be set in compliance with Federal and State regulations.

All surface equipment and above ground flow lines and gas system pipelines that had been installed would be removed from the site. Underground pipelines would be purged and retired in place.

The well pad, reserve pit (if not previously done), and access road would be reclaimed as per BLM requirements. At a minimum, reclamation efforts would include backfilling the pit, contouring the surface to its original appearance, and distributing the topsoil to blend the site in with its natural surroundings. A seed mixture of desired grass and plant species, as per the BLM's specifications, would then be planted on project-related disturbed areas.

2.1.9 Workforce

The majority of the workforce requirement would be for construction, drilling and completion. Afterwards, a minimal workforce would be required to operate and maintain the facilities. Most workers would likely reside within 50 miles of the GDBR and commute daily.

2.1.9.1 Construction

Construction of a well pad and the associated access road would take about 4 days. Five people would operate construction equipment (bull dozers, back hoes, front end loaders, and graders) for about 12 hours per day. Approximately 5 round trips would be required to transport equipment to the site and another 8 round trips would be necessary for workers traveling daily to the construction sites.

2.1.9.2 Drilling

Drilling would be a 24-hour per day operation involving three shifts of 7 people. Drilling times would vary from 7 days for the shallower oil and gas wells to a maximum of 90 days for the deeper formations. Large trucks would be needed to transport the drill rigs and other equipment to the site. Other large trucks would transport fuel, water, and other materials on a daily basis. Three round trips a day would be required for workers. Depending on the depth of the well to be drilled, vehicle round trips would range from 71 to 735 for the duration of drilling activities.

2.1.9.3 Completion

Completion would be a 24-hour hour per day operation involving 3 shifts of 7 people. Completion operations on a well would take from 6 to 42 days depending on the depth of the formation. Required equipment would include truck mounted rigs, sand trucks, pump trucks, frac trucks, tanker trucks, and others. Depending on the depth of the well to be completed, vehicle round trips would range from 41 to 215 for the duration of completion activities.

2.1.9.4 Pipelines

Approximately 6 workers would be needed for two to three days to install buried water pipelines. The same number of workers would require an average of only one day to install short surface gas pipelines and oil flow lines. Equipment requirements would include a backhoe, welding truck, hydrostatic testing equipment, and pickups for worker transportation.

2.1.9.4 Operations

Upon completion of all drilling, completion, and testing activities, the workforce would be minimal. A maintenance person (”pumper”) would visit each well daily during production to monitor well operations. One pumper would generally be responsible for 30 wells. At full production, 41 pumpers would be employed to monitor 1,239 wells under the Proposed Action.

Periodically, a workover procedure on the well would be required to ensure that the well facilities are maintained in good condition and are capable of continuing efficient operation. A crew of 5 workers could do routine maintenance in one day. However, more detailed workovers could take five days to complete. It is expected that each well would require a workover every 2 to 3 years.

Table 2.4 lists the estimated workforce requirements for the Proposed Action based on the assumptions listed above.

Table 2.4. Proposed Action Estimated Workforce Requirements

Category	Project Total	Workers per Activity	Duration (days)	Worker Days Total 10-Year Construction Period	Worker Days per Year	Workers per Year [1]
Pad/Access Road Construction	893	5	4	17,860	1,786	6.9
Water pipeline (miles)	20	5	3	300	30	0.1
Gas or oil surface pipeline/flowline (1000-ft segments)	1,239	5	1	6,195	620	2.4
Drilling (wells)						
Green River	367	21	7	53,949	5,395	20.8
Uintah	16	21	7	2,352	235	0.9
Wasatch	451	21	10	94,710	9,471	36.4
Mesaverde	68	21	14	19,992	1,999	7.7
Blackhawk/Mancos	311	21	50	326,550	32,655	125.6
Frontier/Dakota	26	21	90	49,140	4,914	18.9
Completion (wells)						
Green River	367	21	6	46,242	4,624	17.8
Uintah	16	21	6	2,016	202	0.8
Wasatch	451	21	6	56,826	5,683	21.9
Mesaverde	68	21	6	8,568	857	3.3
Blackhawk/Mancos	311	21	21	137,151	13,715	52.8
Frontier/Dakota	26	21	42	22,932	2,293	8.8

Category	Project Total	Workers per Activity	Duration (days)	Worker Days Total 10-Year Construction Period	Worker Days per Year	Workers per Year [1]
Workovers per year	620	5	5	15,500	1,550	6.0
Workers/Year (Development)					86,029	331
Operations (pumpers)	30	41	365			41
Operations (staff)	30	20	260			20
(Employees/Year Operations)						61

[1] 260 worker-days = 1 worker-year

2.2 NO ACTION

The No Action alternative is denial of QEP's proposal. Under the No Action Alternative, the oil and gas development on federal lands under the Proposed Action would not be implemented. The No Action alternative analyzes a level of development that would occur if no new authorizations were allowed on federal leases in the project area. However, APDs for 79 federal wells have been approved based on other NEPA documents, and these wells could be developed. In addition, 130 wells would be on State of Utah and private leases. Therefore, the No Action Alternative would result in a maximum level of development of about 209 wells that would include 177 natural gas wells and 32 oil wells. The location of wells under the No Action Alternative is shown on Figure 2-3.

For the EIS analysis, the following is assumed:

- a new well pad would be constructed for 90 percent of the wells;
- a 1,000-foot access road would be required for each well;
- 1000-foot pipelines or flowlines would be required for each well;
- 3 new 2,000 horsepower compressor stations would be constructed; and
- 3 new central tank facilities would be constructed.

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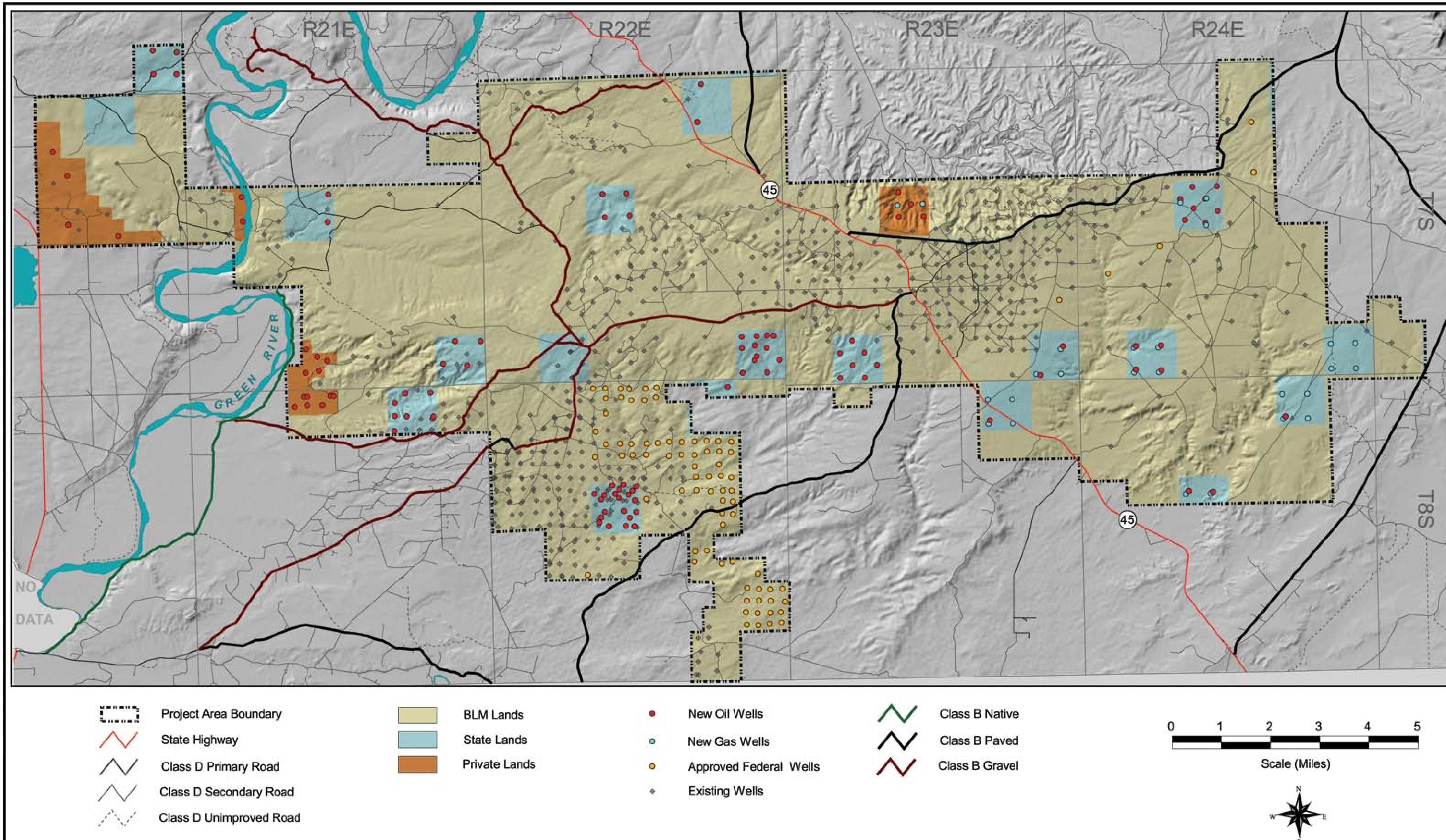

Figure 2-3. Greater Deadman Bench No Action.

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As described in Table 2.5, long-term surface disturbance would be 548 acres. Construction would occur over a 3-year period and each well would produce for 30 years resulting in a 33-year life of the project.

Table 2.5. GDBR No Action Surface Disturbance Summary

Type Well	# Wells	Well Pad (acres)	Access Road (acres)	Pipeline/ Flowline (acres)	3 CTFs (acres)	3 Compressor Stations (acres)
Federal Oil New Pad	2	6	1	1		
Federal Gas New Pad	77	242	53	53		
State Oil New Pad	18	56	12	12		
State Gas New Pad	66	207	45	46		
State Oil Existing Pad	4	0	3	3		
State Gas Existing Pad	18	0	12	12		
Private Oil New Pad	8	25	6	6		
Private Gas New Pad	16	50	11	11		
Total	210	589	144	144	8	3
Total Disturbance (acres)		**888**				
Linear Disturbance (miles)			**40**	**40**		
Total Long-term Disturbance if Interim Reclamation Would be Successful (acres)		**607**				

3.15 acres/pad for short term includes 300X350 pad (2.41), 150X70 reserve pit (0.24), and 0.5 acre topsoil stockpile
1.65 acres/pad if interim reclamation would be successful
Roads and pipelines are assumed to be 1,000 ft. x 30-ft. ROW.
Power lines are assumed to be 1,500 ft. x 30-ft. ROW.
Water pipelines are total of 20 miles in a 30-ft construction ROW all to be reclaimed after construction.
Compressor stations – 1 acre; CTFs - 2.5 acres.

2.3 APPLICANT-COMMITTED MITIGATION AND BEST MANAGEMENT PRACTICES

The following are applicant-committed mitigation including some environmental best management practices taken from WO IM 2007-021.

In addition to these applicant-committed BMPs, the BLM on-site inspection for each new well site may identify specific resources that may be affected on a particular location. The on-site inspection would be used in conjunction with the measures described below to develop site-specific mitigating measures for sensitive resources.

2.3.1 Cultural Resources

A Class III cultural resources survey, conducted by a qualified archaeologist, would be conducted over all areas proposed for surface disturbance. Class III cultural resource block surveys have been conducted in portions of the proposed development area and would be utilized where applicable. If these surveys identify areas with a high probability of encountering potentially significant subsurface archaeological sites, a qualified archaeologist would monitor surface disturbance. QEP and their contractors would inform their employees about relevant federal regulations intended to protect cultural resources. Equipment operators would be informed that if a site is uncovered during construction, activities in the vicinity would immediately cease and the BLM's Authorized Officer (AO) would be notified. Historic properties considered eligible for the National Register of Historic Places (NRHP) would be avoided or mitigated through a data recovery plan approved by the BLM and State Historic Preservation Officer (SHPO).

2.3.2 Paleontological Resources

Based on site-specific recommendations from the BLM’s AO, surveys for paleontological resources would be conducted on areas with sandstone outcrops and where bedrock excavation into sensitive formations is necessary. The survey would be conducted by a qualified paleontologist funded by QEP and would determine fossil localities and the sensitivity of the area for fossil resources. These actions would determine the necessity of having a qualified paleontologist on-site during construction. If paleontological resources were uncovered during ground disturbing activities, QEP would suspend all operation that would further disturb such materials and would immediately contact BLM’s AO, who would arrange for a determination of significance and, if necessary, recommend a recovery or avoidance plan in coordination with the SHPO.

2.3.3 Wildlife and Vegetation (including Federally listed, Candidate and Proposed Species)

QEP would comply with Endangered Species Act (ESA) regulations in order to prevent adverse impacts to federally listed, Candidate and Proposed wildlife and plant species. QEP would also implement appropriate protective measures (e.g., timing and spatial stipulations), shown in Table 4.6-2: Raptor Protection Dates, in order to prevent adverse impacts on wildlife species and habitats.

2.3.4 Power Lines

Unless otherwise agreed to by the AO in writing, power lines shall be constructed in accordance with the standards outlined in Suggested Practices for Raptor Protection on Power Lines, (Edison Electrical Institute 1996). QEP would construct power lines in accordance with these standards or will assume the burden and expense of proving pole designs not shown in the referenced publication are “raptor safe”. A raptor expert acceptable to the AO shall provide such proof. The AO would require modification or additions to all power line structures on route authorizations, should they be necessary to ensure the safety of large perching birds. QEP would make such modifications and/or additions without liability or expense to the Federal Government.

As directed by the AO, QEP would place raptor perch guards on power line poles in areas near sensitive wildlife habitat areas such as sage grouse leks and prairie dog towns.

2.3.5 Noxious and Invasive Weeds

QEP would monitor and control noxious and invasive weeds along access road use authorizations, pipeline route authorizations, well sites, or other applicable facilities by spraying or mechanical removal. On BLM-administered land, a Pesticide Use Proposal would be submitted and approved prior to the application of herbicides, pesticides or other hazardous chemicals.

2.3.6 Reduced Surface Disturbance Footprint

The primary objective of the BLM BMPs is to reduce the disturbance footprint of oil and gas development. QEP’s Proposed Action would minimize roads and well pads required to drill and complete 1,239 wells. QEP would construct 891 new well pads and associated 1,000-foot access roads. QEP would directionally drill 132 wells and 216 twin wells from either existing or newly constructed pads for other wells. Accordingly, QEP’s Proposed Action would require 65.9 less miles of access roads and 348 less well pads (1,096 fewer acres short-term disturbance and 574 fewer acres long-term disturbance). All existing and newly constructed roads would be maintained and kept in good repair during all drilling, completion, and production operations associated with wells. Planned access roads and surface disturbing activities would conform to standards outlined in the BLM and Forest Service publication: Surface Operating Standards for Oil and Gas Exploration and Development, 2006 (The Gold Book).

2.3.7 Interim Reclamation

After drilling and completion activities, QEP would initiate reclamation efforts to reduce the size of long-term well pads from the original disturbance of slightly over 3 acres to less than 2 acres. This reduction would be accomplished by reclamation of the drilling pit and revegetation of the portions of the pad that would no longer be needed for long-term operations.

If a new road would need to be constructed to replace an existing one, QEP would reclaim and revegetate the existing road.

2.3.8 Visual Resources

Based on site-specific recommendations from the BLM’s AO, surface equipment would be painted to blend in with the surroundings. Additionally, all surface equipment on a site (well pad, central tank facility, compressor station) would be painted the same color.

QEP would avoid, where feasible, the placement of facilities on hill tops or along ridge lines in visually sensitive areas classified as VRM Class III or higher. If facilities could not be relocated off ridge lines or hill tops in visually sensitive areas, QEP would use tanks with a smaller height as directed by BLM’s AO.

2.3.9 Existing Facilities and Rights-of-Way

Cattle guards would be used for fence crossings whenever practicable. If a fence must be cut, H-braces would be installed to support the existing fence and a cattle guard installed to prevent livestock movement.

2.3.10 Hazardous and Solid Waste/Trash Disposal

All solid waste or trash would be transported for disposal to an approved solid waste disposal facility.

2.3.11 Construction and Operations

QEP would install remote monitoring to measure production on gas and oil wells. At full development of the field, this monitoring would reduce trips to individual sites by pumpers to once every 3 days instead of daily trips.

Where directed by the AO, QEP would construct erosion control devises (riprap, bales, heavy vegetation) at culvert outlets.

QEP would use secondary containment (berms, metal containment rings) around chemical storage devises.

2.3.12 Reclamation Monitoring

QEP will work with the BLM to monitor the success of interim and final reclamation. QEP and BLM will perform annual inspections on chosen sites reclaimed 2 years prior. The 2 year gap will allow the seed to become established and give the vegetation 2 full growing seasons for a better measure of success. If QEP and the AO for the BLM determine the reclamation has not been successful, QEP will reseed the location.

2.3.13 Road Usage Monitoring

QEP will meet with the BLM, Uintah County Commission, and Uintah County Road Department once every 5 years to review usage of existing access roads inside the GDBR boundary. If it is determined by all that a certain access road is no longer used or needed, QEP will reseed the road and return it to its native condition.

2.3.14 Road Maintenance

QEP will maintain new access roads leading to their facilities inside the GDBR. Access roads are typically the 30 ft. by 1,000 ft class D roads that branch off the main Class B and D County roads.

2.3.15 Reclaiming Temporarily Abandoned Well Pads

If a well is to be temporarily abandoned for more than 3 years, QEP will revegetate the well pad with a seed mixture approved by the BLM. If the well is brought back onto production, the minimum amount of clearing needed to conduct safe operations will be done.

2.4 ALTERNATIVES CONSIDERED BUT NOT EVALUATED IN DETAIL

Several alternatives were considered as a result of issues identified during the scoping process. Potential alternatives were evaluated and some were eliminated from detailed analysis. A description of the alternatives considered follows along with a description of the rationale for not addressing these alternatives in depth.

2.4.1 No Development

A no development alternative that would deny APDs and ROWs on federal lands was considered and rejected for several reasons. There are private and state lands in the GDBR, and development could occur on these lands regardless of any decision to deny development of federal lands.

BLM cannot deny access to private holdings on non-federal land. BLM's policy concerning access to oil and gas resources on non-federal is documented in BLM Manual 2800.06D, release 2-224 (May 15, 1985). The policy directs BLM to allow access to secure to the owner reasonable use and enjoyment. Ingress and egress do not necessarily require the highest degree of access, but rather a degree of access commensurate with reasonable use and enjoyment of the land. The access necessary cannot be denied as long as the landowner complies with BLM rules and regulations on federal surface.

In addition, denial of development on federal lands could lead to the drainage of federal reserves from wells on adjacent State and private lands. A drainage stipulation designed to protect the federal mineral estate is included in the lease term contractual agreements for all leased lands in the GDBR.

A denial to develop a valid lease would violate the lessees' contractual rights and result in a loss of federal royalties. An oil and gas lease grants the lessee the right and privilege to drill from, extract, mine, remove, and dispose of all oil and gas deposits in the leased lands, subject to the terms and conditions incorporated in the lease. A denial of all activity would constitute a breach of contract of the lessees' rights to conduct developmental activities on the leased lands. Only the U.S. Congress has the authority to grant a complete denial.

In addition, none of the issues identified were of such a nature that denial of all operations would be required to resolve the issues. With the proposed action and standard lease terms, the impacts could be avoided or minimized while allowing oil and gas development. NEPA Section 102(E) requires that agencies study, develop, and describe appropriate alternative to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative use of available resources. In this case, the Proposed Action with mitigation resolves the conflicts.

2.4.2 Suspension of Operations

An alternative to delay access to certain leases for an extended period of time was considered. However, this type of delay would not change the environmental effects, but merely put off potential environmental effects for the period of the suspension of lease access. Therefore, this alternative was not analyzed further.

2.4.3 Exchange of Leases

The potential of exchanging the GDBR federal leases with leases at some other locations was considered. However, it would not be possible to determine potential effects at other locations because the locations are unknown. Furthermore, the Federal Land Policy Management Act requires that the exchanged assets would have to be of equal value. Without knowing the location or value of other leases that may be involved, evaluation of effects would be impossible.

2.4.4 Full-Field Directional Drilling

Consideration was given whether the number of new drill pads could be reduced by requiring that a single pad be used for drilling one vertical well and one or more directional wells. In concept, for example, directional wells might be used to avoid surface disturbance near prairie dog towns or near floodplains in the GDBR or simply to reduce the total acreage disturbed by new pads.

Whether directional drilling can be conducted successfully depends on site-specific geological conditions. An analysis, specific to the GDBR, was completed of the technical and economic feasibility of the use of directional drilling (QEP 2004). Based on this analysis, BLM has determined that an alternative requiring some level of directional drilling within the GDBR is not a feasible means of achieving the purpose of the proposed action. A summary of the assessment, and the primary technical and economic rationale for BLM's decision to dismiss a directional drilling alternative from detailed analysis in the EIS, is provided in the following discussion. While further consideration of an alternative based on directional drilling was determined to be infeasible, it should be understood that consideration of directional drilling as an option for a site-specific situation, as described above for example, may be appropriate.

QEP prepared a directional drilling paper for BLM review. The technical drilling and economics in the report is summarized here. Because some company-confidential information is included in the report, a copy of the report may be viewed only at the BLM Vernal Field Office in Vernal, Utah.

2.4.4.1 Technical Aspects of Directional Drilling

QEP's vertical wells are typically drilled with a combination of rotating drill pipe and downhole mud motors to turn the drill bit. On a vertical well the weight of the drill string creates a plumb bob effect and the inclination (or deviation from vertical) will normally be less than 2 degrees. This usually places the bottom hole location (BHL) within 50 to 100 feet of the surface location at a depth of 9,000 feet.

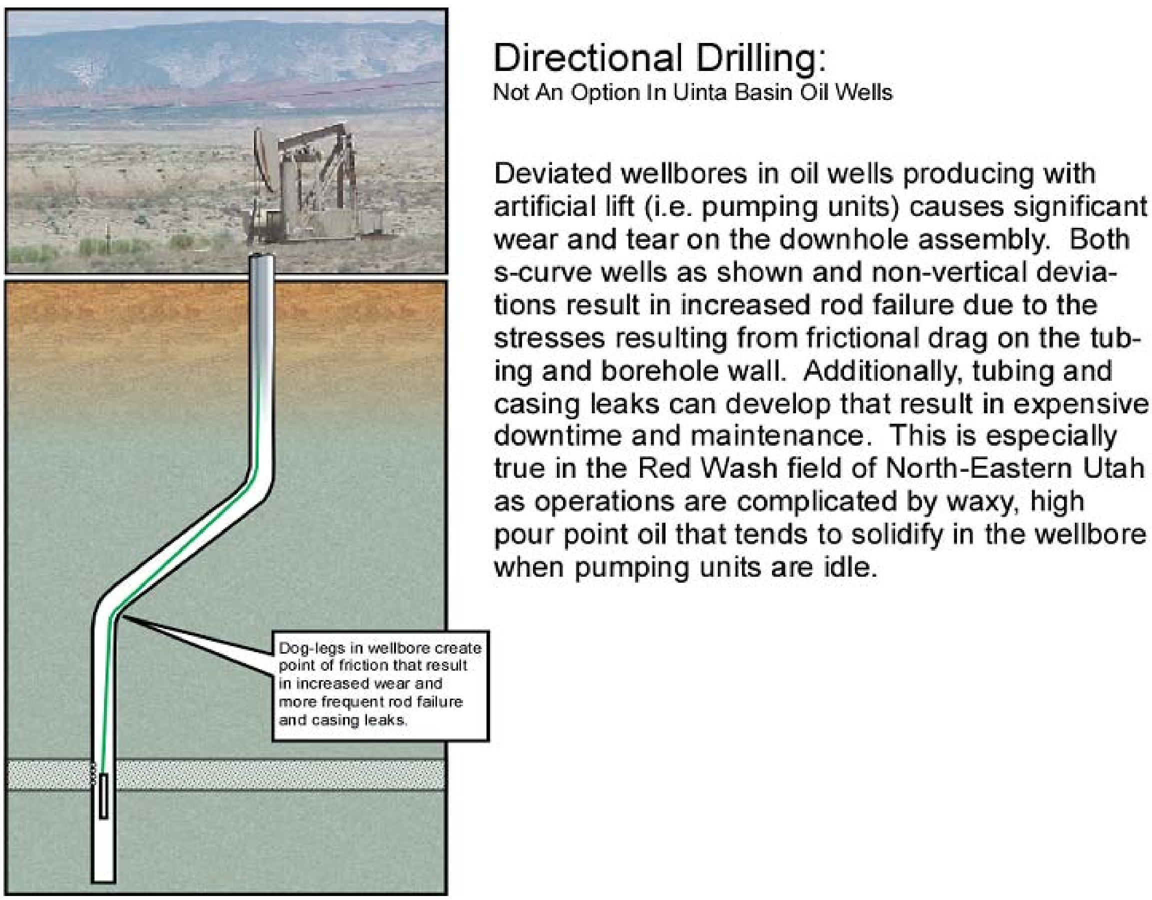
Conversely, a directionally drilled well is intentionally deviated from vertical and steered to a planned BHL which is not directly under the surface location. In order to obtain this displacement and directionally drill the well to a different BHL, the angle or inclination needs to be established in the well while drilling it. Typically, the well will be drilled vertically to a depth of approximately 1,500 feet from surface. Then a drill bit, mud motor, and special tools are run in the well to increase the angle and "steer" it towards the planned BHL. Once the angle is increased to approximately 12-15 degrees, the angle is held at this position and direction for 3,000 feet or more, until the well nears the objective (or target area). Then the angle in the well is allowed to reduce back to vertical and the productive pay zones are drilled.

With the well at total depth, the well is then electric logged, cased and cemented, and completed in the same manner as a vertical well. Drilling times on an 11,000 foot measured depth directional well are usually 3 to 4 days longer than the equivalent vertical well. This increase in drilling time (and resultant cost) plus the cost of the directional contractor to control and steer the well would amount to an increase of nearly $140,000 per well or approximately 19% more. There can also be an increase in risk associated with drilling a directional well due to the possibility for more downhole problems and sticking of the drill string or electric logs. Completion times and cost are not appreciably impacted by directionally drilling gas wells of this type.

It is technically impractical to directionally drill shallow gas wells. QEP proposes to drill 164 gas wells into the Uinta and Green River formation gas wells at depths to 1,500 to 5,000 feet. These wells are too shallow to deviate and get to a BHL. These relatively shallow directionally drilled wells would require extremely large angles, possibly 50 to 70 degrees, to reach BHLs on 160 acre offsets. These high angle directional wells would be very difficult to drill. Some of the problems very likely to occur include a higher likelihood of hole problems, loss of circulation while drilling directionally through the Bird's Nest aquifer, and a higher tendency to stick the drill string. Economically, the higher costs combined with the higher risk factors would make these wells unfeasible to drill, complete, and operate.

In addition to the shallow gas wells into the Uinta and Green River formations, QEP is proposing to drill 219 Green River formation oil and water injection wells. Of these, 188 would be on new pads, 31 would be on existing pads. The 31 wells proposed on existing pads will not be directionally drilled; instead, they will be drilled as twins. The following diagram and narrative explains why it is not technically prudent to directionally drill an oil well.

Figure 2-4 Directional Drilling



QEP is planning to directionally drill about 132 infill wells on 20-acre spacing into the Mesaverde formation to depths of near 10,000 feet. QEP acknowledges that these wells would be reasonable for directional drilling because the deviation angle would not be excessive. The distance to the BHL would be small because of the 20-acre spacing. For the 20-acre infill drilling that QEP is proposing, the planned BHL will be 800 to 900 feet vertically displaced from the wellhead at the surface location.

If directional drilling would be employed for 40-acre spacing, the planned BHL would be more than 1,800 feet. Deviations would be larger as spacing would increase to 80-acre or 160-acre. Therefore, the risk of failure to directionally drill these wells would be unacceptable unless the expected rate of economic return would be high. The following discussion demonstrates that the estimated rate of return would not be high enough to accept the technical risk of drilling deep wells on greater than 20-acre spacing.

2.4.4.2 Economic Aspects of Directional Drilling

QEP prepares an economic evaluation of all wells when they are proposed to be drilled. This evaluation is an integral part of the management authorization process. QEP recently began drilling several directional wells from a single pad at 40-acre spacing in the GDBR. Directional drilling was necessary because the topography would make it impossible to construct an individual pad and access for every well. As a result, QEP has recent well cost and economic evaluations for these wells. This data was developed by QEP’s drilling department and reservoir engineering group and is used to discuss the limitations of directional drilling to develop 40-acre Wasatch/Mesaverde reserves in the GDBR.

Two factors affect the economic viability of directional drilling: the Rate of Return (ROR) after federal income tax (as a percentage) and the Estimated Ultimate Recovery (EUR) (as bcf). The factors effecting ROR are the probability of success (POS) to drill and complete a well and the cost to drill and operate the well. Wells drilled into areas and/or depths with less known information have a lower POS. QEP has predicted a POS between 75 and near 100% for proposed GDBR wells.

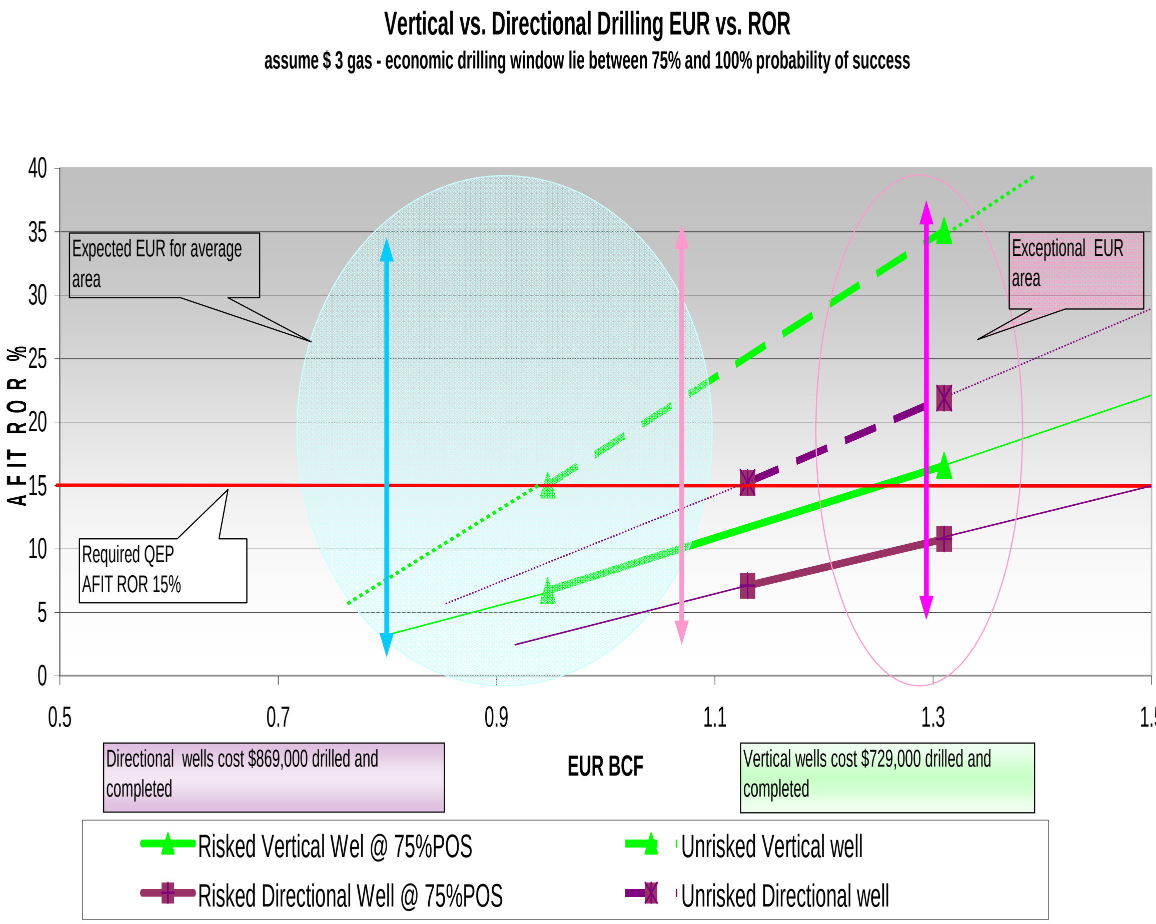
The EUR is based upon known past performance of well recoveries and future estimates for a well at a given depth and location. Of the 430 wells drilled to date in the GDBR, the EURs are currently averaging 0.8 bcf. More than 90% of these wells have been drilled just through the first 1800 feet of the Wasatch formation. In the past year, QEP has been drilling wells through the Wasatch and into the first 600 feet of the Mesaverde formation. These wells (30+) are averaging 1.08 BCF. The area in which QEP is planning to drill the directional wells in has been averaging reserves closer to 1.3 bcf or a sweet spot due to better reservoir permeability and fracture enhancement from a local structural trend.

The two data sets on Figure 2-5 represent the costs to drill a conventional vertical well and a directional well with a bottom hole 1100+ feet from the surface location. The estimated difference in cost is \$140,000 based upon a 2004 analysis. The current estimated difference is \$300,000. For each of these data sets a 100% (dashed) POS is analyzed as well as a case at 75% POS. QEP would typically expect the probability to be in the 85 to 90% range for development programs such as the GDBR. A POS greater than 85% takes into account wells that have unusually thin pay intervals, unexpected costs in drilling, failure to obtain a good stimulation, etc. The red horizontal line is set at a 15% ROR which is the internal QEP financial threshold for approving drilling projects. As shown on Figure 2-5, the EUR of directional wells would have to exceed 1.1 bcf for wells with POSs greater than 85%. This is generally not the case for the GDBR wells.

The economic viability of directional drilling derived by staying above the 15% ROR requirement and within the economic and risk for a vertical well as defined by the green solid and dashed curves. This window indicates vertical wells can be drilled well down into the average reserve range for Wasatch/Mesaverde. At higher prices this window will shift left and allow some wells at the lower end of the reserve range to be drilled.

Directional drilling does have its benefits. However, it must also be recognized that it is considered only in areas where topography is an issue, the average EURs are much higher than those typically found in the GDBR.

Figure 2-5



Of the 1,239 proposed wells, 346 would be drilled from an existing pad. Therefore, only 893 new pads are being proposed. Oil wells and shallow gas wells cannot be considered for directional drilling because of the technical difficulties and related high risk factors. The deeper gas wells may be technically feasible in some situations, but the economics will not allow management to approve the project unless it is an exceptionally high volume well.

2.4.5 Conventional Oil and Gas Plan Development

This alternative would evaluate the effects of a conventional oil and gas plan of development. QEP voluntarily proposed Best Management Practices (BMP) to reduce surface disturbance. The purpose of considering this alternative was to compare the effects to the Proposed Action. Specifically, this alternative evaluated the effects of developing each of the proposed 1,239 oil and gas wells on a separate pad. In other words, QEP would not employ directional drilling at 20-acre spacing or “twin” drilling techniques. Also, 1,239 short (1,000 feet GDBR-wide average length) access roads would be constructed and maintained for the 40-year life of the project. All other facility construction and operation would be the same as the Proposed Action.

Total short-term disturbance under this alternative would be 5,889 acres. The disturbance would include 235 miles of new access roads. Under the Proposed Action, the short-term disturbance would be 4,561 acres and 169 miles of new access roads. As described earlier in Chapter 2, the main reason for less total surface disturbance under the Proposed Action would be the 132 directional wells and 216 "twins" to be drilled on existing or other newly developed pads. As a result of the 29 percent greater surface disturbance, this alternative was not analyzed in detail.

2.4.6 Best Management Practices

Best Management Practices ("BMPs") are practices currently identified by BLM in Washington Office Instruction Memorandum 2004-194 defined as "innovative, dynamic, and economically feasible mitigation applied on a site-specific basis to reduce, prevent, or avoid adverse environmental or social impacts.

As discussed in Section 2.3, the project proponent has voluntarily committed to implement some of the BMPs as well as many standard operating practices commonly used in the Uinta Basin to reduce the potential environmental impacts of the proposed natural gas development. For the GDBR, selected BMPs and improved standard operating practices specific to the project area were developed and evaluated that would mitigate potential impacts resulting from QEP's operations. These measures have been incorporated into the Proposed Action and the No Action alternatives.

The BLM considered an alternative that would require QEP, as a condition of approving the Proposed Action, to implement all of the additional BMPs listed in the national policy guidance and those referenced on the BLM national website (http://www.blm.gov/bmp) to mitigate potential impacts to surface and subsurface resources. BLM considered whether to apply all listed BMPs to all APDs and rights-of-way sought under the Proposed Action.

Per instructions in WO IM 2007-021, the VFO will incorporate appropriate environmental BMPS into proposed APDs, sundry notices, and associated on- and off-lease rights-of-way approvals after appropriate environmental review. Environmental BMPs to be considered in nearly all circumstances include the following::

- Interim reclamation of well locations and access roads soon after the well is put into production;
- Painting of all new facilities a color which best allows the facility to blend with the background, typically a vegetated background;
- Design and construction of all new roads as to safe and appropriate standard, "no higher than necessary" to accommodate their intended use; and
- Final reclamation recontouring of all disturbed areas, including access roads, to the original contour or a contour which blends with the surrounding topography.

Other BMPs are more suitable for Field Office consideration on a case-by-case basis depending on their effectiveness, the balancing of increased operating costs vs. the benefit to the public and resource values, the availability of less restrictive mitigation alternatives, and other site specific factors. Examples of typical case-by-case BMPs include, but are not limited to the following

- Installation of raptor perch avoidance;
- Burying of distribution power lines and/or flow lines in or adjacent to access roads;
- Centralizing production facilities;
- Submersible pumps;

- Belowground well heads;
- Drilling multiple wells from a single pad;
- Wildlife monitoring;
- Seasonal restriction of public vehicle access;
- Avoiding placement of production facilities on hilltops and ridgelines;
- Screening facilities from view;
- Bioremediation of oil field wastes and spills; and
- Use of common utility or right-of-way corridors.

In addition to these national BMPs, the Vernal Field Office of the BLM, operators in the Uinta Basin and Uintah County officials are cooperatively developing a comprehensive list of improved standard operating practices and additional BMPs specific to oil and gas operations in the Uinta Basin. The objective of this cooperative effort is to apply those on individual wells in a case-by-case basis to demonstrate the effectiveness in the field and to facilitate their application to future operations in the Uinta Basin.

Based on preliminary data from over 50 years of oil and gas operations in the Uinta Basin, the final list is expected to include more than one hundred measures that could be considered and evaluated on a case-by-case basis.

Evaluation of these site-specific BMPs and improved standard operating practices requires evaluation during the BLM-mandated onsite reviews prior to approval on individual APDs. That review is currently part of normal BLM permitting procedures; thus, this document does not include evaluation of site-specific BMPs. BMPs would be applied as appropriate under the Proposed Action or No Action alternative. Therefore, a BMP alternative is actually part of the Proposed Action and No Action alternatives. The VFO does not believe the remaining impacts from the Proposed Action necessitate application of all nationally identified BMPs as a separate alternative.

2.4.7 Phased Development

A phased development alternative was suggested by EPA in their comments on the Draft EIS. It is unclear how this alternative would reduce impacts. The 10-year developmental phase of the GDBR project is a type of phased development. As improved drilling techniques would become available over the 10-year period, QEP would apply these techniques if enhanced recovery of the reserves would occur and the new methods would be economically feasible. However, it appears that the EPA-recommended phased development would restrict exploration and development in distant areas until all development within a given area would be complete. As a result, the phased development scenario would deny the operator the opportunity to expand far enough out from existing development to drill exploratory type of wells. These exploratory wells are needed to determine the extent, quantity, and quality of oil and gas potential reserves at locations distant from existing development. The exploratory drilling may indeed lessen overall impacts if it is found that the exploratory wells would not have the desired economic potential. In a phased development scenario, the traffic would tend to be more concentrated in distinct areas thereby increasing traffic impacts on the roads in the vicinity of the construction and development. For these reasons, this alternative was not analyzed in detail.

2.4.8 Minimum Setback Distances

This alternative was also suggested by EPA in their comment letter on the draft EIS. It is unclear how this alternative would reduce impacts. Minimum setback distances are part of the Proposed Action. Setbacks are already incorporated into the Proposed Action. Regulations at 43 CFR 3101.1-2 dictate that facilities can be moved 200 meters to reduce or avoid any impacts. The mitigation and applicant committed measures take into account many of the suggested setback distances, both in time and space. The well pad and access road locations in this document are conceptual, so that the need for setbacks will be identified and analyzed through additional NEPA documentation on a site-specific basis during the review phase of the specific project Application. As stated on page 4-3 of the DEIS, "Executive Order 11988 requires federal agencies to make decisions in a manner that promotes avoidance of adverse impacts and reduces the risk of property loss and human safety due to floodplain development/modification, and preserves the natural and beneficial values of floodplains. Floodplain development/modification is allowed only after there are no other feasible alternatives." Since the minimum setback distances alternative is incorporated into the Proposed Action so there is no need to address minimum setbacks as a separate alternative and it was not analyzed further.

Table 2.6. Comparison of Alternatives Impacts and descriptions

Potential Impact	Proposed Action	No Action
Number of Wells	1,020 gas wells 219 oil wells	177 gas wells 32 oil wells
Number of Well Pads	891	187
Access Roads	170 miles	40 miles
Pipelines/flowlines	235 miles	40 miles
Powerlines	31 miles	0
Long-term Surface Disturbance during Development	4,561 acres (5% of GDBR)	888 (1% of GDBR)
Estimated Natural Gas Extraction (life of project)	615.2 billion cubic feet	106.8 billion cubic feet
Estimated Oil Extraction (life of project)	9.52 million barrels	1.44 million barrels
Effects on surface water	Sediment loading to White and Green Rivers were predicted to be a maximum of 2,375 tons/yr, less than a 0.03% increase of the existing sediment loading in both	Sediment loading to White and Green Rivers were predicted to be a maximum of 705 tons/yr, less than a 0.01% increase of the existing sediment loading in both rivers.
Effects on ground water	Slight chance of groundwater contamination from spills, but BMPs (well pad and road construction techniques and drill pit containment) and SPCC plans would reduce potential.	Same as Proposed Action but smaller likelihood because of only 210 wells.
Effects on air quality during construction	Dust generated during construction of pads and roads and drilling wells would result in localized PM_{10} effects near construction that would be 30 to 45% of the NAAQS.	Same as Proposed Action near each individual facility and road. However, effects would occur at 210 locations rather than the 1,239 locations of the Proposed Action.

Potential Impact	Proposed Action	No Action
Effects on air quality during operations	For the life of the project, PM_{10}, NO_2, and CO ambient air concentrations predicted to be 23, 52, and 50%, respectively, of NAAQS. NO_2 and PM_{10} predicted to be 82 and 70% of PSD Class II increment. HAP ambient concentrations predicted to be less than 1% of Chronic Inhalation Exposure and Reference Exposure Levels except formaldehyde, which is predicted to be 5-10% of standard.	PM_{10}, NO_2, and CO ambient air concentrations predicted to be 5, 10, and 8%, respectively, of NAAQS because project emissions would be about 20% of Proposed Action. NO_2 and PM_{10} predicted to be 16 and 14% of PSD Class II increment.
Effects to air quality and air quality related values (AQRV) at Class I areas	Ambient pollutant concentrations predicted to be less than 0.1% of Class I increments for the life of the project at the following Class I areas: Arches NP, Canyonlands NP, Capitol Reef NP, Black Canyon of the Gunnison NP, Maroon Bells-Snowmass NP, Flat Tops WA, Eagles Nest WA, Mt. Zirkle WA, and Rawah WA. Maximum visibility effects predicted to be less than 20% of the "just noticeable change" threshold of 1.0 deciview. Nitrogen deposition value predicted to be less than 1% of threshold of 3.0 kg/ha/yr.	Insignificant effects that would be less than insignificant effects described for Proposed Action because project emissions would be 80% less than Proposed Action.
Effects to erodible soils	406 new well pads on soils rated with a severe erosion potential, 345 on moderate, 142 on slight.	76 new well pads on soils rated with a severe erosion potential, 95 on moderate, 39 on slight.
Soil Loss	Soil loss estimated to range from 602 to 2,375 tons/year during construction period. Estimated to stabilize at 1,966 tons/year after construction. Soil loss activities in distinct watersheds within GDBR would range from 0.2 to 2.5% increase over the naturally occurring rates. Subsequent sedimentation loading to both the Green and White Rivers is predicted to increase by only 0.03 percent.	Soil loss estimated to range from 308 to 705 tons/year during construction period. Estimated to stabilize at 308 tons/year after construction. Soil loss activities in distinct watersheds within GDBR would range from 0.0 to 1.9% increase over the naturally occurring rates. Subsequent sedimentation loading to both the Green and White Rivers is predicted to increase by only 0.01 percent.
Loss of Vegetation	4,561acres removed during construction. Losses would range from 1.8 to 5.8% of the available vegetation type within GDBR. Although interim reclamation would be attempted after a well would be completed, reclamation may take from years to decades depending on the species. Overall, the action is not likely to lead to the need to list a species.	888 acres removed during construction. Losses would range from 0.6 to 0.8% of the available vegetation type within GDBR. Although interim reclamation would be attempted after a well would be completed, reclamation may take from years to decades depending on the species. Overall, the action is not likely to lead to the need to list a species.

Potential Impact	Proposed Action	No Action
Effects on Special Status Vegetation Species	Development of 17 wells and roads could occur within areas of known occurrence of horseshoe milkvetch, a former candidate species but removed from the Candidate List in September 2006. Site specific preconstruction surveys would be conducted to avoid the destruction of plants. Weed control would occur to prevent invasion into potential or occupied habitats. Overall, the action is not likely to lead to the need to list the species. Potential habitat of the Uinta Basin hookless cactus is present in the southern and west portions of the GDBR in the Uinta Geological formation. Based on the anticipated effectiveness of the mitigating measures BLM finds that the Proposed Action "***may affect, is not likely to adversely affect***" the Uinta Basin hookless cactus.	1 well could occur within areas of known occurrence of horseshoe milkvetch. Site specific preconstruction surveys would be conducted to avoid the destruction of plants. Weed control would occur to prevent invasion into potential or occupied habitats. Overall, the action is not likely to lead to the need to list the species.
Loss of Wildlife Habitat	No BLM-identified antelope or mule deer critical winter habitat within the GDBR would be disturbed by new facilities. 43 new wells and associated access roads would be constructed within raptor guideline buffers. Construction too close to nests could cause raptors to avoid the area. Overall, the action is not likely to lead to the need to list a species.	No BLM-identified antelope or mule deer critical winter habitat within the GDBR would be disturbed by new facilities. 4 new wells and associated access roads would be constructed within raptor guideline buffers. Construction too close to nests could cause raptors to avoid the area. Overall, the action is not likely to lead to the need to list a species.
Effects on Special Status Wildlife Species	New facilities would result in disturbance of up to 16 acres of about 16,000 acres of prairie dog colonies within GDBR. Proposed Action would be consistent with habitat management objectives of maintaining minimum 10,000 acres of prairie dog colonies for the Coyote Basin Primary Management Zone (PMZ). Overall, the action is not likely to lead to the need to list a species. 134 ferruginous hawk and golden eagle nests have been documented in GDBR. High likelihood of impacting some nests, but overall abundance of nests should result in small overall effect. Overall, the action is not likely to lead to the need to list a species.	New facilities would result in disturbance up to 10 acres of about 16,000 acres of prairie dog colonies within GDBR. This disturbance would be consistent with habitat management objectives of maintaining minimum 10,000 acres of prairie dog colonies for the Coyote Basin PMZ. Overall, the action is not likely to lead to the need to list a species. 134 ferruginous hawk and golden eagle nests have been documented in GDBR. Lower likelihood than of the Proposed Action of impacting some nests, but overall abundance of nests should result in small overall effect. Overall, the action is not likely to lead to the need to list a species. Development of facilities would result in 10 acre disturbance of

Potential Impact	Proposed Action	No Action
	Development of facilities would result in 19 acres of disturbance in known sage grouse leks. Grouse could abandon these leks if construction would occur from March 1 to June 15 during the breeding season. However, construction activities would not be allowed during the breeding season so no effects would occur. Overall, the action is not likely to lead to the need to list a species. Based on the potential loss of prey species and loss of habitat, the Proposed Action "***may affect but not likely to adversely affect***" the bald eagle. Based on the removal of water from the Green River (i.e., water depletion) for construction and drilling operations, the Proposed Action "***may affect, is likely to adversely affect***" the endangered Colorado pikeminnow, humpback chub, bonytail, and razorback sucker.	known sage grouse leks. Grouse could abandon these leks if construction would occur from March 1 to June 15 during the breeding season. Overall, the action is not likely to lead to the need to list a species.
Effects to cultural resources	Based on past data, 154 to 462 sites could occur in GDBR. Perhaps 40 percent may be eligible to the NRHP. Seven to 22 new sites could be uncovered during the earth-moving activities. Pre-construction cultural surveys would reduce potential impacts but likelihood exists that some sites could be inadvertently destroyed. Since road network already exists, potential for vandalism should not increase.	Surface disturbance would be approximately 12 percent of the Proposed Action total. Therefore, 1 to 3 new sites could be discovered during surveys or uncovered during earth-moving activities. With less wells, likelihood of inadvertently destroying sites would be less. Potential for vandalism would be similar to Proposed Action because of existing road network.
Effects to paleontological resources	Fossil-bearing geological formations extend into GDBR. Adverse effects (including destruction) would be minimized by paleontological surveys during APD process. Earth-moving activities would immediately stop if fossils would be discovered and the site is evaluated by BLM and State paleontologists and a decision is made whether to avoid the site.	Same as Proposed Action but likelihood of discovering sites during surveys or uncovering during construction would be much less because surface disturbance would only be 12 percent of Proposed Action.
Effects to land use	Continued use of lands within GDBR for oil and gas development. Minor loss of AUMs described in Rangeland Management. No changes in permitted use is anticipated as	Change of land use on State and private leases would be identical to Proposed Action. Overall disturbance and change of land use would be 12 percent of the Proposed Action. No

Potential Impact	Proposed Action		No Action	
	being necessary.		changes in permitted use is anticipated as being necessary.	
Effects to transportation	Average Annual Daily Traffic would increase by 3.5% during 10-year construction phase and 1.4% during operations. Accident potential would increase by approximately the same percentage especially at intersections within GDBR along HW 45.		Average Annual Daily Traffic would increase by 3.5% during 2- to 3-year construction phase and 1.0% during operations. Accident potential would increase by same percentage especially at intersections with HW 45.	
Effects to rangeland management	Long-term loss of 347 AUMs, a 3% decrease in the total preference of the affected allotments. Changes in the grazing permits are not anticipated. AUM losses within each allotment would be as follows:		Long loss of 69 AUMs, a less than 1% decrease. Changes in the grazing permits are not anticipated. AUM Losses within each allotment would be as follows:	
	Allotment	AUM Long-term loss	Allotment	AUM Long-term loss
	Antelope Draw	79 (2%)	Antelope Draw	32 (2%)
	Badlands	3 (2%)	Badlands	2 (1%)
	Baeser Wash	20 (4%)	Baeser Wash	1 (<1%)
	Bohemian Bottoms	19 (5%)	Bohemian Bottoms	3 (1%)
	Bonanza	0	Bonanza	0
	Cocklebur	<1 (1%)	Cocklebur	0
	Horned Toad	84 (5%)	Horned Toad	9 (1%)
	Ouray Valley	<1 (1%)	Ouray Valley	<1 (<1%)
	Pelican Lake	6 (4%)	Pelican Lake	0
	Powder Wash	5 (4%)	Powder Wash	1 (1%)
	Stateline	21 (4%)	Stateline	6 (1%)
	Walker Hollow	17 (4%)	Walker Hollow	0
	West Deadman	91 (5)	West Deadman	14 (1%)

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