Multi-Well Pad Operations for Shale Gas Development

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Summary

This report is a brief investigation of energy industry experience with multi-well pads for natural gas developments in North America. The main objective was to explain the benefits of multi-well pads to elements of the Sierra Club to offer energy industry perspective on potential benefit in reducing general environmental impact (wildlife, neighbors and soil, air and water impact). Secondary objectives were to detail some of the impacts on safety and the general economics of pad developments as compared to single well operations. <u>This document is a general report from an energy industry point of view on perceived improvements of multi-well pad operations over individual well sites and is not in any way a detailed environmental study</u>. Data for the report is from published reports and the range of investigation was limited to land based operations in North America. Although the intent of the study is aimed at shale gas development, other multi-well pad operations, specifically Pinedale, Jonah, West Tavaputs, and some Piceance operations have been used to gain experiences in environmentally sensitive areas.

Overall environmental impact from an energy industry perspective was perceived as generally positive in the short term and very positive in the long term. Focus on environmental impact and the ability to get well development permits was the main driver for most of the pad developments in this study. Specifics on environmental benefits for approximately equal number of wells in a unit area of development comparing single well pads and multi-well pads included:

Advantages

1. In brief examinations of the results of state sponsored wildlife studies, the impact of multi-well pad operations appeared to have less impact on habitat, migration, nesting and range of wildlife than with developments of numerous single well pads. This point is not suggested as a final conclusion and each area will require sufficient environmental study to make sure the impact is minimal and within permissible limits.
2. In muskeg areas in Canada, small pad sites prepared for year- around operations resulted in less impact on larger areas. Pads as small as 10 acres for 16 wells covered over 1000 acres of resource development.
3. Reduction of total acreage-per-well of permanent pad fell from an average of 2 to 5 acres per well for single well developments to about ½ acre or less per well in the latest generation of pad development.
4. Movable rigs (without tear-downs) on these small pads sharply reduces total time of developments, minimizes need to truck in large cranes and large crews for rig moves, and minimizes spills created when fluid supply lines are dismantled and reassembled.

5. Reduction in road building of roughly 40% to 50% is common. A single 20 acre development pad (where more than 50% of the initial land in the pad is reclaimable to prior state at the end of active development) could develop 640 acres to over 1000 acres with a single road.
6. A 70% to 80% reduction in length of surface or buried gathering lines (lines from wells to processing tanks) is possible on a pad and the lines can be more easily inspected. There are added benefits from eliminating stream and road crossing, as well as reduction in trenching and presence of surface line.
7. A single processing facility (on the multi-well pad) and concentration of the equipment allows simplified installation of spill containment berms and leak prevention liners as well as sound and visual impact control.
8. Reduction in truck traffic is roughly 30% to 60%, depending on the type and stage of development. Planned road routing and dust management practices improve dust, traffic and noise control ability.
9. Inspections on wells, tanks, lines and sites are viewable from one location. Added benefits include ability to heat trace lines in a concentrated area to prevent freeze ups that can lead to leaks and repair operations.
10. Ability to use low profile wellheads, tanks and piping is improved on the multi-well pads. Subsurface well heads (concrete cellars) have been installed in some developments, but the cellars create safety problems with confined subsurface work areas and cover weight integrity as well as sharply increasing well expense. Options to reduce the requirements for cellars would generally be very welcome.
11. Ability to concentrate development activities such as drilling, fracturing, workovers and production operations is improved in multi-well pads. This allows use of better spill prevention/containment methods and faster response on emergency operations.
12. Ability to handle produced water, including frac flowback water, is simplified in a multi-well pad operation through proximity of all wellheads to a single treating facility or by using a single flow line out to a large facility. By using centralized water treating operations, produced water is now being commonly reused in many shale fracturing operations in the Marcellus shale of Pennsylvania and West Virginia where Range Resources has pilots reusing 100% of produced fluids. Using these techniques, reliance on deep well disposal can be reduced. Concentrated multi-well pad developments reduce brine water transfer distance (minimizing spill potential). Centralized treating makes possible efficient containment, more constant throughput of separation equipment and use of fit-for-purpose facilities such as filtration, membrane separation of salts and reblending with small amounts of fresh water for water reuse, etc.
13. Concentrating the wells of a development in a small area allows better geologic control of drilling through the upper rock strata, generating knowledge and experience that reduces drilling time, improves cement jobs and monitoring of those cement jobs. Note – potential for a producing or disposal well to contaminate ground water aquifers is generally very small, but if communication is possible, the route of fluid flow is nearly 100% up channels or micro fissures in the cement sheath. Monitoring of potential for leaks is possible through various investigative tools applied through the wellbores. Close spacing of the wells makes this investigation and the trend monitoring of pressures more practical. The risk or potential for leaks from fracturing

processes into ground water is so remote as to be impossible (This will be explained and documented in the body of the report).

14. Horizontal well, multi-well pad operations have a proven track record of reducing drilling days per well (often by 50% or more), reducing the total number of wells, and increasing the recovery of hydrocarbon in place. The reduction in drilling days came about as the result of ability to concentrate on improving the process instead of stopping and having to break down and move the rig every three to five weeks. In some cases, drilling days were reduced from 61 days per well at the start of the project to 15 days at the end for similar wells.
15. Horizontal wells are rapidly replacing vertical wells as the well design of choice for shale and other developments. The environmental advantages of the horizontal well design is that one horizontal well can replace 2 to 10 vertical wells and that wellheads for horizontals can be concentrated in a small area. The horizontal wells are more expensive than the verticals but also produce more gas when staged multiple fracturing is used.
16. Reduction in chemical type and chemical volumes are very common with multi-well pads. As work with the recycled water and well configurations have developed, new methods of eliminating problem chemicals such as biocides with "no-residual" processes using ultra-violet light and chorine dioxide (a free radical process that breaks down after use) are in trials in fracturing fluids used in shales.
17. The slick water fracturing fluids in use in most shale developments usually have four or fewer additives: friction reducer, biocide, scale inhibitor and oxygen scavenger. Friction reducers are a polymer common to food grade products. Biocides are typically gluteraldehydes or quaternary amines common in medical service, swimming pools and disinfectants; newer biocide efforts involve ultraviolet light (UVL) or dilute chlorine dioxide – a produce that leaves no residuals. Scale inhibitors as often phosphonate materials that adsorb in the formation. Oxygen scavengers, which are common only when using fresh water, remove the oxygen to prevent corrosion in well tubulars. Few other chemicals are used in the shale.[35] More complex fracturing fluids, usually with chemicals similar to home and very light industrial use, are used in non-shale developments.
18. Given the reductions in roads, truck traffic, rig moves, leaks, facility reductions and reduction of the total number of wells, air quality improvement should be attainable in multi-well pad developments. Use of centralized facilities and operation of equipment on natural gas should reduce engine emissions by about 30% over gasoline and 25% over diesel. Additional air quality improvements may be possible through electrification of the multi-well pad and use of water transfer pipelines to reduce truck traffic. Vapor additions can usually be controlled with scrubbers and vapor trapping/recycle technology.

Disadvantages

1. Work time is longer in a single area. These developments may take six months to a year, depending on number of wells and the number of rigs.

2. The single pad is larger for the multi-well pad than the individual pads for single well developments. Ten to forty acres is typical for the development phase, although some of the pad can be reclaimed.
3. Well activity must be coordinated through Simops (simultaneous operations). This requires a manager with Simops experience and will require a significant amount of planning to carry out all activities with high efficiency. The efficiency of pad operations is dependent on how well learnings are incorporated.
4. Well cost on multi-well pads is initially higher, especially for companies that do not have prior experience with multi-well pad developments.
5. Specialty chemicals must be developed to work in recycled brine fluids. Note – these chemicals are just different blends of chemicals in use today.
6. Well design is more involved and more pipe and cement are required to form effective isolation around the wellbore.
7. Horizontal wells require directional drilling services, slightly larger drilling rigs to handle the extra pipe loads and require special operational procedures.

Economic benefits of multi-pad operations are generated through cost savings in many phases of large developments. Cost reductions in the range of 25%+ were seen comparing all-in well costs (total cost from permitting to first hydrocarbon flow) after 5 to 10 wells on average. Drilling and completions costs in this same period were cut in half, while pad and environmental costs increased with stricter regulations imposed by the states involved (Wyoming and Utah). This was a common factor in the multiple projects studied. These cost reductions were for early vs. later wells in multi-well pads. Drilling costs comparing multi-well pad directional wells to single pad vertical wells were about 20 to 30% higher for the early directionally drilled wells, mostly for directional drilling charges, increased casing and extra costs of the larger pads. The learning curve will at least partly offset the increased drilling and completion cost, highlighted by a report of savings of $250,000 in completions because pad wells could be completed in tandem (cementing, fracturing, etc.). A variety of other drivers and learnings produced many economic and engineering benefits:

- Well Spacing
  - Drivers for the multi-well pads were, at least initially, largely environmental. Savings in one area often offset increased costs in others.
  - Each multi-well pad, using 16 to 35+ wells per pad and laid out to minimize equipment movements, replaced ten to thirty smaller drill pads and about 40% to 50% of the service roads and pipelines, reducing the total "footprint" of the project, often by over 50%.
  - Rig moves were cut by as much as 75% in multi-well pads.
- Cycle Time
  - Permitting – in most cases in Pinedale and Piceance, the areas probably would not have been opened to exploration and development without the multi-well pads. In any event, the multi-well pads cut significant time off the permitting and approval process.

- Speed of activity – although thought initially to be slower, the multi-well pads actually cut the total project time in half in some projects in the Pinedale and Piceance areas.
- Rig Efficiencies – Fit-for-purpose rigs and learnings cut the initial drilling time almost in half, from beginning to end, for nearly every project studied.
- Developing Simops (simultaneous operations) was a critical issue in bringing wells to production quickly while other wells on the pad were being drilled, completed, or fractured.
- Twenty-four hour operations had both supporters and detractors. Working 24/7 on a drilling rig made economic sense, but working 24/7 on frac operations required extra equipment in high required-maintenance equipment such as frac pumps, sand transfer equipment and other equipment.

- Facilities
    - Facility design and operation requires consideration of specific project design. Wells are more likely to be brought on en-mass, so larger facilities needed to take advantage of peak rates, will be severely overbuilt as rates decline, unless centralized.
    - Water usage and supply from produced water, fracs water and frac flowback must be managed. Water management and relatively simple reprocessing and reuse eliminated many problems with environmental issues.
    - Multi-well pad operations use fewer, more efficient facilities and more compact gathering systems
- EHS
    - Environmental resistance was present and continues, but communication, education of both side to concerns and options, and working with local groups and government agencies resolved many of the issues.
    - Safety was significantly improved by minimizing rig-up/down frequency and reducing travel.

General overview

Land based multi-well pads have grown in popularity with the energy industry in North America and are increasingly considered for wells in unconventional reservoirs such as stacked and highly layered pays found in the Pinedale anticline, Jonah and some formations in the Piceance Basin. Other examples of multi-well pads are found in gas and oil producing shale developments common in the Barnett shale of the Fort Worth Basin and the Marcellus shale in the eastern US. The practice of grouping wells tightly on multi-well pads in these areas has been driven by environmental, economic and practical factors including pressures to reduce footprint and traffic as well as accepted reserve calculations that qualify immediate offset wells as PUDs (proved, undeveloped). Drilling and completion costs of directional wells from pads, are usually higher initially from directional costs that may range to $500,000 per well, but costs were proven to drop in nearly all cases with accelerated learning in all phases of well construction costs and pad-friendly operations such as closed-loop drilling, presetting shallow casing, and factory-type well profiles reached with learnings input.

Where conventional learning curves have shown about 25% drilling days reduction within the first ten wells; pad drilled wells are showing 40 to 50% decreases in days after five to six wells. Reasons for faster learnings generation and application are rooted in the larger number of wells drilled in a shorter time and the "permanence" of the multi-well pad, which minimized many of the changes that often slow or confuse learning when rigs, support equipment, geologic settings and people are changing from well to well. Additional learnings acceleration was derived from development and operation of fit-for-purpose rigs and having a consistent set of personnel on the projects. Total development cost savings are realized in accelerated learnings from all stages of well construction as well as where factors of safety, footprint, facilities, pipelines, and environmental issues are considered. Economic evaluation of multi-well pad projects must be based on the entire list of project factors. Not one production company surveyed reported higher late-stage cost on recent multi-well pad operations.

Drilling and completion costs in the Pinedale Anticline, Piceance, West Tavaputs Plateau and a few other multi-well pad areas were often higher if compared directly to vertical wells, but many of these developments were not possible with vertical wells, given the need to use *bottom hole* (not surface) spacings of 5 to 15 acres. Note-this close bottom hole spacing of the wellbores is unusual and these reservoirs are a special case. More conventional well spacing of 40 to 80+ acres is the norm. For comparison, spacing in the Fort Worth Basin Barnett shale is 40 to 80 acres with one to five producing wells and three to ten PUD locations to a pad. The Barnett Shale development demonstrated that multi-well pads were strongly justified over single well pads in shales. In the Barnett, virtually all wells are directionally drilled and have multi-stage fracture treatments. The shale wellbores were fully horizontal with 5 to 16 fracture stages per wellbore, so the analogy from Pinedale to the Barnett shale is not exact, however, savings by grouping the wells and using closed-loop drilling, longer term rig contracts with less mob/demob activities, simultaneous or sequential fracturing and single facilities for grouped wells easily saved 15 to 20%+ percent over single well efforts in the shale.

Production operations costs are also lowered by reducing gathering line lengths (and associated ground disturbance), assuring full facility capacity throughput early in the project and centralized benefits for facilities, power distribution, central compressor, pump sites, produced water processing, lift system operation and well monitoring. The extent to which these services are needed in a project defines the savings for specific multi-well pad operations. Construction costs are also relative to the project and depend heavily on the level of special add-ons such as expensive covered cellars for lowering the profile of wellheads.

There are some higher costs in directionally drilled, multi-well pad developments including: directional drilling costs to hit targets 1500 ft or more away (initially estimated at $500,000 and then sharply reduced by learnings); technology requirements for well-to-formation entry for stimulation and maximum production; cost of longer drilling times and additional steel for longer measured depth wells, collision avoidance modeling and various higher construction costs to tightly group and protect wellheads and other equipment. In general, the multi-well pads are agreed to be most economical when pad construction costs are not exorbitant and directional drilling can be mastered without significant expense.

Critical economic factors (as established from both economic and non-economic examples) include:

- Control the cost of the multi-well pad construction and minimize special, high cost items such as covered cellars for wellheads. Compromises with low profile equipment may be possible.
- Accelerate learning curves that have a proven track record of reducing drilling.
- The ability to move quickly from well-to-well reduces non productive time. Several cases were found of drilling rigs on rails, jack plates or skid plates to drill tightly spaced surface templates. Not having to rig-down and back-up often saved two days or more per well.
- Use of the closed loop drilling system to save mud costs and other fluids and cut waste generation and saved significantly on mud costs ($30,000+per well mud savings).
- Consideration of a smaller, lower cost rig to drill, set surface casing and cement the surface pipe holes ahead of a larger rig (recommend the use of fresh water for these steps). This worked well if the larger rig was far enough behind the shallow rig(s) to allow full pad access without significant Simops and if the larger rig costs were significantly higher than the smaller rig costs.
- Set sufficient surface casing to meet legal requirement for isolating all fresh and near-fresh water sources. If the regulations are unclear, a distance of 200 to 300 feet below the water source formations, cemented completely back to surface is suggested. A pressure test is required and a cement bond log is highly recommended.

Of the six areas of well construction: pad/road construction; gathering/pipeline construction; facilities; drilling; completions; stimulations; and operations: at least four (gathering/pipelines, facilities, stimulation and operations) offer significant initial savings demonstrated by both multi-pad wells in the Pinedale/Piceance areas and in the Barnett Shale. Savings on pads/roads were small or break- even as better roads were required on multi-well pads to withstand the heavier traffic loads. Pre-stimulation completion costs were usually initially higher on multi-well pads because of larger amounts of casing and running/cementing times. Drilling on multi-well pads could be a large savings if directional drilling costs are lowered and learnings captured multi-well pads accelerate the learning curve and delivers reduced drilling days earlier in the development. Fracture stimulation, especially multi-stage fracturing of wells on a multi-well pad should cut the normal single-well fracturing stimulation costs by at least 7% to 10%, a number similar to the savings of fracturing zones in sequence and wells in sequence or at the same time (simultaneously) in shale developments such as the Fort Worth Basin Barnett shale.

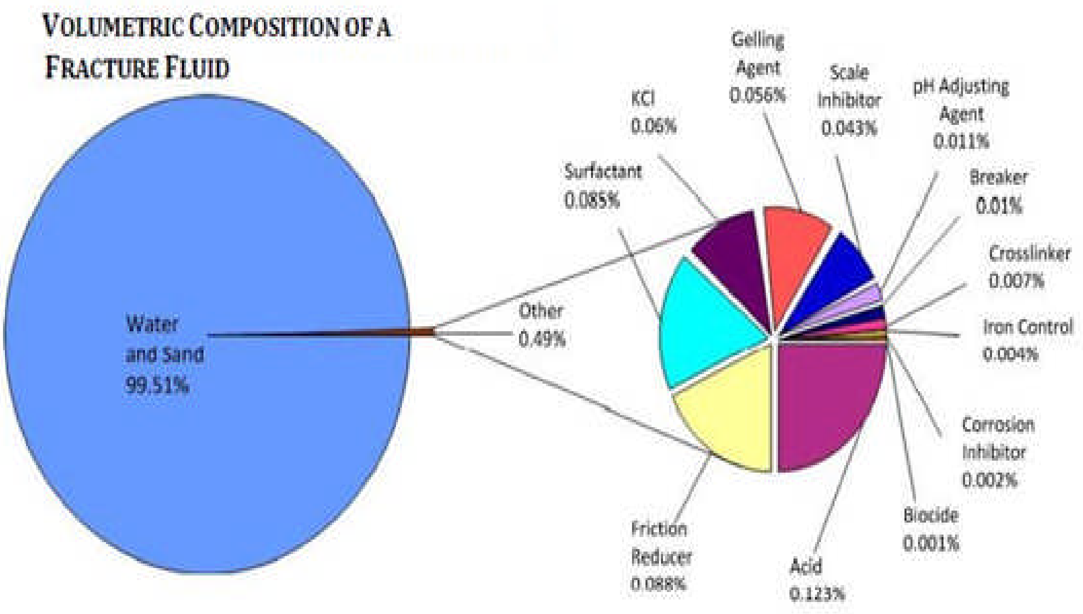
General philosophy for selecting single or multiple well pad developments considers several factors, both dependent and independent, in the choice of multi-well or single well pads. The bottom line for the decision includes HES (Health, Environmental and Safety), learning curve acceleration, Simops activity, ability to reach and develop the reservoirs and local infrastructure.

Handling Produced Water - Water supply, processing and disposal analogues for drilling, completions, fracs and produced water are available from Piceance and Pinedale (Appendix G). These studies showed a progression away from fresh water (both surface supply and water wells) to a mix of produced and processed water with a minimum of make-up fresh water. Fresh water is used for drilling shallow sections and completing these sections to protect ground water supplies.

There have been issues with these waters including learning to control increased salt content from contact of frac water with the saltier water of the shales. To reuse these increased salt loaded fluids may require reblending with fresher brines, osmosis, or evaporation processing. The chemical usage in most fracture fluids usually results in low levels of natural salts, polymers, surfactants, and formation and proppant fines returning in early stages of the backflow. These materials must be reduced to a level that allows reuse.

The level of processing required is dependent on the formation sensitivity. Although mineralogy studies and cores tests will help predict potential sensitivities, only field data will tell if the processing is effective. In the Barnett shale and some other places, both laboratory and field studies have been used to find the effective limits of salt and the necessary additions of chemicals to make a water usable in a specific development.

The breakdown of additives and the following chart of frac additives are from the DOE sponsored Shale Primer[35]. This is a good starting place for identifying the various potential chemical additives in a frac. The amount of additives in a frac is usually about 0.1% to 0.2% by volume for a slick water frac and perhaps 1/2% for a gelled or crosslinked frac.



Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale, 2008

FRACTURING FLUID ADDITIVES, MAIN COMPOUNDS, AND COMMON USES.			
Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color
Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.			

In the Barnett shale, much of the water transport to and from rigs and fracs has been handled by trucks; however, very large fracs common in multistage fracturing may require hundreds of water transport truck trips, increasing noise, air quality problems, dust, traffic and road wear. For multi-well pad operations, water district-type pipelines of HDPE plastic or equivalent can offer water transport between pads and a single large water processing plant that benefits from economy of scale.

Shale Well Operations from Pads

A large number of Barnett shale wells are completed from multi-well pads. The initial drivers have been in urban areas and environmental risk areas and where production improvements from simultaneous fracturing were shown to be a major benefit[23]. The typical well counts on a pad in the Barnett is in the range of three to eight, but examples of higher density in urban areas are well known. The savings over single wells are easier to pinpoint in the Barnett since horizontal wells with multi-stage fracs are standard regardless of the well grouping. The 15 to 20%+/- cost advantages to wells in the more dense pads revolve around common roads, power lines, gathering lines and fluid storage (together ~5%), closed-loop drilling (~10%) and fracs (~5%+). The efficiency of the operator, presence or absence of drilling and production challenges and the time and place of the drilling creates large variances in the cost savings numbers. Best-in-class to middle of the pack all-in well costs in Parker County, TX, Barnett shale wells with similar wellbore length and same number of fracs could easily vary from $2.2mm to $3.3mm. Performance of those wells varied widely as well, with shale quality in an area being a much larger factor on production rate and recovery than total well cost.

Fracturing Comments

Hydraulic fracturing or fracing is a well known and established stimulation necessary to increase production from low permeability wells. Over the past sixty years of hydraulic fracture experience, industry estimates place the number of fracturing jobs done worldwide at over one million. Fracturing enables roughly 60% to 80% of the gas production in North America and virtually all of the expected 2000 TCF of gas reserves in shales. From recent literature and specialist surveys, there has been no documented case of hydraulic fracturing stimulation breaching into ground water supplies. When leaks of producing well fluids into a fresh or near fresh water aquifer have occurred, the problem usually has been found to be poor cement sheath seal – a problem that can avoided by commonly known cement design, execution and monitoring steps. A few problems have also occurred during drilling where well control was lost when the upper hole had not been sealed with casing and a full cement sheath over the fresh water zones. These events are rare and overwhelmingly preventable.

Fracturing fluids, as detailed in the Shale Primer[35], show chemical compositions that are the same or generically similar to products used in home, swimming pools, food processing and medical practice. Toxic chemicals in fracs are very rare and usually limited to small amounts of biocide. When toxic chemicals from outside the range of normal frac additives are found, a check of local disposal wells (licensed and unlicensed) should be conducted. The toxic and cancer causing chemicals claimed ion recent literature to be from fracs are not fracturing additives.

Fracture height growth is difficult to achieve because of the leakoff of hydraulic fracture fluid into the pores of permeable rock. As the fracture grows in area, this leakoff soon equals the maximum pump rate and the fracture stops growing. This leakoff self-limits the height of hydraulic fractures. Downhole video camera pictures of fractures forming at the wellbore and being stopped by even thin formation barriers such as ductile shales have been recorded.

Technology to track fracture growth, both aerially and vertically have been applied on over a thousand wells during the fracturing process. Microseismic evaluation, tilt meters, temperature logs, chemical fluid tracers, and produced fluid analysis are used routinely to determine where fractures form and how far they advance in the formation.

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Appendix A Questar Project Description

Questar in the Pinedale Anticline, Wyoming

The Pinedale Anticline

The Pinedale area is an overpressurized, low permeability "tight" gas sand play, with production depths from 8,000 to 14,500 feet. Braided streams, with channels 10 to 20 feet deep and hundreds of feet wide, deposited approximately 5,000 feet of fluvial clastic sedimentary rocks in a broad alluvial plain. This led to the formation of lenticular reservoirs of tight gas sands (think an array of massive potato chips).

These reservoirs lie in the Lance and Mesaverde Group – Ericson Formation of the Greater Green River Basin in the Pinedale area. The Jonah Field, adjacent to the Pinedale Anticline, also produces gas from similar tight gas sands.

The very low rock permeability within the reservoir requires that additional techniques (hydraulic fracturing) be used to open artificial (induced) fractures to facilitate the movement of the natural gas to the production wells. In addition, the lenticular nature of the reservoir requires that multiple wells be drilled to penetrate as many of the lenses (potato chips) as possible.

History

The California Company drilled the first test well on the Pinedale Anticline in 1939. However, gas production was too low and the nearest pipeline was too far away to warrant further development. A number of other attempts were made in the 1940s and 1950s, and while the results were encouraging, the low flow of gas from the "tight" sands prevented economic development.

With the advent of new fracturing techniques in the 1990s, it became possible for the permeability of these reservoirs to be increased, thus permitting production of the natural gas. In addition, technological advances in directional drilling permitted multiple wells (up to 16) to be drilled from a single pad, thus reducing some costs and minimizing the environmental impact of development (Fig. 1).

The Pinedale and Jonah fields are considered among the most significant new natural gas resources in the U.S., and it has been estimated that the reserves from the Pinedale Anticline alone could exceed 20 trillion cubic feet.

Questar's Operations

Questar, an independent oil and gas company, drilled its first natural gas well in 1922. In 2004, its total proven reserves were 1,434 billion cubic feet of gas equivalent (bcfe) for a 13.9 years production life. With a total production of 103 bcfe in 2004, the company's total assets were $3.646 billion and an annual net income of $229 million.

Questar's wells in the Pinedale Anticline are drilled to depths between 8,000 and 18,000 feet. The company has proven gas reserves in the Pinedale Anticline of 738 bcfe, and it is reported that the discovery and development costs are approximately $0.90 per thousand per cubic feet (mcf) of produced gas. In 2004, Questar had 470 locations based on 20-acre spacing, with depths between 9,500 and 14,500 feet.

Environmental Issues

Extraordinary efforts are being made by all major companies drilling in the Pinedale Anticline and the Jonah Field to minimize the environmental impact of the drilling and production operations. While the latest state-of-the-art technology is being utilized, and unprecedented efforts are underway to communicate with all of the concerned constituencies, there remains considerable resistance to the development in the area.

Appendix B

Lessons Learned from the Pinedale Anticline

Prill Mecham, Pinedale BLM
Robin Smith, Mountaintop Consulting

Peter Aengst, The Wilderness Society

Notes:

Prill Mecham, Pinedale BLM:

Notes submitted by Ms. Mecham prior to conference: The Pinedale Anticline Oil & Gas Exploration & Development Project EIS was completed in July of 2000. At the time of the signing of the Record of Decision (ROD), only 14 wells had been drilled in the roughly 197,000 acre project area. Following the signing of this ROD, new issues regarding wildlife arose, new management guidance arose, data gaps were discovered, management prescription modifications were identified and new mitigating technologies were discovered. Additionally, the subsurface geology was virtually unknown, resulting in uncertainty regarding where the development would take place and how dense it would be.

The high level of uncertainty associated with this project required flexibility on the part of BLM in order to responsively manage the development through time and potentially changing impacts. Adaptive Management (AM) was viewed as the vehicle to provide this flexibility. It was critical to this effort that BLM gain acceptance of the project by governmental agencies (federal, state, county and town), by interest groups such as livestock operators, oil & gas operators and the environmental community, and by adjacent landowners and the public at large. Including the AM process as an integral part of the ROD resulted in Wyoming BLM receiving EPA's highest rating on this EIS and also resulted in no appeals filed which were based on resource or analysis issues.

The AM process was stopped cold by a lawsuit in early 2001 based upon two points: 1) BLM does not have the authority to implement AM because it has not gone through the rule-making process, and 2) inclusion of non-government members on Working Group/Task Groups is a violation of the Federal Advisory Committees Act (FACA). Although the judge dismissed the lawsuit as moot, it was agreed that the Working Group did violate FACA. The AM process has been placed on hold for three years waiting for the chartering and nomination processes under FACA to be completed. The committee was finally approved on May 4, 2004.

Many lessons have been learned from this experience. Advisory groups are one way to involve the public in AM. The traditional NEPA process is another way. There are positive and negative aspects to implementing both AM approaches to resource management decisions. Managers need both approaches in their tool box.

Notes from Ms. Mecham's talk: The Pinedale Anticline Natural Gas Field (PAPA) is located in west-central Wyoming. PAPA is nestled in between the Wyoming and Gros Ventre ranges. It's a very rural area- no stoplights in the entire county. Pinedale is a major gateway to the Wind River Mountains, the Tetons, and Yellowstone. Tourism is very important to the area, and the residents value the clean air, etc.

The PAPA begins at outer limits of Pinedale. A Prominent feature in the area is the Mesa. It's very important for its wildlife, scenic value, and solitude. There are intense protective sentiments towards the Mesa. How does AM fit in? An EIS is an estimate of impacts and an estimate of mitigation effectiveness, but sometimes EISs must be based on old data, as there is no recent monitoring data from which to pull.

Why the need for adaptive management?

-new issues arise

-new guidance is issued

-information comes in which allows us to fill data gaps

-new technologies

One resource estimated to sustain impacts from developing the PAPA is wildlife; the antelope and mule deer. The PAPA area contains critical winter range and has the 2nd longest large mammal migrations. Pronghorn migration routes weren't well enough understood at the time of the EIS, so the EIS didn't deal in detail with the issue. This is a new issue, appropriate for AM.

Also, there are few remaining sage grouse habitats. Many different groups and agencies are working on ways of avoiding having to list the birds as endangered. Therefore, data gaps are being filled, making AM appropriate.

The area contains one of the last intact Oregon Trail segments- visibility analysis found no areas where production equipment could be screened from view. The Plan would need management prescription modifications, making AM appropriate.

Regarding air quality, the PAPA Area is no more than 20 air-miles from the nation's largest Class-I wilderness, the Bridger Wilderness, as well as other designated Wilderness Areas. The wind flows (of course) go from PAPA to Class I wilderness. Deposition on air quality goes to the Forest Service. Air quality impacts might be mitigated based on new technologies (mitigating), making AM appropriate.

Also, this is a brand new area. BLM is not only faced with uncertainty on impacts, but uncertainty in action. We (BLM) knew nothing of the subsurface geology, and estimates varied considerably. 300-3000 wells were estimated to be necessary. No one knew where the development was to take place. Scientific uncertainty is another factor making AM appropriate.

Fracting in the area was brand new. Some drill techniques were thought to be OK but were untried, so operators were unsure if mitigation techniques would be effective.

Monitoring was absolutely NECESSARY. So we saw adaptive management as a critically important tool. The monitoring and readjustment of the land management would be an annual iterative process. What stipulations should we include? The monitoring would help to modifying next year's mitigation plans.

BLM needed to get buy in from local and regulatory constituents. The first reaction was "absolutely not!" from area residents. But the residents themselves are a resource. The very character of the area was about to be threatened.

Innovative solutions include authorizing the level of impacts, rather than a particular number of wells. This "level of impact" authorization would include the well pads and the amount of surface impacts.

BLM, with the help of dedicated stakeholders, developed a 3-D alternate matrix, which included 9 alternatives. Development of the matrix required hundreds of hours of public involvement meetings. For the first time, in BLM Wyoming history, EPA gave the highest rating, "no concerns", to the EIS, and no appeals filed based on resource or analysis issues.

The plan basically implemented an adaptive management process, to continue throughout the life of the field, and adapt it if necessary. The plan would feed monitoring results back into decision-making process.

The process was based on science and technological problems that the development would encounter. How to best monitor based on science/technological issues? Some people on the committee, formed to monitor the area may not have been educated on the scientific/technical issues, but the plan provided the group with an opportunity to educate its members on the scientific and technical issues that would be encountered in the development of the PAPA area.

Working Group Model: A Working group was to monitor the decisions that were in the record and monitor the results based on next year's drilling plan, and then make *recommendations* to BLM.

Decision Model: BLM takes recommendations from working groups, evaluates the monitoring data and recommendations, makes changes as necessary, and implements as it sees fit. BLM retains decision-making authority.

The Yates Petroleum lawsuit claimed that AM hasn't gone through the rulemaking process, and it is a FACA violation to include the public when a government agency establishes or utilizes a citizens advisory group without chartering it under FACA.

Post-lawsuit, the FACA group took almost 3 years to charter, and just was chartered last week. During these 3 years, AM has not been taking place. Monitoring has taken place but nothing has been done with the data.

The process was beneficial, especially for an agency like BLM. Here, there was mutual trust developed, where there were long histories of the citizens and local residents being at odds with BLM. Everyone understood each others' values and perceptions, even if they didn't agree. This led to *civil* discourse, which was critical to making headway. Many had fought with each other for years! But all needed to figure out how to work together to protect the land they all cherish. If they find the common ground themselves, without BLM telling them where they should be agreeing, they believe in it and support it.

The group developed an ownership of BLM decision-making. Even if they didn't like BLM's decisions, they understood why the agency made them and were less likely to appeal or sue.

Robin Smith, Mountain Top Consulting:

Notes submitted by Mr. Smith prior to conference: 1) AM must be regional in scope, because ecological processes and species can only be managed in large ecosystems.

As a first step, managers must set goals and objectives. As a key component, these objectives, or statements of desired future conditions, must be regional in scope and incorporate economic and social objectives as well as ecological ones. Wildlife monitoring data gathered at Jonah Field provides an example. This data, when analyzed by different individuals, gives two very different answers. Some focus on the decrease in attendance at a single lek near moderate development activity and conclude that the presence of that activity has resulted in an impact to sage grouse viability. The reaction to this conclusion is that more mitigation is needed to protect sage grouse. Analysis of the entire data set and comparison to statewide sage grouse trends yields a much different view when considered from a regional scope with population survival as the goal.

2) AM must reconcile conservation biology with sustainable development.
Industries understand the importance of data gathering and analysis. Companies that engage in the search for oil and gas reserves rely heavily on data. They constantly "look back" and improve technologies and methodologies, so that decisions can be made on actual experience, not supposition. If they didn't, they would not survive in the highly competitive arena in which they operate.

BLM has typically managed through environmental policy that has been formulated in response to unmonitored experience. BLM's role in managing ecosystems and habitat is far different than that of users of public lands. The activity of these "customers" more closely resembles cultivation, and is focused in relatively small parcels. BLM's management goals must be broader in scope, and include incorporate economic and social objectives.

3) AM must promote experimentation and learning to a high priority.
BLM application of AM in the PAPA is designed to determine the effectiveness of its mitigation decisions. BLM should not use the NEPA process as its "back door solution" for providing data that supports its current mitigation policies. Goals and objectives of AM, and ultimately BLM's mitigation decisions, should be performance based. The objectives should include the ability to test the basis for mitigation in controlled experiments. Winter drilling on Mesa is a good example of this.

4) BLM must share in the cost of collecting data.

BLM has not adequately addressed the cost, personnel, and future commitment needs of a successful AM process. BLM should not continue to shift the entire cost burden of AM to operators, but should participate on an equal basis.

5) Solutions.

Successful implementation of AM will require a shift in agency philosophy from one of maintaining systems in a single optimal state to one of maintaining optimal management capacity. This will require well-defined objectives that consider economic and social objectives as well as ecological ones. Crucial to successful implementation is a willingness to test management decisions by experimentation, and flexibility in management decisions. Addressing personnel needs and budget requirements is also a key to successful implementation of AM.

<u>Notes from Mr. Smith's talk</u>: There are several lessons to be applied, not necessarily lessons learned from any one experience. Adaptive Management needs to be regional in scope, and study ecological processes. In the Record of Decision (ROD) for the PAPA- EIS you should develop resource monitoring plans for different resources. And modify mitigation techniques as appropriate. A regional scale would be for the Jonah field. The Jonah Field doesn't have in its NEPA analysis anything about AM, but there is a wildlife monitoring plan, to monitor sage grouse leks. One lek can drop sharply over years, but if you monitor regionally, you see that the situation roughly parallels the state.

AM must reconcile conservation biology with sustainable development. BLM's role and goals in managing lands are maintaining a certain level of resources and the health of those resources. Industry's role and goals are more consumptive in nature. BLM needs to reconcile those uses.

AM must promote experimentation and learning as a high priority. Currently a high priority is not placed on changing techniques unless there are really bad impacts. In the past, where there's crucial winter range, there's no development during 6 months out of the year. Questar has proposed being allowed to drill through the winter and to study the effects of that, because the overall duration and disturbance would be shorter. With activity year-round, the surface disturbance is smaller, the number of pads is reduced by one-half, the duration of drilling is shorter, but the mitigation cost is higher. By studying mule deer movements during the winter, we can see how they are affected by winter drilling, if at all. BLM granted Questar a one-year exception from the 6-month limits. BLM concluded there was no conclusive adverse impacts to the deer from year-round drilling. There are sixteen well pads from the surface. Most of this took place outside of the AM process.

BLM must share in the cost of collecting and analyzing data. Most plans say that the industry will pay for all adaptive management and monitoring, though BLM contributes three months of employee support for wildlife monitoring. There needs to be somewhat of an allocation of costs. Industry shouldn't' have to bear the entire cost.

The main point is that industry is not opposed to AM. If industry didn't change its techniques based on the past then it wouldn't learn anything. Important in achieving goals and objectives set forth. Don't waste the money spent on mitigation, spend it effectively.

Peter Aengst, the Wilderness Society (Bozeman Montana):

<u>Notes submitted by Mr. Aengst prior to conference</u>: To put this adaptive management project in its proper context one must understand both the values found in the project area and the decision that put this adaptive management effort into action. The Upper Green River Valley – and especially the Pinedale Anticline portion of it – has world class wildlife, scenic, and recreation values. It also has world class natural gas deposits. While the BLM's July 2000 ROD for the Pinedale Anticline project approved the construction of up to 700 new well pads (and 276 miles of roads, 400 miles of pipelines, and construction of compressor stations), this approval was on the condition that the Resource Protection Alternative ("RPA") also be implemented. The RPA has two prongs: 1) restrictions and mitigation measures; and, 2) adoption of a Adaptive Environmental Management ("AEM") planning process.

The AEM had some strengths and did some things well. This included recognizing the high degree of uncertainty with impacts and trends, involving the right people from the outset, and trying to be truly adaptive while also recognizing the constraints from lease rights, agency mandates, etc. However, there were some serious weaknesses with the AEM too and an exploration of these leads to the following lessons/recommendations for future adaptive management processes:

- Start small and pace/scale development with level of learning
- Define in detail what the adaptive management process will and will not address
- Ensure a solid baseline prior to starting Adaptive Management
- Make sure there is a solid agency commitment to fund monitoring
- Have a "fall back" plan should monitoring or adaptive management process not be fully carried out
- Set up adaptive management process so that private citizens can effectively participate.

<u>Notes from Mr. Aengst's talk</u>: I will discuss lessons from the AM process in the PAPA area, some weaknesses in the setup, and what it means for BLM elsewhere. An initial point: This (gas

development) is happening FAST. There is a rapidly changing landscape in the Pinedale and Jonah gas fields.

The Record of Decision was predicated on the resource protection alternative, and protection measures to monitor air and wildlife. The second prong of this resource protection alternative was Adaptive Environmental Management (AEM).

There were positive attributes; the conservation community supported it and there were no appeals, because of the community's faith and hopes in the process. What it did right: There was, prior to the process, a high degree of uncertainty. In the process, BLM effectively brought all stakeholders and groups to table. Another aspect making this an effective process was that BLM didn't attempt to mislead the groups-the agency laid out what the process could provide, and what it couldn't.

Any adaptive management process will face challenges. He will also discuss some weaknesses, which may be particular to Pinedale.

Weakness: the Pinedale Plan was incredibly ambitious, and attempted to take on too much. Is it really realistic to ask dozens of diverse stakeholders to come up with a consensus on xyz? To interpret the results of monitoring? To develop a transportation system in the area?

Challenge and weakness: There was a lack of adequate/any baseline information. This made it quite difficult for the groups to develop mid-course corrections. There was no course to gauge from.

Challenge: Some resources have significant time lag between the impact and when it shows up in monitoring, e.g., wildlife, air quality. What was missing from Pinedale was that there was no attempt to slow or stop development, and the drilling kept going.

Weakness: Inadequate funding and staffing. The Pinedale EIS recommended a full-time coordinator, but didn't get it due to a lack of funding. There was also insufficient funding for monitoring.

Weakness: Bad meeting times, no travel funds earmarked, and frequency and time commitments were pretty intense: meet on a weekly basis for 9 months straight. This amounted to hundreds of hours!

Lessons learned:

-Start small. Be conservative at first. Allow more as you learn more.

-Define in detail what the process will/not address.

-Ensure there is solid baseline information prior to starting AM- otherwise new data collection will be constrained and you won't have anything to compare it to.

-Make sure there is a solid agency commitment to fund monitoring. Don't rely exclusively on industry. And if there's not effective funding, the monitoring will fail.

-Have a fallback plan: At Pinedale, the drilling and road building went forward but the adaptive management did not.

Audience Discussion:

Q: Wants to clarify Robin Smith's characterization of winter drilling. The 5-year study to which you referred doesn't look at winter drilling in particular. Took some of the data from a 5 year study and tried to extrapolate it to winter drilling. The study itself recognized that no firm conclusions could be drawn re: the winter drilling from the study. WRA is mounting a legal challenge to that decision to drill in the winter.

Q: How could the BLM authorize a drilling period at all while the group wasn't established, if it took 3 years to form and just last week was chartered?

> A: the data has been continually collected during the 2 year process and we're going to give that to the group now that it's formed.
>
> Robin Smith (comment): I disagree with Peter Aengst's comment that the data hasn't been assimilated but I agree that the data was lacking when we started. It hasn't been assimilated yet. This is a long term process and 1-2 years isn't going to tell us much.

Q: Were the majority of these Applications for Permit to Drill (APDs) on new or existing leases, and was there a 2-tiered process like traditional NEPA?

A: all were on existing leases.

A: not sure I understand- we did an EIS…

Q: Did you do a Categorical exclusion/EA/Then EIS?

A: BLM's process is different than the Forest Service; in the 1988 RMP, the whole area available for leasing. Then Pinedale EIS, and finally EA for each APD.

Q: From a BMP perspective, it looked like you could drill up to 16 wells from one pad. Was this incorporated into the EIS and ROD?

A: There are technical constraints: in order to drill 16 drills off one pad, you must do it continuously, and this can't be done with 6 months winter range constrictions. But BLM had the ability to require companies to consider directional drilling.

Q: What baseline data that "wasn't there" are you referring to?

A: Baseline data that would've allowed us to compare and see what the impacts were. 100 percent of the area was already leased. BLM had to put the constraint on how those leases are operated.

Appendix C – Questar – The Pinedale Anticline

Appendix D Questar Increasing Access By Minimizing Impacts on the Pinedale Anticline

Appendix E SPE 105644 Pad Development paper

Appendix F Simops Examples

Appendix G Water Management Examples

Appendix H West Tavaputs Plateau Project Study

Appendix I Modern Shale Primer, A DOE Publication