Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs

Final

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United States Environmental Protection Agency
Office of Water
Office of Ground Water and Drinking Water
Drinking Water Protection Division
Prevention Branch
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Executive Summary

> A USDW is defined as an aquifer or a portion of an aquifer that:
> A. 1. *Supplies any public water system; or*
>   2. *Contains sufficient quantity of groundwater to supply a public water system; and*
>   i. *currently supplies drinking water for human consumption; or*
>   ii. *contains fewer than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS); and*
> B. *Is not an exempted aquifer.*
>
> ***NOTE**:* Although aquifers with greater than 500 mg/L TDS are rarely used for drinking water supplies without treatment, the Agency believes that protecting waters with less than 10,000 mg/L TDS will ensure an adequate supply for present and future generations.

The U.S. Environmental Protection Agency (EPA, or the Agency) conducted a study that assesses the potential for contamination of underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids into coalbed methane (CBM) wells. To increase the effectiveness and efficiency of the study, EPA has taken a phased approach. Apart from using real world observations and gathering empirical data, EPA also evaluated the theoretical potential for hydraulic fracturing to affect USDWs. Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time. EPA's decision is consistent with the process outlined in the April, 2001 Final Study Design, which is described in Chapter 2 of this report.

The first phase of the study, documented in this report, is a fact-finding effort based primarily on existing literature to identify and assess the potential threat to USDWs posed by the injection of hydraulic fracturing fluids into CBM wells. EPA evaluated that potential based on two possible mechanisms. The first mechanism was the direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system). The second mechanism was the creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

EPA also reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing and found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells.

EPA has determined that in some cases, constituents of potential concern (section ES-6) are injected directly into USDWs during the course of normal fracturing operations. The use of diesel fuel in fracturing fluids introduces benzene, toluene, ethylbenzene, and xylenes (BTEX) into USDWs. BTEX compounds are regulated under the Safe Drinking Water Act (SDWA).

Given the concerns associated with the use of diesel fuel and the introduction of BTEX constituents into USDWs, EPA recently entered into a Memorandum of Agreement (MOA) with three major service companies to voluntarily eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for CBM production (USEPA, 2003). Industry representatives estimate that these three companies perform approximately 95 percent of the hydraulic fracturing projects in the United States. These companies signed the MOA on December 15, 2003 and have indicated to EPA that they no longer use diesel fuel as a hydraulic fracturing fluid additive when injecting into USDWs.

ES-1 How Does CBM Play a Role in the Nation's Energy Demands?

CBM production began as a safety measure in underground coalmines to reduce the explosion hazard posed by methane gas (Elder and Deul, 1974). In 1980, the U.S. Congress enacted a tax credit for non-conventional fuels production, including CBM production, as part of the Crude Oil Windfall Profit Act. In 1984, there were very few CBM wells in the U.S.; by 1990, there were almost 8,000 CBM wells (Pashin and Hinkle, 1997). In 1996, CBM production in 12 states totaled about 1,252 billion cubic feet, accounting for approximately 7 percent of U.S. gas production (U.S. Department of Energy, 1999). At the end of 2000, CBM production from 13 states totaled 1.353 trillion cubic feet, an increase of 156 percent from 1992. During 2000, a total of 13,973 CBM wells were in production (GTI, 2001; EPA Regional Offices, 2001). According to the U.S. Department of Energy, natural gas demand is expected to increase at least 45 percent in the next 20 years (U.S. Department of Energy, 1999). The rate of CBM production is expected to increase in response to the growing demand.

In evaluating CBM production and hydraulic fracturing activities, EPA reviewed the geology of 11 major coal basins throughout the United States (Figure ES-1). The basins shown in red have the highest CBM production volumes. They are the Powder River Basin in Wyoming and Montana, the San Juan Basin in Colorado and New Mexico, and the Black Warrior Basin in Alabama. Hydraulic fracturing is or has been used to stimulate CBM wells in all basins, but it has not frequently been used in the Powder River, Sand Wash, or Pacific Coal Basins. Table ES-1 provides production statistics for 2000 and information on hydraulic fracturing activity for each of the 11 basins in 2000.

Figure ES-1. Major United States Coal Basins

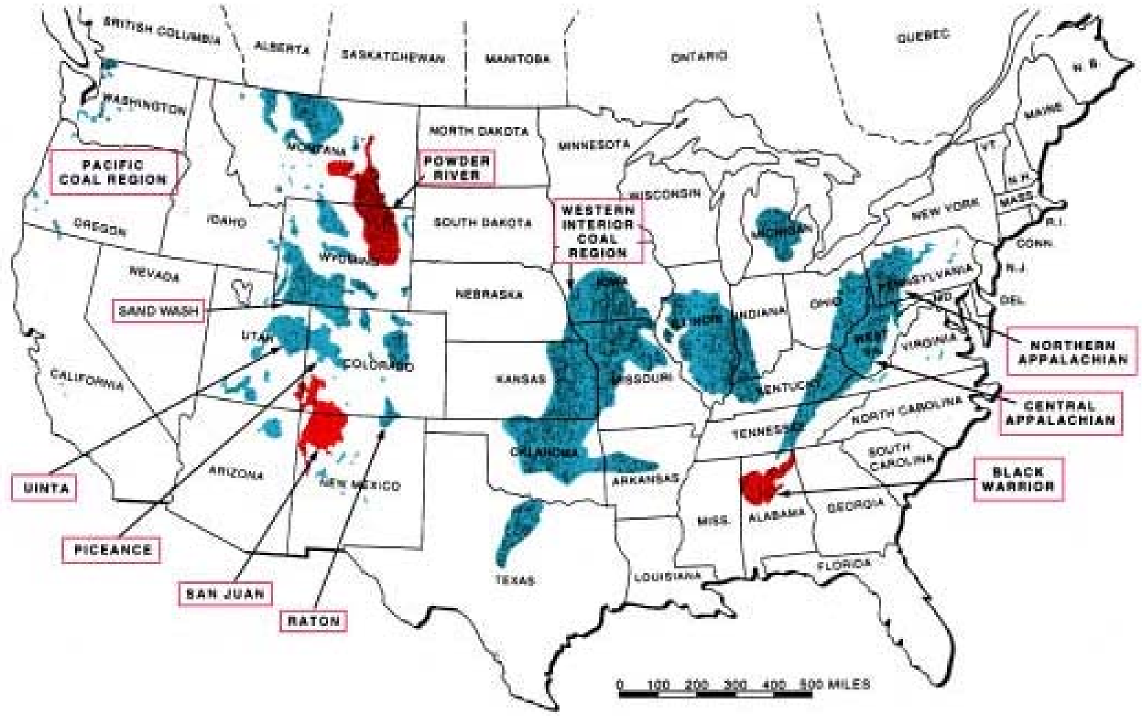


Table ES-1. Coal Basins Production Statistics and Activity Information in the U.S.

Basin	Number of CBM Producing Wells (Year 2000)*	Production of CBM in Billions of Cubic Feet (Year 2000)*	Does Hydraulic Fracturing Occur?
Powder River	4,200	147	Yes (but infrequently)
Black Warrior	3,086	112	Yes
San Juan	3,051	925	Yes
Central Appalachian	1,924	52.9	Yes
Raton Basin	614	30.8	Yes
Uinta	494	75.7	Yes
Western Interior	420	6.5	Yes
Northern Appalachian	134	1.41	Yes
Piceance	50	1.2	Yes
Pacific Coal	0	0	Yes (but infrequently)
Sand Wash	0	0	Yes (but infrequently)

* Data provided by the Gas Technology Institute and EPA Regional Offices. Production figures include CBM extracted using hydraulic fracturing and other processes.

ES-2 What Is Hydraulic Fracturing?

CBM gas is not structurally trapped in the natural fractures in coalbeds. Rather, most of the methane is adsorbed to the coal (Koenig, 1989; Winston, 1990; Close, 1993). To extract the CBM, a production well is drilled through the rock layers to intersect the coal seam that contains the CBM. Next, fractures are created or existing fractures are enlarged in the coal seam through which the CBM can be drawn to the well and pumped to the surface.

Figure ES-2 illustrates what occurs in the subsurface during a typical hydraulic fracturing event. This diagram shows the initial fracture creation, fracture propagation, proppant placement, and the subsequent fracturing fluid recovery/groundwater extraction stage of the CBM production process. The actual extraction of CBM generally begins after a period of fluid recovery/groundwater extraction. The hydraulically created fracture acts as a conduit in the rock or coal formation, allowing the CBM to flow more freely from the coal seams, through the fracture system, and to the production well where the gas is pumped to the surface.

To create or enlarge fractures, a thick fluid, typically water-based, is pumped into the coal seam at a gradually increasing rate and pressure. Eventually the coal seam is unable to accommodate the fracturing fluid as quickly as it is injected. When this occurs, the pressure is high enough that the coal fractures along existing weaknesses within the coal (steps 1 and 2 of Figure ES-1). Along with the fracturing fluids, sand (or some other propping agent or "proppant") is pumped into the fracture so that the fracture remains "propped" open even after the high fracturing pressures have been released. The resulting proppant-containing fracture serves as a conduit through which fracturing fluids and groundwater can more easily be pumped from the coal seam (step 3 of Fig. ES-1).

To initiate CBM production, groundwater and some of the injected fracturing fluids are pumped out (or "produced" in the industry terminology) from the fracture system in the coal seam (step 4 of Figure ES-1). As pumping continues, the pressure eventually decreases enough so that methane desorbs from the coal, flows toward, and is extracted through the production well (step 5 of Figure ES-1). In contrast to conventional gas production, the amount of water extracted declines proportionally with increasing CBM production. In some basins, huge volumes of groundwater are extracted from the production well to facilitate the production of CBM.

Figure ES-2. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells

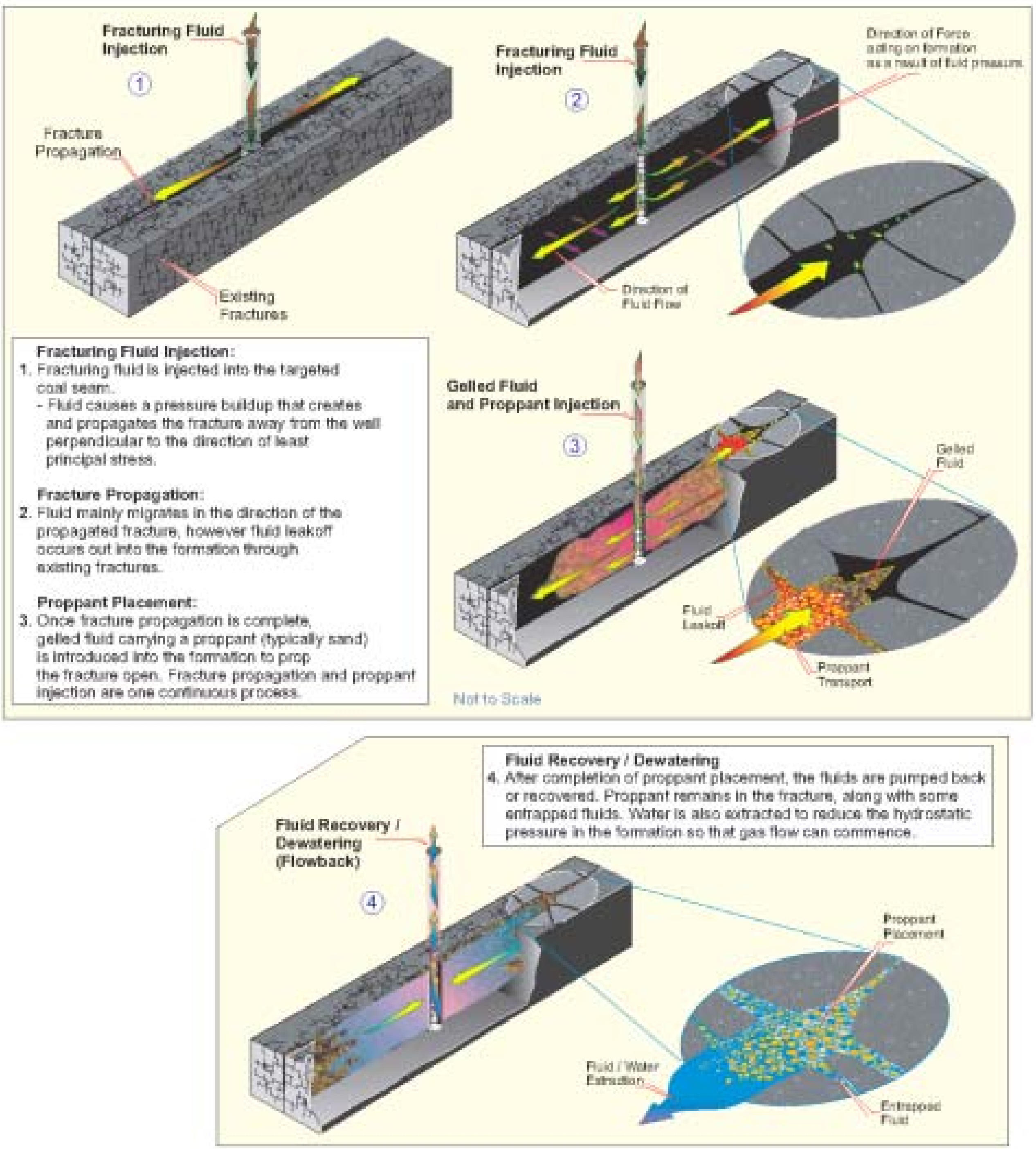
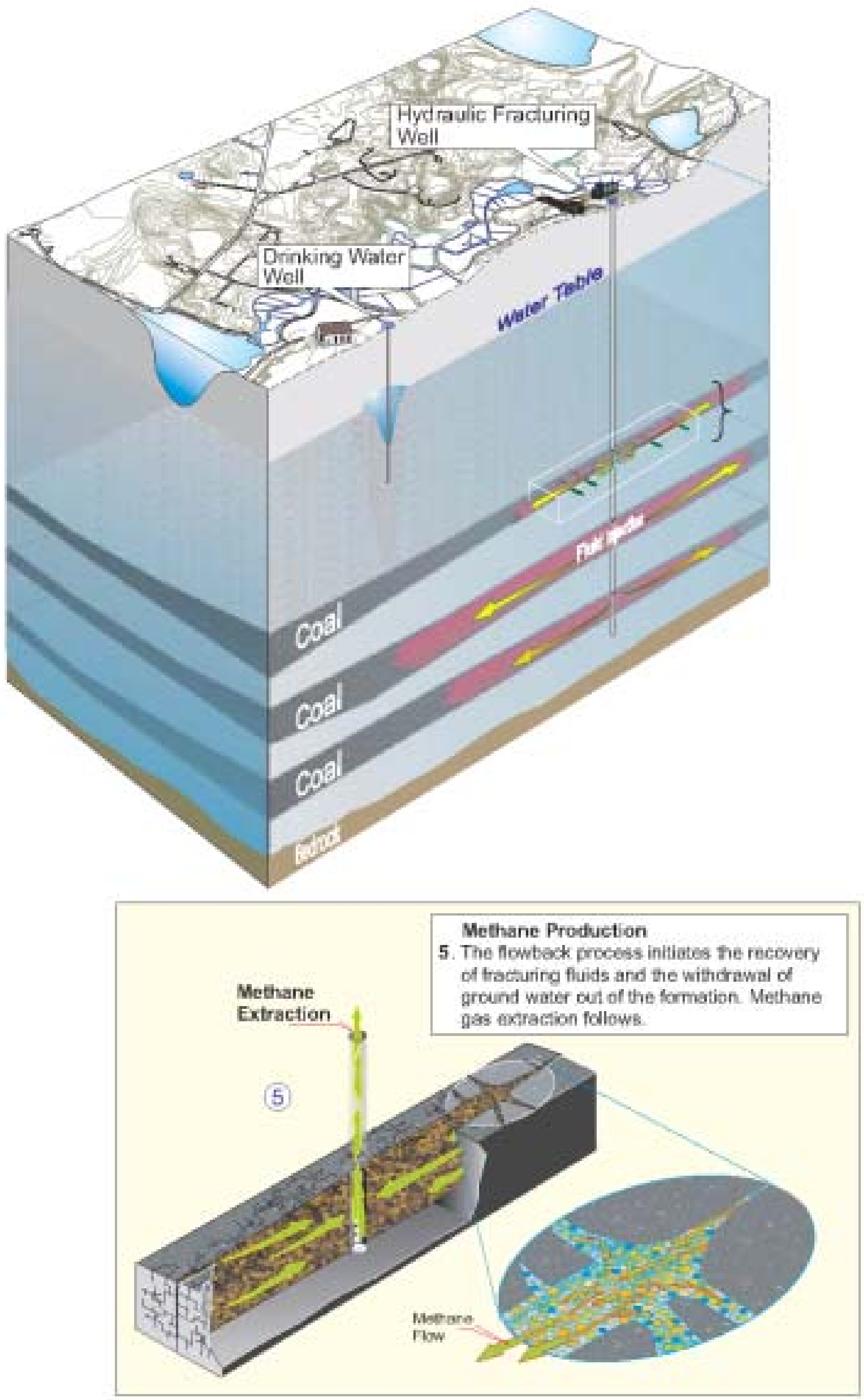


Figure ES-2. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells (Continued)



ES-3 Why Did EPA Evaluate Hydraulic Fracturing?

SDWA requires EPA and EPA-authorized states to have effective programs to prevent underground injection of fluids from endangering USDWs (42 U.S.C. 300h et seq.). Underground injection is the subsurface emplacement of fluids through a well bore (42 U.S.C. 300h(d)(1)). Underground injection endangers drinking water sources if it may result in the presence of any contaminant in underground water which supplies or can reasonably be expected to supply any public water system, and if the presence of such a contaminant may result in such system's noncompliance with any national primary drinking water regulation (i.e., maximum contaminant levels (MCLs)) or may otherwise adversely affect the health of persons (42 U.S.C. 300h(d)(2)). SDWA's regulatory authority covers underground injection practices, but the Act does not grant authority for EPA to regulate oil and gas production.

In 1997, the Eleventh Circuit Court ruled, in *LEAF v. EPA* [LEAF v. EPA, 118F.3d 1467 (11th Circuit Court of Appeals, 1997)], that because hydraulic fracturing of coalbeds to produce methane is a form of underground injection, Alabama's EPA-approved Underground Injection Control (UIC) Program must effectively regulate this practice. In the wake of the Eleventh Circuit's decision, EPA decided to assess the potential for hydraulic fracturing of CBM wells to contaminate USDWs. EPA's decision to conduct this study was also based on concerns voiced by individuals who may be affected by CBM development, Congressional interest, and the need for additional information before EPA could make any further regulatory or policy decisions regarding hydraulic fracturing.

The Phase I study is tightly focused to address hydraulic fracturing of CBM wells and does not include other hydraulic fracturing practices (e.g., those for petroleum-based oil and gas production) because: (1) CBM wells tend to be shallower and closer to USDWs than conventional oil and gas production wells; (2) EPA has not heard concerns from citizens regarding any other type of hydraulic fracturing; and (3) the Eleventh Circuit litigation concerned hydraulic fracturing in connection with CBM production. The study also does not address potential impacts of non-injection related CBM production activities, such as impacts from groundwater removal or production water discharge. EPA did identify, as part of the fact-finding process, citizen concerns regarding groundwater removal and production water.

ES-4 What Was EPA's Project Approach?

Based on public input, EPA decided to carry out this study in discrete phases to better define its scope and to determine if additional study is needed after assessing the results of the preliminary phase(s). EPA designed the study to have three possible phases, narrowing the focus from general to more specific as findings warrant. This report describes the findings from Phase I of the study. The goal of EPA's hydraulic fracturing Phase I study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into CBM wells and to determine based on these findings, whether further study is warranted.

Phase I is a fact-finding effort based primarily on existing literature. EPA reviewed water quality incidents potentially associated with CBM hydraulic fracturing, and evaluated the theoretical potential for CBM hydraulic fracturing to affect USDWs. EPA researched over 200 peer-reviewed publications, interviewed approximately 50 employees from industry and state or local government agencies, and communicated with approximately 40 citizens and groups who are concerned that CBM production affected their drinking water wells.

For the purposes of this study, EPA assessed USDW impacts by the presence or absence of documented drinking water well contamination cases caused by CBM hydraulic fracturing, clear and immediate contamination threats to drinking water wells from CBM hydraulic fracturing, and the potential for CBM hydraulic fracturing to result in USDW contamination based on two possible mechanisms as follows:

1. The direct injection of fracturing fluids into a USDW in which the coal is located (Figure ES-3), or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. The creation of a hydraulic connection between the coalbed formation and an adjacent USDW (Figure ES-4).

Figure ES-3. Hypothetical Mechanisms - Direct Fluid Injection into a USDW (Where Coal Lies Within a USDW or USDWs)

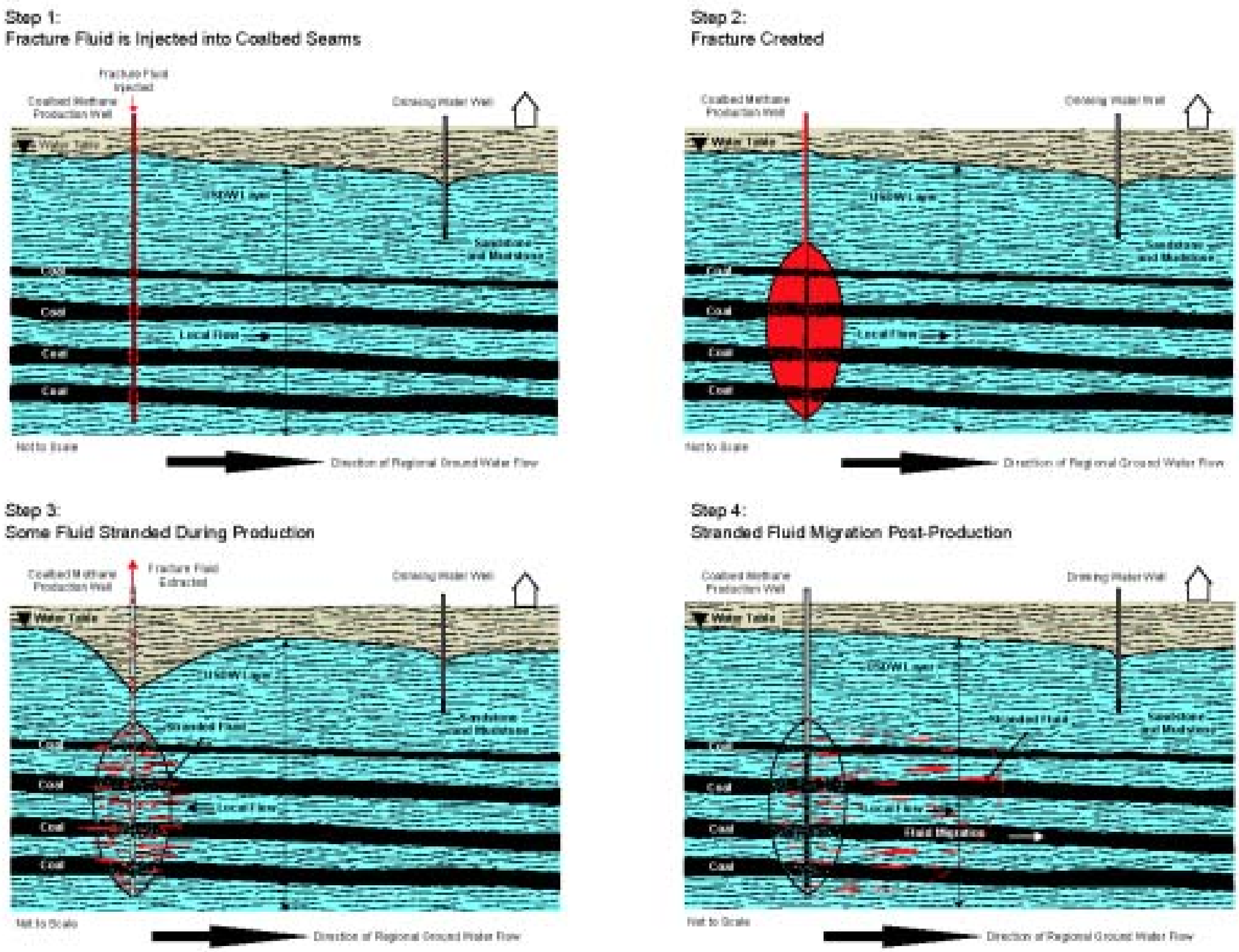
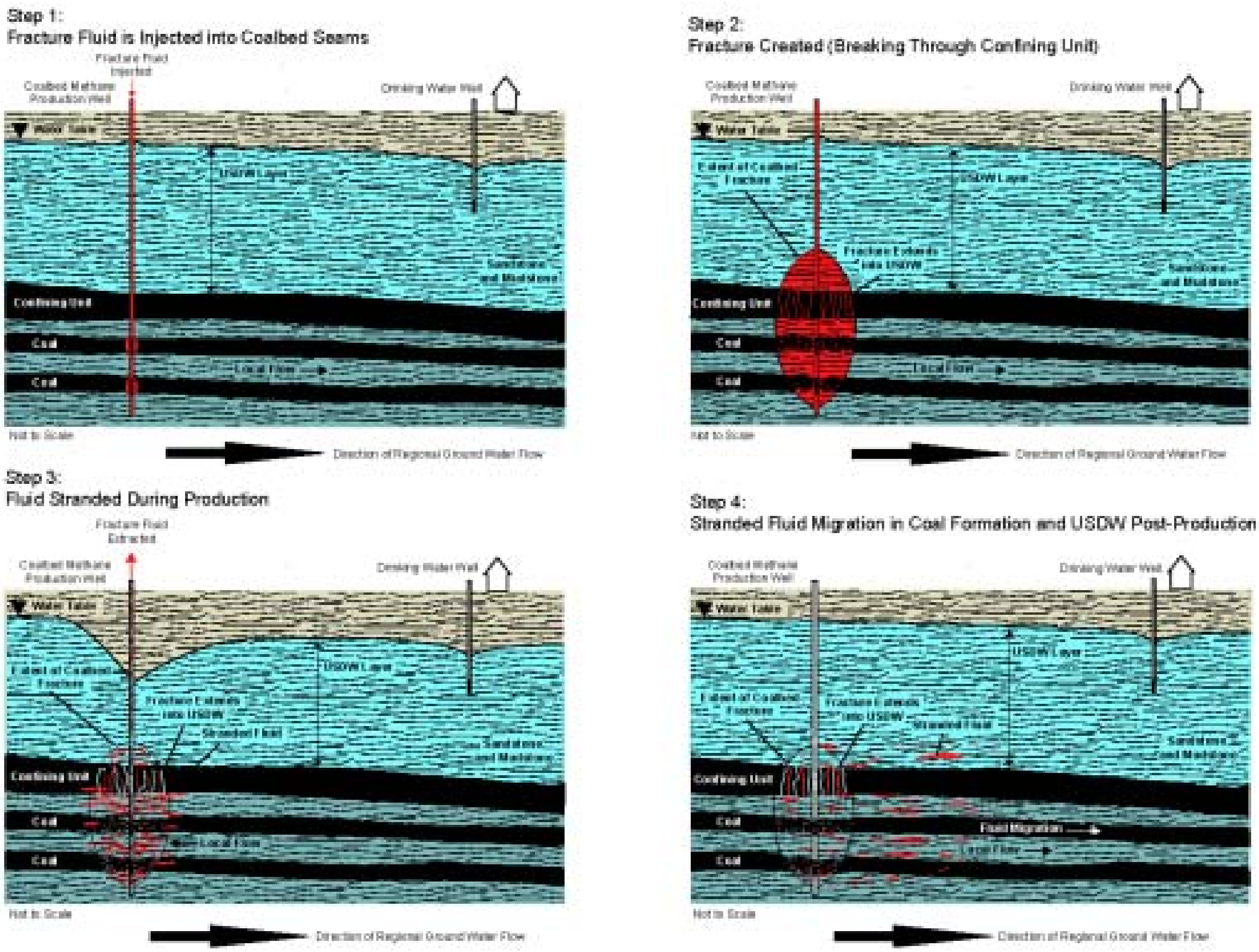


Figure ES-4. Hypothetical Mechanisms - Fracture Creates Connection to USDW



ES-5 How Do Fractures Grow?

In many CBM-producing regions, the target coalbeds occur within USDWs, and the fracturing process injects "stimulation" fluids directly into the USDWs. In other production regions, target coalbeds are adjacent to the USDWs (i.e., either higher or lower in the geologic section). Because shorter fractures are less likely to extend into a USDW or connect with natural fracture systems that may transport fluids to a USDW, the extent to which fractures propagate vertically influences whether hydraulic fracturing fluids could potentially affect USDWs.

The extent of the fractures is difficult to predict because it is controlled by the characteristics of the geologic formation (including the presence of natural fractures), the fracturing fluid used, the pumping pressure, and the depth at which the fracturing is being performed. Fracture behavior through coals, shales, and other geologic strata commonly present in coal zones depends on site-specific factors such as the relative thickness and in-situ stress differences between the target coal seam(s) and the surrounding geologic strata, as well as the presence of pre-existing natural fractures. Often, a high stress contrast between adjacent geologic strata results in a barrier to fracture propagation. An example of this would be where there is a geologic contact between a coalbed and an overlying, thick, higher-stress shale.

Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, highly cleated coal seams will prevent fractures from growing vertically. When the fracturing fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam (see Appendix A).

Deep vertical fractures can propagate vertically to shallower depths and develop a horizontal component (Nielsen and Hansen, 1987, as cited in Appendix A: DOE, Hydraulic Fracturing). In the formation of these "T-fractures," the fracture tip may fill with coal fines or intercept a zone of stress contrast, causing the fracture to turn and develop horizontally, sometimes at the contact of the coalbed and an overlying formation. (Jones et al., 1987; Morales et al., 1990). For cases where hydraulically induced fractures penetrate into, or sometimes through, formations overlying coalbeds, they are most often attributed to the existence of pre-existing natural fractures or thinly inter-bedded layering.

ES-6 What Is in Hydraulic Fracturing Fluids?

Fracturing fluids consist primarily of water or inert foam of nitrogen or carbon dioxide. Other constituents can be added to fluids to improve their performance in optimizing fracture growth. Components of fracturing fluids are stored and mixed on-site. Figures ES-5 and ES-6 show fluids stored in tanks at CBM well locations.

During a hydraulic fracturing job, water and any other additives are pumped from the storage tanks to a manifold system placed on the production wells where they are mixed and then injected under high pressure into the coal formation (Figure ES-6). The hydraulic fracturing in CBM wells may require from 50,000 to 350,000 gallons of fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant (Holditch et al., 1988 and 1989; Jeu et al., 1988; Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991, 1993a, and 1993b). More typical injection volumes, based on average injection volume data provided by Halliburton for six basins, indicate a maximum average injection volume of 150,000 gallons of fracturing fluids per well, with a median average injection volume of 57,500 gallons per well (Halliburton, Inc., 2003).

Figure ES-5. Water used for the fracturing fluid is stored on-site in large, upright storage tanks and in truck-mounted tanks.

EPA reviewed material safety data sheets to determine the types of additives that may be present in fracturing fluids. Water or nitrogen foam frequently constitutes the solute in fracturing fluids used for CBM stimulation. Other components of fracturing fluids contain benign ingredients, but in some cases, there are additives with constituents of potential concern. Because much more gel can be dissolved in diesel fuel as compared to water, the use of diesel fuel increases the efficiency in transporting proppant in the fracturing fluids. Diesel fuel is the additive of greatest concern because it introduces BTEX compounds, which are regulated by SDWA.

A thorough discussion of fracturing fluid components and fluid movement is presented in Chapter 4.

Figure ES-6. The fracturing fluids, additives, and proppant are pumped from the storage tanks to a manifold system placed on the wellhead where they are mixed just prior to injection.

ES-7 Are Coalbeds Located within USDWs?

EPA reviewed information on 11 major coal basins to determine if coalbeds are co-located with USDWs and to understand the CBM activity in the area. If coalbeds are located within USDWs, then any fracturing fluids injected into coalbeds have the potential to contaminate the USDW. As described previously, a USDW is not necessarily currently used for drinking water and may contain groundwater unsuitable for drinking without treatment. EPA found that 10 of the 11 basins may lie, at least in part, within USDWs. Table ES-2 identifies coalbed basin locations in relation to USDWs and summarizes evidence used as the basis for the conclusions.

ES-8 Did EPA Find Any Cases of Contaminated Drinking Water Wells Caused by Hydraulic Fracturing in CBM Wells?

EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells. EPA reviewed studies and follow-up investigations conducted by state agencies in response to citizen reports that CBM production resulted in water quality and quantity incidents. In addition, EPA received reports from concerned citizens in each area with significant CBM development. These complaints pertained to the following basins:

- San Juan Basin (Colorado and New Mexico);
- Powder River Basin (Wyoming and Montana);
- Black Warrior Basin (Alabama); and
- Central Appalachian Basin (Virginia and West Virginia).

Examples of concerns and claims raised by citizens include:

- Drinking water with strong, unpleasant taste and odor.
- Impacts on fish, and surrounding vegetation and wildlife.
- Loss of water in wells and aquifers, and discharged water creating artificial ponds and swamps not indigenous to region.

Water quantity complaints were the most predominant cause for complaint by private well owners. After reviewing data and incident reports provided by states, EPA sees no conclusive evidence that water quality degradation in USDWs is a direct result of injection of hydraulic fracturing fluids into CBM wells and subsequent underground movement of these fluids. Several other factors may contribute to groundwater problems, such as various aspects of resource development, naturally occurring conditions, population growth, and historical well-completion or abandonment practices. Many of the incidents that were reported (such as water loss and impacts on nearby flora and fauna from discharge of produced water) are beyond the authorities of EPA under SDWA and the scope of Phase I of this study.

Table ES-2. Evidence in Support of Coal-USDW Co-Location in U.S. Coal Basins

Basin	Are coalbeds found within USDWs?	Explanation and/or evidence
San Juan	Yes	A large area of the Fruitland system produces water containing less than 10,000 mg/L total dissolved solid (TDS), the water quality criterion for a USDW. Analyses taken from a selected coal well area (16 of 27 wells) show that produce water containing less than 10,000 mg/L TDS (Kaiser et al., 1994).
Black Warrior	Yes	Some portions of the Pottsville Formation contain waters that meet the quality criteria of less than 10,000 mg/L TDS for a USDW. According to the Alabama Oil and Gas Board, some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels considerably higher than 10,000 mg/L (Alabama Oil and Gas Board, 2002). In the early 1990s, several authors reported fresh water production from coalbed wells at rates up to 30 gallons per minute (in Pashin et al., 1991; Ellard et al., 1992).
Piceance	Unlikely	The CBM producing Cameo Coal Zone and the lower aquifer system in the Green River Formation are more than 6,000 feet apart. The coal zone, lies at great depth, roughly 6,000 feet below the ground surface in a large portion of the basin (Tyler et al., 1998). A composite water quality sample taken from 4,637 to 5,430 feet deep within the Cameo Coal Zone in the Williams Fork Formation exhibited a TDS level of 15,500 mg/L (Graham, 2001). The produced water from CBM extraction in the Piceance Basin is of such low quality that it must be disposed of in evaporation ponds; re-injected into the formation from which it came; or re-injected at even greater depths (Tessin, 2001).
Uinta	Likely	The water quality in the Ferron and Blackhawk varies greatly with location, each having TDS levels below and above 10,000 mg/l (Utah Department of Natural Resources, 2002)
Powder River	Yes	A report prepared by the United States Geological Survey (USGS) showed that samples of water co-produced from 47 CBM wells in the Powder River Basin all had TDS levels of less than 10,000 mg/L (Rice et al., 2000). The water produced by CBM wells in the Powder River Coal Field commonly meets drinking water standards. In fact, production waters such as these have been proposed as a separate or supplemental source for municipal drinking water in some areas (DeBruin et al., 2000).
Central Appalachian	Likely	Depths of coal groups are coincident with fresh water in at least two of the states within the overall basin (Kelafant et al., 1988; Wilson, 2001; Foster, 1980; Hopkins, 1966; USGS, 1973). Anecdotal information suggests that private wells in Virginia are screened within coal seams (Wilson 2001; VDMME, 2001).

Basin	Are coalbeds found within USDWs?	Explanation and/or evidence
Northern Appalachian	Yes	The depth of each coal group within the basin is coincident with the depths of USDWs (Kelafant et al., 1988; Platt, 2001; Foster, 1980; Hopkins, 1996; USGS, 1973; Sedam and Stein, 1970; USGS, 1971; Duigon, 1985). Water quality data from eight historic Northern Appalachian Coal Basin projects show TDS levels below 10,000 mg/L (Zebrowitz et al., 1991).
Western Interior:		
Arkoma	Yes (in Arkansas) Unlikely (in Oklahoma)	The depths of coalbeds within Arkansas are coincident with depths to fresh water (Andrews et al., 1998; Cordova, 1963; Friedman, 1982; Quarterly Review, 1993). Based on maps provided by the Oklahoma Corporation Commission (OCC) showing depths of the 10,000 mg/L TDS groundwater quality boundary in Oklahoma, the location of CBM wells and USDWs would most likely not coincide in that state. This is based on depths to coals typically greater than 1,000 feet (Andrews et al., 1998) and depths to the base of the USDW typically less than 900 feet (OCC Depth to Base of Treatable Water Map Series, 2001).
Cherokee	Yes	The depths of coalbeds in Kansas are coincident with depths to fresh water (Quarterly Review, 1993; Macfarlane, 2001; DASC, 2001a).
Forest City	Unlikely	The thinness of the aquifer suggests that there is significant separation from the deeper coalbeds within the basin (Bostic et al., 1993; DASC, 2001b; Condra and Reed, 1959; Flowerday et al., 1998).
Raton	Yes	Water quality results from CBM wells in the Raton Basin demonstrate TDS content of less than 10,000 mg/L. Nearly all wells surveyed show a TDS of less than 2,500 mg/L, and more than half had TDS of less than 1,000 mg/L (National Water Summary, 1984).
Sand Wash	Yes	Two gas companies produced water from coals that showed TDS levels below 10,000 mg/L. At Craig Dome in Moffat County, Cockrell Oil Corporation drilled 16 CBM wells. The wells yielded large volumes of fresh water with TDS <1,000 mg/L (Colorado Oil and Gas Commission, 2001). Fuelco was operating 11 wells along Cherokee arch. Water pumped from the wells contained 1,800 mg/L of TDS and was discharged to the ground under a National Pollution Discharge Elimination System (NPDES) permit (Quarterly Review, 1993).
Pacific and Central Coal Regions	Yes	Data from a 1984 study demonstrates the co-location of a coal seam and a USDW in Pierce County. Water quality information from four gas test wells indicates TDS levels between 1,330 and 1,660 mg/L, well below the 10,000 mg/L criterion (Dion, 1984). Wells in the basalts commonly yield 150 to 3,000 gallons per minute. TDSs levels in the water produced generally range from 250 to 500 mg/L (Dion, 1984).

ES-9 What Are EPA's Conclusions?

Based on the information collected and reviewed, EPA has determined that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs. Continued investigation under a Phase II study is not warranted at this time.

As proposed in the Final Study Design (April 2001), Phase I of the study was a limited–scope assessment in which EPA would:

- Gather existing information to review hydraulic fracturing processes, practices, and settings;
- Request public comment to identify incidents that have not been reported to EPA;
- Review reported incidents of groundwater contamination and any follow-up actions or investigations by other parties (state or local agencies, industry, academia, etc.); and,
- Make a determination regarding whether further investigation is needed, based on the analysis of information gathered through the Phase I effort.

EPA's approach for evaluating the potential threat to USDWs was an extensive information collection and review of empirical and theoretical data. EPA reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing and found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells.

EPA also evaluated the theoretical potential for hydraulic fracturing to affect USDWs through one of two mechanisms:

1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).
2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

Regarding the question of injection of fracturing fluids directly into USDWs, EPA considered the nature of fracturing fluids and whether or not coal seams are co-located with USDWs. Potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are used in operations targeting coal seams that lie within USDWs. In particular, diesel fuel contains BTEX compounds, which are regulated under SDWA. However, the threat posed to USDWs by the introduction of some fracturing fluid constituents is reduced significantly by the removal of large quantities of groundwater (and injected fracturing fluids) soon after a well has been hydraulically fractured. In fact, CBM production is dependent on the removal of large quantities of groundwater. EPA believes that this groundwater production, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation, minimize the possibility that chemicals included in the fracturing fluids would adversely affect USDWs.

Because of the potential for diesel fuel to be introduced into USDWs, EPA requested, and the three major service companies agreed to, the elimination of diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for CBM production (USEPA, 2003). Industry representatives estimate that these three companies perform approximately 95 percent of the hydraulic fracturing projects in the United States.

In evaluating the second mechanism, EPA considered the possibility that hydraulic fracturing could cause the creation of a hydraulic connection to an adjacent USDW. The low permeability of relatively unfractured shale may help to protect USDWs from being affected by hydraulic fracturing fluids in some basins. If sufficiently thick and relatively unfractured shale is present, it may act as a barrier not only to fracture height growth, but also to fluid movement. Shale's ability to act as a barrier to fracture height growth is primarily due to the stress contrast between the coalbed and the shale. Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, when the fracturing fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam (see Appendix A).

Some studies that allow direct observation of fractures (i.e., mined-through studies) indicate many fractures that penetrate into, or sometimes through, one or more formations overlying coalbeds can be attributed to the existence of pre-existing natural fractures. However, given the concentrations and flowback of injected fluids, and the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation, EPA does not believe that possible hydraulic connections under these circumstances represent a significant potential threat to USDWs.

It is important to note that states with primary enforcement authority (primacy) for their UIC Programs implement and enforce their regulations, and have the authority under SDWA to place additional controls on any injection activities that may threaten USDWs. States may also have additional authorities by which they can regulate hydraulic fracturing. With the expected increase in CBM production, the Agency is committed to working with states to monitor this issue.

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List of Acronyms and Abbreviations

μg/g	*Micrograms per gram*
μg/L	*Micrograms per liter*
ADEM	*Alabama Department of Environmental Management*
Bbl/min	*Barrel per minute*
Bcf	*Billion cubic feet*
Bgs	*Below ground surface*
BHP	*Bottom hole pressure*
BLM	*Bureau of Land Management*
BTEX	*Benzene, toluene, ethylbenzene, xylenes*
Btu	*British thermal unit*
CBM	*Coalbed methane*
CDH	*Colorado Department of Health*
CCL	*Contaminant Candidate List*
CDWR	*Colorado Division of Water Resources*
CFR	*Code of Federal Regulations*
CMHPG	*Carboxymethylhydroxypropylguar*
COGCC	*Colorado Oil and Gas Conservation Commission*
DASC	*Data Access and Support Center*
DNR	*Department of Natural Resources*
DOE	*Department of Energy*
EPA	*Environmental Protection Agency*
g	*Gram*
g/mL	*Grams per milliliter*
GRI	*Gas Research Institute*
GTI	*Gas Technology Institute*
GSA	*Geological Survey of Alabama*
HCl	*Hydrochloric acid*

HEC	*Hydroxyethylcellulose*
HPG	*Hydroxypropylguar*
KCl	*Potassium chloride*
L	Liter
LEAF	*Legal Environmental Assistance Foundation*
Mcf	*Million cubic feet*
MCL	*Maximum contaminant level*
md	*Millidarcy*
mg/L	*Milligrams per liter*
mL	*Milliliter*
MOA	*Memorandum of Agreement*
MSDS	*Material Safety Data Sheet*
MTBE	*Methyl tert butyl ether*
NMOCD	*New Mexico Oil Conservation Division*
NPDEA	*National Pollution Discharge Elimination System*
OGB	*Oil and Gas Board*
OGWDW	*Office of Ground Water and Drinking Water*
P3D	*Pseudo 3 Dimensional*
PAH	*Polynuclear aromatic hydrocarbons*
POM	*Polycyclic organic matter*
ppm	*Parts per million*
PRBRC	*Powder River Basin Resource Council*
PRCMIC	*Powder River Coalbed Methane Information Council*
psi	*Pounds per square inch*
SDWA	*Safe Drinking Water Act*
SEO	*State Engineer's Office*
SJRA	*San Juan Regional Authority*
TBEG	*Texas Bureau of Economic Geology*

Tcf	*Trillion cubic feet*
TDS	*Total dissolved solids*
TGD	*Tennessee Geology Division*
UIC	*Underground Injection Control*
USBM	*United States Bureau of Mines*
USDW	*Underground Source of Drinking Water*
USGS	*United States Geological Survey*
VDMME	*Virginia Division of Oil and Gas, within the Department of Mines, Minerals and Energy*
wt.	*Weight*

Glossary

Adsorption	*Adhesion of gas molecules, ions or molecules in solution to the surface of solid bodies with which they are in contact.*
Alluvial aquifer	*A water-bearing deposit of unconsolidated material (e.g., sand and gravel) left behind by a river or other flowing water.*
Amphoteric	*Having both basic and acidic properties.*
Anaerobic Bacteria	*Bacteria that thrive in oxygen-poor environments.*
Anisotropic	*Having some physical property that varies with direction from a given location.*
Annulus	*The space between the casing (the material that is used to keep the well stable; typically this material is steel) in a well and the wall of the hole, or between two concentric strings of casing, or between casing and tubing.*
Anticline	*A fold of layered, sedimentary rocks whose core contains stratigraphically older rocks, the shape of the fold is generally convex upward.*
Aureole	*A ring surrounding a volcanic intrusion where the surrounding rock has been altered.*
Azimuth	*The direction of a horizontal line as measured on an imaginary horizontal circle.*
Bedrock aquifer	*An aquifer located in the solid rock underlying unconsolidated surface materials (i.e., sediment). Solid rock can bear water when it is fractured.*
Billion cubic feet	*A unit typically used to define gas production volumes in the coalbed methane industry; 1 Bcf is roughly equivalent to the volume of gas required to heat approximately 12,000 households for one year (based on the Department of Energy's average household energy consumption statistic, 2001).*
Biogenic	*A direct product of the physiological activities of organisms.*
Bituminous	*From the base word bitumen, referring to a general term for various solid and semi-solid hydrocarbons that are able to join together and are soluble in carbon bisulfide (e.g., asphalts).*
Breaker	*A fracturing fluid additive that is added to break down the viscosity of the fluid.*
Breccia	*A coarse-grained clastic rock composed of angular broken rock fragments held together by a mineral cement or a fine-grained matrix.*
Brecciated	*Consisting of angular fragments cemented together.*
Btu	*British thermal unit; a unit of measure used to define energy.*
Butt Cleat	*The coal cleat set that abuts into face cleats.*
Capture Zone	*The portion of an aquifer that contributes water to a particular pumping well.*

Cavitation Cycling — *Also known as cavity completion, an alternative completion technique to hydraulic fracturing, in which a cavity is generated by alternately pumping in nitrogen and blowing down pressure.*

Cleats — *Natural fractures in coal that often occur in systematic sets, through which gas and water can flow.*

CMHPG — *Carboxymethyl hydroxypropylguar; a form of guar gel.*

Craton — *A part of the earth's crust that has attained stability and has been relatively undeformed for a long time; the term is restricted to continents, and includes both shield and platform.*

Crosslinker — *An additive that when added to a linear gel, will create a complex, high viscosity, pseduoplastic fracturing fluid.*

Crosslinked Gel — *A gel to which a crosslinker has been added (see crosslinker).*

Darcy — *A measure of the permeability of rock or sediment.*

Desorption — *Liberation of tightly held methane gas molecules previously bound to the solid surface of the coal.*

Epiclastic — *Formed from the fragments or particles broken away (by weathering and erosion) from pre-existing rocks to form an altogether new rock in a new place.*

Evapotranspiration — *The portion of precipitation returned to the air through evaporation and transpiration.*

Face Cleat — *A coal cleat set that is through-going and continuous.*

Flowback — *The process of causing fluid to flow back to the well out of a fracture after a hydraulic fracturing event is completed.*

Fracture Conductivity — *The capability of the fracture to conduct fluids under a given hydraulic head difference.*

Geophone — *A seismic detector, placed on or in the ground, that responds to ground motion at its point of location.*

Graben — *An elongate, down-dropped block that is bounded by nearly parallel faults on both sides.*

Guar — *Organic powder thickener, typically used to make viscous fracturing fluids, completely soluble in hot and cold water, insoluble in oils, grease and hydrocarbons.*

HCl — *Molecular formula for hydrochloric acid; can be used in diluted form in the hydraulic fracturing process to fracture limestone formations and to clean up perforations in coalbed methane fracturing treatments.*

HEC — *Hydroxyethylcellulose; a form of guar gel.*

Hydraulic Conductivity — *(see permeability)*

Injectate — *In relation to the coalbed methane industry, this is the fracturing fluid injected into a coalbed methane well.*

Isopach — *A line drawn on a map through points of equal true thickness of a designated stratigraphic unit or group of stratigraphic units.*

Isotopic	*Rocks formed in the same environment, i.e. in the same sedimentary basin or geologic province.*
Isotropic	*A medium, such as unconsolidated sediments or a rock formation, whose properties are the same in all directions.*
KCl	*Molecular formula for potassium chloride.*
Lacustrine	*Pertaining to, produced by, or formed in a lake or lakes.*
Laminar Flow	*Water flow in which the stream lines remain distinct and the flow direction at every point remains unchanged with time; non-turbulent flow.*
Leakoff	*The magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. In common usage, leakoff is often considered the movement of fluid out of primary fractures and into a geologic formation, either through small existing permeable paths (connected pores and natural fracture networks) or through small pathways created or enlarged in the rock through the fracturing process.*
Lenticular	*Pertaining to a discontinuous, lens-shaped (saucer-shaped) stratigraphic body.*
Linear Gel	*A simple guar-based fracturing fluid usually formulated using guar and water with additives or guar with diesel fuel.*
Lithology	*The description of rocks based on mineralogic composition and texture.*
Millidarcy	*The customary unit of measurement of fluid permeability; equivalent to 0.001 Darcy.*
Mcf	*Million cubic feet; a unit typically used to define gas production volumes in the coalbed methane industry; 1 Mcf is roughly equivalent to the volume of gas required to heat approximately 12 households for one year (based on the Department of Energy's average household energy consumption statistic, 2001); Mcf can sometimes represent 1,000 cubic feet.*
mg/L	*Milligrams per liter; typically used to define concentrations of a dissolved compound in a fluid.*
Mined-through studies	*Mined-through studies are projects in which coalbeds have been actually mined through (i.e., the coal has been removed) so that remaining coal and surrounding rock can be inspected, after the coalbeds have been hydraulically fractured. These studies provide unique subsurface access to investigate coalbeds and surrounding rock after hydraulic fracturing.*
Moduli	*Plural of modulus (often referred to as bulk modulus), the ratio of stress to strain, abbreviated as "k". The bulk modulus is an elastic constant equal to the applied stress divided by the ratio of the change in volume to the original volume of a body.*
Overthrust	*A low-angle thrust fault of large scale, with total displacement (lateral or vertical) generally measured in kilometers.*
Pad	*An initial volume of fluid that is used to initiate and propagate a fracture before a proppant is placed.*
Paleochannels	*Old or ancient river channels preserved in the subsurface as lenticular sandstones.*

Permeability *The capacity of a porous rock, sediment, or soil to transmit a fluid; it is a measure of the relative ease of fluid flow under equal pressure and from equal elevations.*

Physiographic *A region of which all parts are similar in geologic structure and climate and which has had a unified geomorphic history; its relief features differ significantly from those of adjacent regions.*

Play *A productive coalbed methane formation, or a productive oil or gas deposit.*

Potentiometric *The total head of ground water, defined by the level to which water will rise in a well.*

ppm *Parts per million; typically used to define concentrations of a dissolved compound in a fluid; equivalent to 1 mg/L.*

Primacy *The right to self-establish, self-enforce and self-regulate environmental standards; this enforcement responsibility is granted by EPA to States and Indian Tribes.*

Primary porosity *The porosity preserved from some time between sediment deposition and the final rock-forming process; (e.g., the spaces between grains of sediment).*

Proppant *Granules of sand, ceramic or other minerals that are wedged within the fracture and act to "prop" it open after the fluid pressure from fracture injection has dissipated.*

psi *Pounds per square inch; a unit of pressure.*

Rank *The degree of metamorphism in coal; the basis of coal classification into a natural series from lignite to anthracite.*

Screen-out *Term used to describe a fracturing job where proppant placement has failed.*

Secondary porosity *The porosity created through alteration of rock, commonly by processes such as, dissolution and fracturing.*

Semianthracite *Term used to identify coal rank; specifically representing coal that possesses a fixed-carbon content of 86% to 92%.*

Stratigraphy *The study of rock strata; concerning all characteristics and attributes of rocks and their interpretation in terms of mode of origin and geologic history.*

Subbituminous *A black coal, intermediate in rank between lignite and bituminous.*

Subgraywacke *A sedimentary rock (sandstone) that contains less feldspar, and more and better-rounded quartz grains than graywacke; intermediate in composition between graywacke and orthoquartzite; it is lighter-colored and better-sorted, and has less matrix than greywacke.*

Surficial *Pertaining to or lying in or on a surface; specific to the surface of the earth.*

Syncline *A fold of layered, sedimentary rocks whose core contains stratigraphically younger rocks; shape of fold is generally concave upward.*

Tcf *Trillion cubic feet; a unit typically used to define gas production volumes in the coalbed methane industry; 1 Tcf is roughly equivalent to the volume of gas required to heat approximately 12 million households for one year (based on the Department of Energy's average household energy consumption statistic, 2001).*

Thermogenic	*A direct product of high temperatures, (e.g. Thermogenic methane).*
Toughness	*The point at which enough stress intensity has been applied to a rock formation, so that a fracture initiates and propagates.*
Transmissivity	*A measure of the amount of water that can be transmitted horizontally through a unit width by the full saturated thickness of the aquifer under a hydraulic gradient of one.*
Up-warp	*The uplift of a region; usually a result of the release of isostatic pressure, e.g. the melting of an ice sheet.*
Viscosity	*The property of a substance to offer internal resistance to flow; internal friction.*
Volcaniclastic	*Composed of fragments or particles, and related to volcanic processes either by forming as the result of explosive processes or due to the weathering and erosion of volcanic rocks.*

Chapter 1
Introduction

Section 1421 of SDWA tasks EPA with protecting USDWs for all current and future drinking water supplies across the country (see section 1.3 for the complete definition of a USDW). EPA's UIC Program is responsible for ensuring that fluids injected into the ground (for purposes including waste disposal, oil field brine disposal, enhanced recovery of oil and gas, mining, and emplacement of other fluids) do not endanger USDWs.

EPA, through its UIC Program, conducted a fact-finding effort based primarily on existing literature. The goal of this study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into coalbed methane wells and to determine, based on these findings, whether further study is warranted. For the purposes of this study, EPA assessed USDW impacts by the presence or absence of documented drinking water well contamination cases caused by coalbed methane hydraulic fracturing, clear and immediate contamination threats to drinking water wells from coalbed methane hydraulic fracturing, and the potential for coalbed methane hydraulic fracturing to result in USDW contamination based on two possible mechanisms as follows:

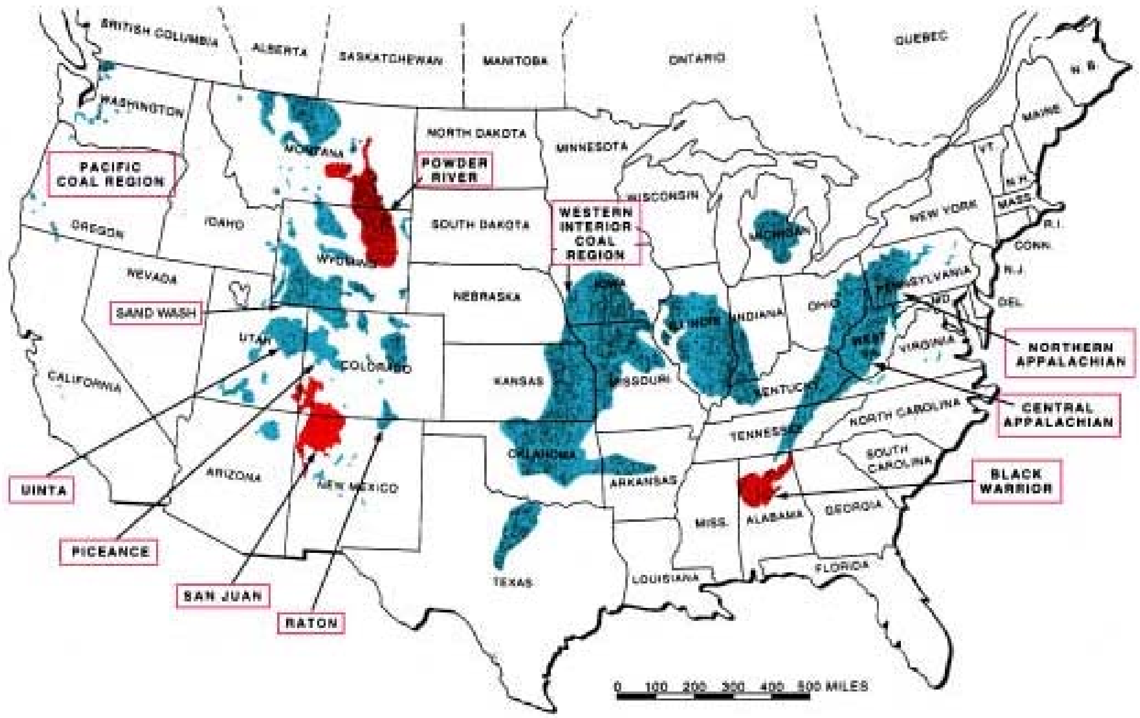
1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

EPA obtained information for this study from literature searches, field visits, a review of reported groundwater contamination incidents in areas where coalbed methane is produced, and solicitation of information from the public on any impacts to groundwater believed to be associated with hydraulic fracturing.

EPA also reviewed 11 major coal basins throughout the United States to determine if coalbeds are co-located with USDWs and to understand the coalbed methane activity in the area (Figure 1-1). The basins shown in red have the highest coalbed methane production volumes. They are the Powder River Basin in Wyoming and Montana, the San Juan Basin in Colorado and New Mexico, and the Black Warrior Basin in Alabama. Hydraulic fracturing is or has been used to stimulate coalbed methane wells in all basins, although it has not frequently been used in the Powder River, Sand Wash, or Pacific Coal Basins.

Figure 1-1. Locus Map of Major United States Coal Basins



1.1 EPA's Rationale for Conducting This Study

Although coalbed methane has many environmental advantages over traditional energy sources, concerns have been raised regarding the environmental impacts of coalbed methane production. Coalbed methane production in certain areas has led to groundwater depletion and production water discharge issues (i.e., issues that are not associated with the quality of USDWs). Citizens, state agencies, producers, and the regional EPA offices in those areas are working in concert to better understand and mitigate these potential problems.

This study examines the potential for hydraulic fracturing fluid injection into coalbed methane wells to contaminate USDWs. EPA conducted this study in response to allegations that hydraulic fracturing of coalbed methane wells has affected the quality of groundwater (i.e., issues that are associated with the mandates of the UIC Program). State oil and gas agencies receiving such complaints have indicated that, based on their investigations, hydraulic fracturing of coalbed methane wells has not contributed to water quality degradation in USDWs.

In response to an Eleventh Circuit Court of Appeals (hereafter, "the Court") decision [*LEAF v. EPA*, 118F.3d 1467 (11th Cir, 1997)], the State of Alabama recently supplemented its rules governing the hydraulic fracturing of wells to include additional requirements to protect USDWs during the hydraulic fracturing of coalbeds for methane production. Prior to the Court's decision, EPA had not considered hydraulic fracturing as an underground injection activity, because the Agency did not consider production well stimulation as an activity subject to UIC regulations. Nevertheless, the Court held that the injection of fluids for the purpose of hydraulic fracturing constitutes underground injection as defined under SDWA, that all underground injection must be regulated, and that hydraulic fracturing of coalbed methane wells in Alabama must be regulated under Alabama's UIC program.

In the wake of the Eleventh Circuit Court decision, EPA decided to assess the potential for hydraulic fracturing fluid injection into coalbed methane wells to contaminate USDWs. EPA's decision to conduct this study was also based on concerns voiced by individuals who may be affected by coalbed methane development, Congressional interest, and the need for additional information before EPA could make any further regulatory or policy decisions regarding hydraulic fracturing.

1.2 Overview of Hydraulic Fracturing

Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of oil and coalbed methane wells. The hydraulic fracturing process uses high hydraulic pressures to initiate a fracture. A hydraulically induced fracture acts as a conduit in the rock or coal formation that allows the oil or coalbed methane to travel more freely from the rock pores to the production well that can bring it to the surface.

In the case of coalbed methane gas production, the gas is not structurally "trapped" under pressure. Rather, most of the coalbed methane is adsorbed within small pores in the "micro-porous matrix" of the coal (Koenig, 1989; Winston, 1990; Close, 1993). When coalbed methane production begins, water is first pumped out (or "produced" in the industry terminology) from the fractures, joints, and cleats (i.e., tiny, disconnected clusters of fractures) in the coal until the pressure declines to the point that methane begins to desorb from the coal matrix itself (Gray, 1987).

To extract the coalbed methane, a production well is drilled through rock layers to intersect the coal seam that contains the coalbed methane. Next, a fracture is created or enlarged in the coal seam to connect the well bore to the coalbed joint/cleat system. To create such a fracture, a thick, water-based fluid is pumped into the coal seam at a gradually increasing rate. At a certain point, the coal seam will not be able to accommodate the fracturing fluid as quickly as it is being injected. When this occurs, the pressure is high enough that the coal gives way, and a fracture is created or an existing fracture is enlarged. To hold the fracture open, a propping agent, usually sand (commonly known as "proppant"), is pumped into the fracture so that when the pumping pressure is released, the fracture does not close completely because the proppant is "propping" it open. The resulting fracture filled with proppant becomes a conduit through which water can flow to the production well, thus depressurizing the coal matrix, allowing for the desorption of methane and its flow towards the production well.

The extent of the fracture in a coalbed is controlled by the characteristics of the geologic formation (including the presence of natural fractures), the fracturing fluid used, the pumping pressure, and the depth at which the fracturing is performed. Whether the fracture grows taller or longer is determined by the properties of the surrounding rock. A hydraulically created fracture will always take the path of least resistance through the coal seam and surrounding formations.

A more comprehensive discussion of the fracturing process and the fracturing fluids/additives used in hydraulic fracturing of coalbed methane wells is presented in Chapters 3 and 4, respectively.

1.3 EPA's Authority to Protect Underground Sources of Drinking Water

SDWA requires EPA and EPA-authorized states to have effective programs to prevent underground injection of fluids from endangering USDWs (42 U.S.C. 300h et seq.). Underground injection is the subsurface emplacement of fluids through a well bore (42 U.S.C. 300h(d)(1)). Underground injection endangers drinking water sources if it may result in the presence of any contaminant in underground water which supplies or can reasonably be expected to supply any public water system, and if the presence of such contaminant may result in such system's noncompliance with any national primary drinking water regulation (i.e., maximum contaminant levels) or may otherwise adversely affect the health of persons (42 U.S.C. 300h(d)(2)). SDWA's regulatory authority extends to underground injection practices; SDWA does not provide a general grant of authority for EPA to regulate oil and gas production.

A USDW is defined in the UIC regulations at 40 CFR 144.3 as an aquifer or a portion of an aquifer that:

> "A. 1. Supplies any public water system; or
>   2. Contains sufficient quantity of groundwater to supply a public water system; and
>   i. currently supplies drinking water for human consumption; or
>   ii. contains fewer than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS); and
>
> B. Is not an exempted aquifer."

The water quality standard for USDWs is more stringent than EPA's National Secondary Drinking Water Standards for potable water, which cover aesthetic concerns such as taste and odor. These secondary standards recommend a TDS limit of 500 mg/L (40 CFR 143.3).

An accurate understanding of the definition of USDW requires understanding of two other terms: public water system and aquifer exemption.

A public water system is defined at 40 CFR 141.2 as:

> "A system for the provision to the public of water for human consumption through pipes or, after August 5, 1998, other constructed conveyances, if such a system has at least 15 service connections or regularly serves an average of at least twenty-five individuals daily at least 60 days out of the year."

To better quantify the definition of USDW, EPA determined that any aquifer yielding more than 1 gallon per minute can be expected to provide sufficient quantity of water to serve a public water system and therefore falls under the definition of a USDW (U.S. EPA Memorandum, 1993). EPA also assumes that all aquifers contain sufficient quantity of groundwater to supply a public water system, unless proven otherwise through empirical data.

An aquifer exemption may be granted under certain circumstances. According to 40 CFR 144.3, an exempted aquifer meets the definition of a USDW, but has been exempted according to the procedures in 40 CFR 144.7. An aquifer, or portion thereof, can be designated as an exempted aquifer, if it meets the following criteria (40 CFR 146.4):

1. It does not currently serve as a source of drinking water; and,

2. It cannot now and will not in the future serve as a source of drinking water because it is:

    - Mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated to be commercially producible; or
    - Situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
    - So contaminated that it would be economically or technologically impractical to render that water fit for human consumption; or
    - Located over a Class III well mining area subject to subsidence or catastrophic collapse; or,

3. The TDS content of the groundwater is more than 3,000 and less than 10,000 mg/L and, it is not reasonably expected to supply a public water system.

All requests for aquifer exemptions must be approved by the EPA Administrator or an authorized representative. A list of exempted aquifers, for states where such exemptions exist, is maintained by the state agency managing the UIC program or the regional EPA office. A comprehensive list or map identifying all USDWs in every state does not exist. Identification of USDWs is an ongoing effort, as is EPA's consideration of aquifer exemptions. For example, coalbed methane production wells using hydraulic fracturing to stimulate production may be located in areas that coincide with existing aquifer exemptions.

Currently, injection associated with hydraulic fracturing of coalbed methane production wells is regulated only in Alabama under the state UIC program, and that injection activity falls under the category of Class II wells (Alabama Oil and Gas Board, Administrative Code, Oil and Gas Report 1, 400-3). Class II wells include the injection of brines and other fluids that are associated with oil and gas production.

1.4 Potential Effects of Hydraulic Fracturing of Coalbed Methane Wells on USDWs

EPA identified two possible mechanisms by which hydraulic fracturing fluid injection into coalbed methane wells might affect the quality of USDWs:

1. The direct injection of fracturing fluids into a USDW in which the coal is located (Figure 1-2), or injection of fracturing fluids into a coal seam which is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. The creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

Fracturing fluids can be directly or indirectly injected into a USDW, depending on the location of the coalbed relative to a USDW. In many coalbed methane-producing regions, the target coalbeds occur *within* USDWs, and the fracturing process injects stimulation fluids directly into the USDWs (Figure 1-2 at the end of the chapter). In other production regions, target coalbeds are adjacent to the USDWs, which are either higher or lower in the geologic section. EPA investigated the potential for fractures to extend through stratigraphic layers that separate coalbeds and USDWs and the potential for stimulation fluids to indirectly enter a USDW during the fracturing process (Figure 1-3 at the end of the chapter).

Local geologic conditions may interfere with the complete recovery of fracturing fluids injected into a formation. As a result, some of the fracturing fluids may be "stranded" in the USDW (Figures 1-2 and 1-3). Any hazardous constituents in the stimulation fluids could potentially contaminate groundwater in a USDW and any drinking water supplies that rely on the USDW.

1.5 Study Approach

Given the enormous variation in geology among and within coalbed basins in the United States, any initial evaluation of potential impacts by hydraulic fracturing of coalbeds on USDWs at a national level would necessarily be broadly focused. Based on public input, EPA decided to carry out this study in discrete phases to better define its scope and to determine if additional study is needed after assessing the results of the preliminary phase(s). EPA designed the study to have three possible phases, changing the focus from general to more specific as findings warrant.

Phase I of the study is a fact-finding effort based primarily on existing literature to identify and assess the potential threat to USDWs posed by hydraulic fracturing fluid injection into coalbed methane wells. It is designed to determine if site-specific detailed studies, including collection of new data, are needed. An overview of the methodology used for Phase I is provided below; a detailed discussion of this methodology is provided in Chapter 2.

In Phase I, EPA:

- Conducted a literature review for information on hydraulic fracturing processes, hydraulic fracturing fluids and additives, the geologic settings of and the hydraulic fracturing practices used in the 11 major coal basins (Figure 1-1), and the identification of coal seams that are co-located with USDWs.

- Published a request in the *Federal Register* (66 FR 39396 (U.S. EPA, 2001)) for information from the public, as well as governmental and regulatory agencies, regarding incidents of groundwater contamination believed to be associated with hydraulic fracturing of coalbed methane wells.

- Reviewed reported incidents of groundwater contamination and any follow-up actions or investigations by other parties such as state or local agencies, industry, and academia.

- Conducted field visits in three states.

In addition, EPA collaborated with the Department of Energy (DOE) to produce a document that details the technical aspects of hydraulic fracturing in the oil and gas industry. This document is included as Appendix A to this report.

EPA also provided support for a site-specific study, which was conducted by the Geological Survey of Alabama (GSA). This study attempts to address a concern that is central to USDW contamination and drawdown issues: the degree to which flow is confined within coalbeds in coalbed methane fields. Information on the GSA study is available at http://www.gsa.state.al.us/gsa/3DFracpage/3Dfracstudy.htm.

1.6 Stakeholder Involvement

EPA took several steps to fully involve the public and all stakeholders during the study. These steps included:

- Publishing *Federal Register* notices:

  - requesting comments on the study plan (65 FR 45774 (USEPA, 2000));
  - requesting information from the public on any impacts to groundwater believed to be associated with hydraulic fracturing of coalbed methane wells (66 FR 39396 (USEPA, 2001));
  - Requesting comments on the August 2002 draft of the study (67 FR 55249 (USEPA, 2002)).

- Holding a public meeting to obtain additional stakeholder input on the proposed study plan published in the July 2000 *Federal Register* notice (65 FR 45774 (USEPA, 2000))

- Providing periodic updates for stakeholders in the form of written communication.

- Maintaining a Web site where stakeholders can view the project documents and provide information to EPA.

EPA also received and reviewed comments from 105 commenters submitted in response to the August 2002 *Federal Register* notice (67 FR 55249 (USEPA, 2002)), which announced the availability of the August 2002 version of this Phase I study report. EPA incorporated many of these comments into this final Phase I report. A summary of the public comments and EPA's responses is provided in, "Public Comment and Response Summary for the Study on the Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water" (EPA 816-R-04-004), available on EPA's electronic docket.

1.7 Information Contained within This Report

This Phase I report is composed of an executive summary, 7 chapters, 11 attachments, and 2 appendices. The main chapters address the following topics:

- Chapter 2, Study Methodology, discusses in detail EPA's method for collecting information under Phase I of the study.

- Chapter 3, Characteristics of Coalbed Methane Production and Associated Hydraulic Fracturing Practices, discusses the hydraulic fracturing process as it applies to coalbed methane production.

- Chapter 4, Hydraulic Fracturing Fluids, describes the use and nature of hydraulic fracturing fluids and their additives. It also discusses EPA's evaluation of the fate and transport of fracturing fluids that are injected into targeted coal layers during the hydraulic fracturing process.

- Chapter 5, Summary of Coalbed Methane Basin Descriptions, briefly describes each of the 11 major coal basins in the United States and discusses the potential for impacts to USDWs in these basins.

- Chapter 6, Water Quality Incidents, in response to stakeholders' recommendations, summarizes water quality and quantity complaints received from citizens pertaining to hydraulic fracturing, coalbed methane production, and well stimulation.

- Chapter 7, Summary of Findings, summarizes the major findings presented in Chapters 3 through 6.

In addition, Chapters 3 through 6 contain numerous figures and tables to help readers visualize the hydraulic fracturing process and to help summarize some of the key information in the report.

The attachments to the report are a collection of in-depth hydrologic investigations of the 11 coal basins, focusing primarily on the coalbed methane production activities and the relationship between coalbed and USDW locations within these 11 basins. The attachments expand the discussions of Chapter 5 with greater details on the specific geology and gas production activities for the 11 basins.

Appendix A, Hydraulic Fracturing, contains DOE's technical report on hydraulic fracturing. Appendix B, Quality Assurance Protocol, explains the quality assurance and quality control measures EPA used to conduct this study.

Figure 1-2. Hypothetical Mechanism - Direct Fluid Injection Into a USDW (Coal within USDW)

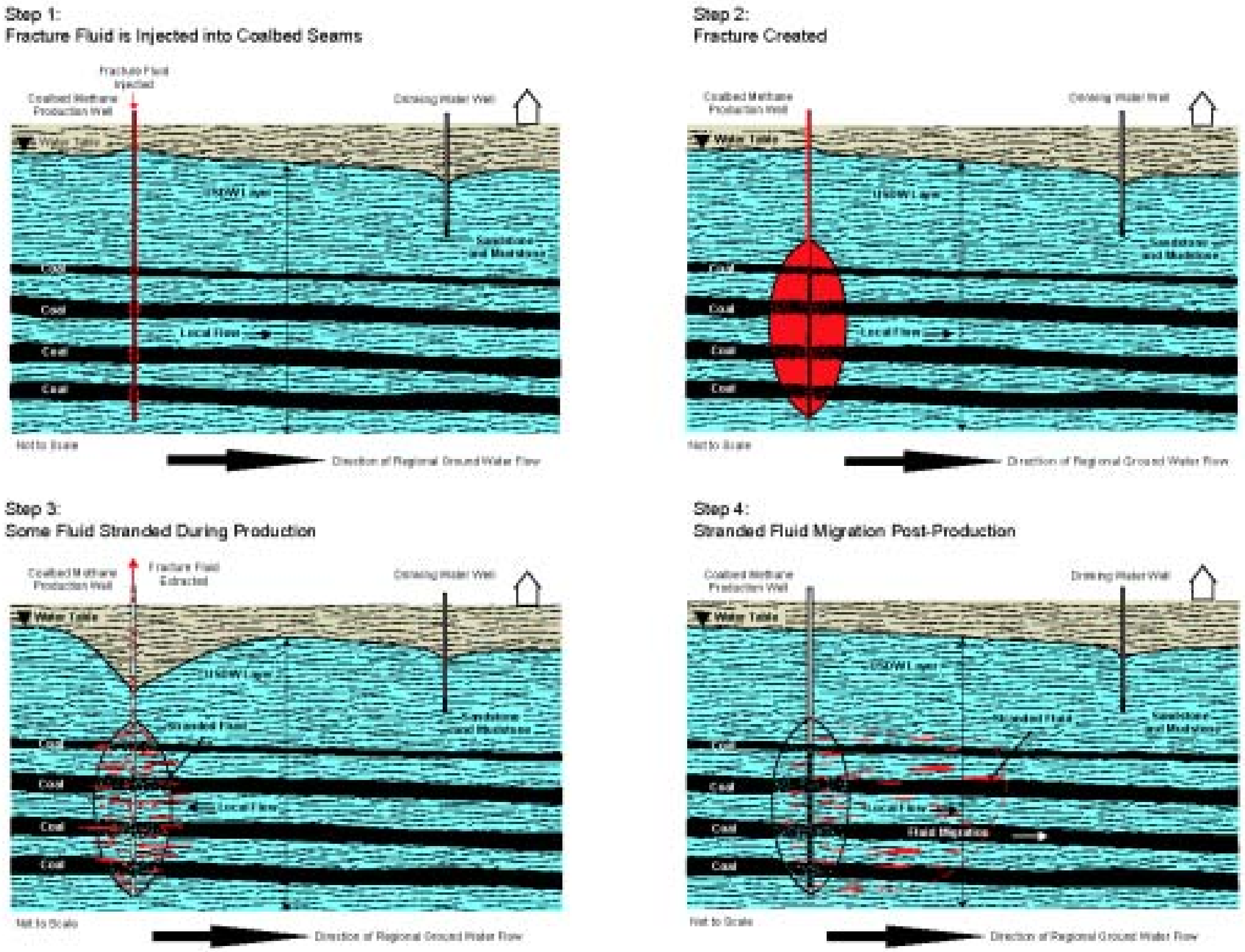
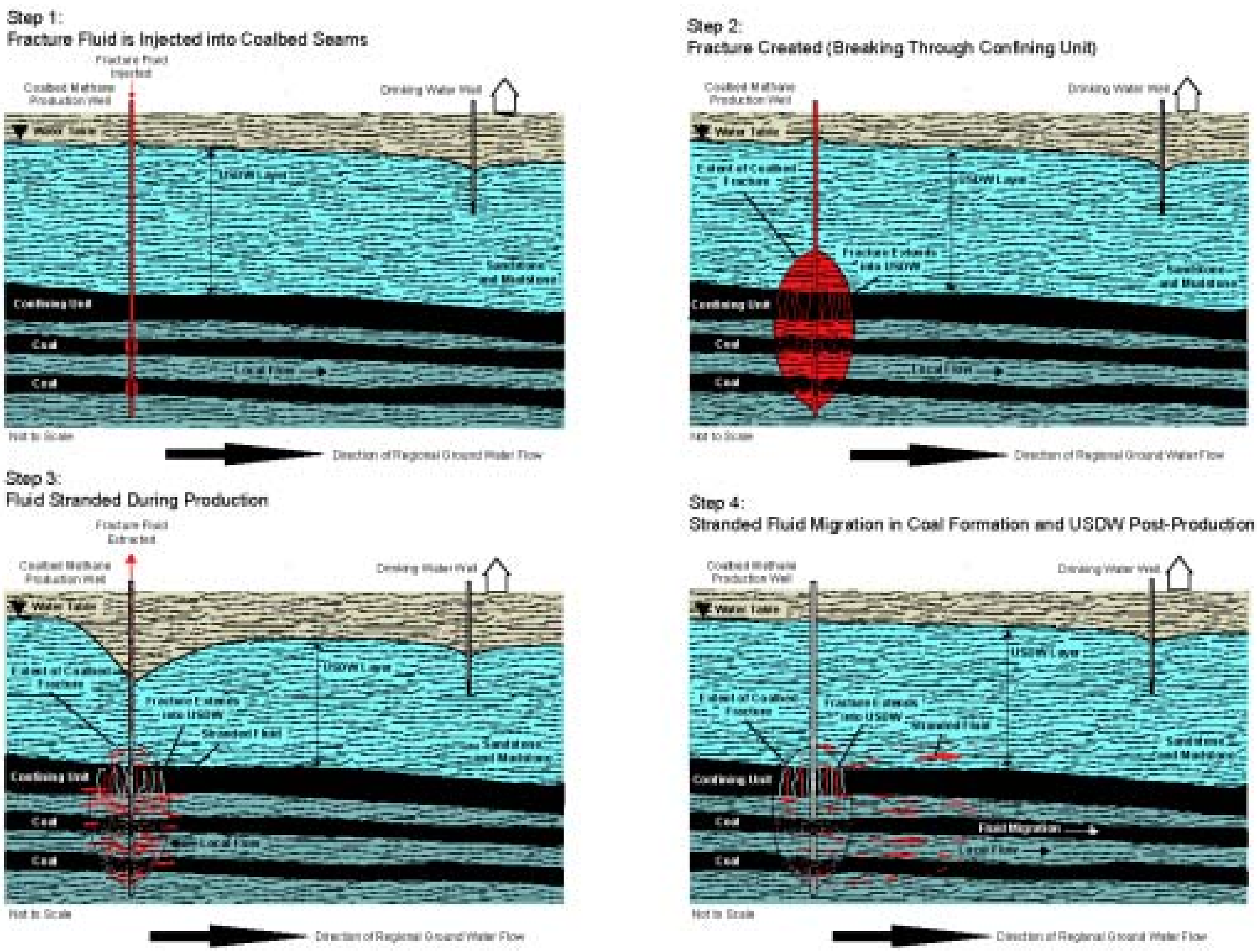


Figure 1-3. Hypothetical Mechanism - Fracture Creates Connection to USDW



Chapter 2
Study Methodology

This chapter outlines EPA's approach for completing Phase I of the study. This chapter describes the development of the study, the information collection and review process that EPA used, and the internal and external review process for the report.

2.1 Overview of the Study Methods

EPA developed the Phase I study methodology to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into coalbed methane wells, and to determine, based on these findings, whether further study is warranted.

On July 25, 2000, EPA published a *Federal Register* notice (65 FR 45774 (USEPA, 2000)) requesting comment on a conceptual study design in order to receive stakeholder input on how an EPA study should be structured. On August 24, 2000, EPA held a public meeting to obtain additional stakeholder input on the proposed study design. EPA received more than 80 sets of comments from industry, state oil and gas agencies, environmental groups, and individual citizens in response to the *Federal Register* notice and public meeting. A summary of these comments can be viewed on EPA's Web site at www.epa.gov/safewater/uic/cbmstudy.

EPA revised its study approach in response to the comments it received on the conceptual study design. The final study design, "Study Design for Evaluating the Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs", was released in April 2001 and is available on the website referenced above. One significant change in the final study design was EPA's decision to complete the study in a phased approach to efficiently address the stated project objectives. This phased approach, similar in design to that used in other complex studies, would allow EPA to use information gained in one phase to focus on the need for, and direction of, subsequent phases.

Phase I of the study was intended as a limited-scope assessment that would enable the Agency to determine if hydraulic fracturing of coalbed methane wells clearly poses little or no threat to USDWs, or if the practice may pose a threat. In Phase I, EPA:

- Gathered existing information to review hydraulic fracturing processes, practices and settings;
- Requested public comment to identify incidents that had not been reported to EPA; and
- Reviewed reported incidents of groundwater contamination and any follow-up

actions or investigations by other parties (state or local agencies, industry, academia, etc.).

In addition, as recommended by commenters, EPA decided to compile accounts of personal experiences with coalbed methane impacts on drinking water wells. These experiences are summarized in Chapter 6.

In its final study design, EPA indicated that the Agency would make a determination regarding whether further investigation was needed after analyzing the Phase I information. Specifically, EPA determined that it would not continue into Phase II of the study if the investigation found that no hazardous constituents were used in fracturing fluids, hydraulic fracturing did not increase the hydraulic connection between previously isolated formations, *and* reported incidents of water quality degradation could be attributed to other, more plausible causes.

EPA identified two possible mechanisms by which hydraulic fracturing fluid injection into coalbed methane wells could potentially affect the quality of USDWs:

1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

To determine if contamination might occur through either mechanism, EPA collected information on:

1. Hydraulic fracturing practices.

2. Hydraulic fracturing fluids and additives to determine whether these substances contain hazardous constituents.

3. The hydrogeology of the coalbed methane basins, including the identification of coal seams that are located in USDWs.

4. Water quality incidents potentially associated with hydraulic fracturing.

EPA anticipated that sufficient information would be available to evaluate the impacts of direct injection into USDWs because the main considerations are the location of the coal formations relative to USDWs and the chemical constituents in hydraulic fracturing fluids. The Agency further anticipated that documenting USDW impacts via the creation of a hydraulic connection between the coalbed formation and adjacent USDW(s) would be more difficult. This is because more detailed, site-specific, geological information or data for specific fracturing events needed to definitively document such a hydraulic communication are not readily available. Site-specific data include:

- Water quantity and quality conditions in a USDW (or a well) both before and after a fracturing event;
- Location, dimensions, and conductivity of fractures created during the coalbed stimulation event;
- Measured changes in groundwater flow between the USDW and coalbeds or other aquifers; and
- Impacts of other, unrelated, hydrologic and water quality processes that could also be affecting the USDW.

2.2 Information Sources

EPA obtained available literature and information through:

- Literature reviews.
- Coordination with DOE.
- Interviews with companies that perform hydraulic fracturing and interviews with citizens, local and state authorities, the Bureau of Land Management and EPA Region 8 personnel.
- Field visits.
- Responses to EPA's *Federal Register* request (66 FR 39396 (U.S. EPA, 2001)) for information on incidents of groundwater contamination believed to be associated with hydraulic fracturing of coalbed methane wells.

EPA researched more than 200 peer-reviewed publications, interviewed approximately 50 employees from industry and state or local government agencies, and communicated with approximately 40 citizens and groups who are concerned that CBM production affected their drinking water wells.

The procedure that EPA used to obtain information from each of these sources is discussed in more detail below. A copy of the quality assurance protocol that EPA employed to verify all the sources of data used to write this report is provided as Appendix B.

2.2.1 Literature Reviews

EPA conducted a review of existing literature and information on hydraulic fracturing for coalbed methane production. The focus of the literature review was to obtain information on topics 1 through 3 listed in Section 2.1, above.

The degree to which information was available for each of the 11 coalbed basins in the report was variable. The amount of information available depended on the extent of exploration and production in each basin.

EPA conducted an extensive literature search, using the Engineering Index and GeoRef on-line reference databases, for abstracts from technical articles, books, and proceedings. EPA also conducted Internet-based searches to locate additional information using relevant Web sites located using various search engines, including Google™, Yahoo®, and Alta Vista®. EPA used specialized search engines, such as those provided on state geological survey Web sites and by the Gas Technology Institute (GTI) for specific queries. All relevant Web sites were logged in project books and referenced in this report when cited.

EPA conducted these literature searches by subject topics and using the following key words, either separately or in combination: coal basin, coalbed methane, cross-linked gel, fracturing fluid additives, fracturing fluid technology, fracturing fluid performance, fracturing fluids, ground water, hydraulic fracturing, hydraulic fracture dimension, hydraulic fracture growth, hydrology, linear gel, methane gas production, nitrogen foam, underground sources of drinking water, and USDWs. EPA printed, catalogued, and surveyed all results of searches for pertinent journal articles, books, and conference proceedings containing information that might meet the specific data needs of this report.

EPA acquired most of the pertinent articles, which were identified from the Engineering Index and GeoRef on-line reference databases, from the University of Texas Library in Austin because this library's holdings include an extensive collection of publications related to oil and gas production. EPA researched references from the University of Texas documents and acquired those documents that were relevant to the study. Only a small fraction of the pertinent articles, specifically proprietary articles and articles published for overseas conferences were unavailable. EPA also acquired articles from GTI. EPA has archived, by topic, all papers collected for the study.

To verify key information extracted from the literature, EPA contacted by phone relevant organizations such as state regulatory agencies, state geological surveys, natural gas companies, GTI, and service companies. The Agency used telephone logs to document all communications. Personal conversations with the employees of the various organizations yielded additional information in the form of reports, figures, and maps, as well as statements based on best professional judgment and experience. These were collected, documented, and referenced in conjunction with the literature identified in the literature searches. The majority of the literature pertaining to coalbed methane basins and hydraulic fracturing was written in the early to mid 1990s. According to the Texas Bureau of Economic Geology (TBEG) (personal communication, TBEG Staff, 2000), this period of intense activity was a result of the emphasis placed on gas exploration by the Section 29 Tax Credit of the Crude Oil Windfall Profit Tax Act of 1980 and research grants to industry, academia, and government agencies. The Section 29 credit does not, however, apply to coal gas wells drilled after December 31, 1992.

2.2.2 Department of Energy

EPA reviewed information from DOE's "White Paper" on hydraulic fracturing practices. This paper addresses the following topics:

- Objectives of hydraulic fracturing.
- How candidate wells are selected for hydraulic fracturing.
- How fracture treatments are designed.
- Field operation considerations.
- Physics of fracture formation in coalbeds.
- Fracturing fluids.
- Stimulation techniques used for developing coalbeds.
- Instrumentation/methods for tracking fractures.

The complete DOE paper is included as Appendix A, and excerpts from this paper are included in Chapter 3, Characteristics of Coalbed Methane Production and Associated Hydraulic Fracturing Practices.

2.2.3 Interviews

EPA contacted hydraulic fracturing service companies including BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation, as well as a fracturing fluids producer, Hercules, Inc., to obtain information regarding the content of hydraulic fracturing fluids and additives they use or manufacture. Two companies, Halliburton and Schlumberger, provided EPA with material safety data sheets (MSDSs) for several hydraulic fracturing fluids and additives. The MSDSs were reviewed to determine the nature of the constituents in fracturing fluids used to stimulate coalbed methane production. These topics are discussed in Chapter 4, Hydraulic Fracturing Fluids.

EPA also evaluated reports from individuals and organizations that are concerned that their drinking water supplies were affected by hydraulic fracturing. These reported personal experiences came from Colorado, New Mexico, Wyoming, Alabama, and Virginia. In response to these reports, EPA conducted telephone interviews with citizens, local and state authorities, the Bureau of Land Management and EPA Region 8 personnel. EPA also evaluated state agency responses to any complaints received by EPA or state agencies. The Agency also evaluated the available data to determine whether there is sufficient information to reveal the source of the alleged water quality contamination.

2.2.4 Field Visits

EPA conducted field visits in Colorado, Kansas, and Virginia to better understand how local coalbed methane production activities may vary from basin to basin. In addition, during the field visits, EPA was able to meet with concerned local citizens and state agencies to discuss coalbed methane production issues. A summary of these field visits is outlined below.

In August 2000, EPA met with a group of concerned citizens, officials from the Colorado Oil and Gas Conservation Commission, and representatives of the La Plata County government. EPA witnessed a fracturing event, reviewed records including temperature logs of past fracturing events conducted on coalbed methane wells, and performed a reconnaissance of the area allegedly affected by coalbed methane production.

In August 2001, EPA met with the Virginia Department of Mines, Minerals and Energy, the agency that regulates the coalbed methane production industry in Virginia. The Department provided information about the state's investigation of water quality incidents potentially associated with coalbed methane production in the Central Appalachian Valley. The Department also submitted water quality incident reports for review by EPA. During this visit, EPA met with concerned citizens in Virginia. Citizens groups from Buchannan and surrounding counties were invited to meet with EPA and DOE staff to discuss water quality issues believed to be related to local hydraulic fracturing of coalbed methane wells. Notes from the meeting are referenced in Chapter 6.

EPA also organized a field visit with Consol Energy, Inc. and Halliburton to witness a hydraulic fracturing event. Halliburton performed a hydraulic fracture job on a coalbed methane well in western Virginia using equipment, fracturing fluids, and techniques, which are typical of those described in the literature. EPA was able to observe the fracturing process and collect information, including MSDSs from the service company and gas company engineers. The information from this field visit was used to supplement the data on hydraulic fracturing fluids in Chapter 4.

In November 2001, EPA witnessed a fracturing event in Wilson County, Kansas, to gain a better understanding of the regional geology and hydraulic fracturing practices in the area. In attendance were Colt Energy (the well operator); Consolidated Industrial Services, Inc. (the service company conducting the fracture job); and two state agencies, the Kansas Corporation Commission, and the Missouri Department of Natural Resources. MSDSs for fracturing fluids typically used in the area were also provided to EPA by the Kansas Corporation Commission.

2.2.5 Federal Register Notice to Identify Reported Incidents

EPA provided an opportunity for the public to submit information on any impacts to groundwater believed to be associated with hydraulic fracturing through a request for public comment (66 FR 39396 (USEPA, 2001)). EPA also sent copies of the *Federal Register* notice with a cover letter to county-level public health and/or environmental officials in counties that may be producing coalbed methane. In addition, letters were sent to stakeholders informing them that the *Federal Register* notice had been published. Responses to the *Federal Register* notice are available at EPA's water docket (docket number W-01-09; Water Docket (MC 4101); Rm EB 57; U.S. Environmental Protection Agency; 1200 Pennsylvania Avenue, NW; Washington, DC 20460; phone number: (202) 566-2426). A summary of the comments is provided in Chapter 6.

2.3 Review Process

This report has benefited from a series of internal and external technical reviews. EPA verified information through telephone interviews with state and local officials, as well as through the Agency's internal quality assurance process. EPA conducted a quality assurance review of the data collection procedures as well as a review of the individual literature sources cited in the report. In addition, more than nine EPA offices reviewed and commented on the draft report. Other federal agencies that reviewed the draft report included DOE and the U.S. Geological Survey (USGS).

In 2001, EPA also submitted the draft report to a scientific peer-review panel consisting of experts from industry, academia, and government agencies. The panel's task was to review the draft report and provide comments on the descriptions and conclusions developed by EPA. The panel also provided information about additional data sources to supplement those used in the report. Following receipt of comments on the draft report, EPA made the appropriate changes to the document prior to its publication and release.

EPA made the report available for public comment by an announcement in the *Federal Register* on August 28, 2002 (67 FR 55249 (USEPA, 2002)). The 60-day public comment period officially ended on October 28, 2002. The Agency received and reviewed comments from 105 commenters and incorporated many of these comments into this final Phase I report. A summary of the public comments and EPA's responses is provided in, "Public Comment and Response Summary for the Study on the Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water" (EPA 816-R-04-004), available on EPA's electronic docket.

Chapter 3
Characteristics of Coalbed Methane Production and Associated Hydraulic Fracturing Practices

Understanding the practice of hydraulic fracturing as it pertains to coalbed methane production is an important first step in evaluating its potential impacts on the quality of USDWs. This chapter presents the following: an overview of the geologic processes leading to coal formation, an overview of coalbed methane production practices, a discussion of fracture behavior, a review of the literature on the use and recovery of fracturing fluids, a discussion of mechanisms affecting fluid recovery, and a summary of the methods used for measuring and predicting fracture dimensions and fracturing fluid movement. In addition, several diagrams have been included at the end of this chapter to help illustrate many of these topics. Specifically, Figures 3-1 through 3-8 show the location of the coal basins, the geography of a peat-forming system, the geometry of natural cleats and hydraulically induced fractures, an overview of the hydraulic fracturing process, the relationship between water and gas production rates, and side and plan views of vertical hydraulic fractures.

3.1 Introduction

Coalbed methane is a gas formed as part of the geological process of coal generation, and is contained in varying quantities within all coal. Coalbed methane is exceptionally pure compared to conventional natural gas, containing only very small proportions of "wet" compounds (e.g., heavier hydrocarbons such as ethane and butane) and other gases (e.g., hydrogen sulfide and carbon dioxide). Coalbed gas is over 90 percent methane, and is suitable for introduction into a commercial pipeline with little or no treatment (Rice, 1993; Levine, 1993).

From the earliest days of coal mining, the flammable and explosive gas in coalbeds has been one of mining's paramount safety problems. Over the centuries, miners have developed several methods to extract the coalbed methane from coal and mine workings. Coalbed methane well production began in 1971 and was originally intended as a safety measure in underground coalmines to reduce the explosion hazard posed by methane (Elder and Deul, 1974).

In 1980, the United States Congress enacted a tax credit for "Non-conventional energy production." In 1984, there were only several hundred coalbed methane wells in the United States and most were used for mine de-methanization. By 1990, the anticipated expiration of the tax credit contributed to a dramatic increase in the number of coalbed methane wells nationwide. In addition, DOE and GTI supported extensive research into coalbed exploration and production methods. Federal tax credits and State Severance Tax exemptions served to subsidize the development of coalbed methane resources (Soot, 1991; Pashin and Hinkle, 1997). The federal tax credits and incentives expired at the end of 1992, but coalbed methane exploration, development, and reserves have remained stable or increased (Stevens et al., 1996). At the end of 2000, coalbed methane production from 13 states totaled 1.353 trillion cubic feet, an increase of 156 percent from 1992. During 2000, a total of 13,973 coalbed methane wells were in production (GTI; EPA Regional Offices, 2001). By the end of 2000, coalbed methane production accounted for about 7 percent of the total United States dry gas production and 9 percent of proven dry gas reserves (EIA, 2001).

Coal is defined as a rock that contains at least 50 percent organic matter by weight. The precursor of coal is peat, plant matter deposited over time in fresh-water swamps associated with coastal deltaic rivers. The coal resources from which coalbed methane is derived have similar geologic origins. In the United States, they are usually found in geologic formations that are approximately 65-325 million years old. Coal formation occurred during a time of moderate climate and broad inland oceans. Sea level rose and fell in conjunction with tectonic forces (i.e., subsidence and uplift of land masses) and melting/freezing cycles of decreases and increases in the polar ice masses. As a result, coastal environments such as coastal deltas and peat swamps migrated landward when sea levels rose and moved seaward when sea levels fell, marked by cycles of submergence and emergence. With these cycles of rising and falling sea levels, what was a peat swamp at one time would later be under 100 feet of water. The cycle of sea level rising and falling is marked in the geologic record as cycles of inter-layered deep and shallow water sediments.

The type of sediments deposited at a given location varied with the depth of submergence (Figure 3-2). Generally, carbon-rich organic plant matter was deposited in shallow peat swamps, sand was deposited along beaches and other near-shore, shallow marine environments, and silts and clays and calcium-rich muds were deposited further off-shore in deeper marine environments. Subjected to high pressure over considerable time (due to burial under subsequent sediments), the peats were transformed into coal, the sand into sandstone, the silts and clays into shales, siltstones, and mudstones, and the calcium-rich muds were transformed into limestones. These coal-bearing inter-layered sedimentary sequences are sometimes referred to as “coal cycles.” The idealized coal cycle consists of repeated sequences of very fine-grained sediments (shales and limestones) overlain by coarser sediments (siltstones and sandstones), and then capped by coal. The sequence repeats with shales and limestones over the coal, followed by siltstones and sandstones, then more coal, and so on. Sometimes certain formations are missing from the sequences, so coal is often, though not always, overlain by shales and limestones.

The sedimentation patterns in these fluctuating coastal environments over geologic time scale determined the presence, thickness, and geometry of present-day coalbeds. The number of coal cycles determines the number of resulting coalbeds. For example, the Black Warrior Basin of Alabama includes up to 10 cycles, whereas the San Juan Basin (New Mexico and Colorado) contains as few as 3. The short, rising and falling sea level cycles reflected in the Black Warrior Basin geology produced many thin coalbeds, ranging from less than 1 inch to as much as 4 feet thick (Carrol et al., 1993; Pashin, 1994a and 1994b), whereas the stable, long-term cycles of the San Juan Basin produced fewer, but thicker coalbeds, with single coalbeds up to 70 feet thick (Kaiser and Ayers, 1994).

Peat is transformed into coal when it is buried by accumulating sediment and heated in the subsurface over geologic time. The "rank" of coal describes the amount of energy (measured in British thermal units or Btus) it contains, and is a function of the proportion and type of organic matter, the length and temperature of burial, and the influences of subsequent hydrogeologic and tectonic processes (Carrol et al., 1993; Levine, 1993; Rice, 1993). Methane is generated as part of the process whereby peat is transformed into coal. The origin of methane in coal of low rank, such as bituminous coal, is primarily biogenic (i.e., the result of bacterial action on organic matter) (Levine 1993, as cited by the Alabama Oil and Gas Board, 2002). Low rank coals tend to have lower gas content than high rank coals such as anthracite. Anthracite can have extremely high gas content, but the gas tends to desorb so slowly that anthracite is an insignificant source of coalbed methane (Levine, 1993, as cited by the Alabama Oil and Gas Board, 2002). Commercial coalbed methane production takes place in coals of mid-rank, usually low- to high-volatile bituminous coals (Levine, 1993; Rice, 1993).

A network of fractures, joints, and a sub-network of small joints called cleats commonly characterize the physical structure of coalbeds. Joints are larger, systematic, near-vertical fractures within the coal, generally spaced from several feet to several dozen feet apart (Close, 1993; Levine, 1993). There are two types of cleats: the primary, more continuous cleats are called *face cleats*, while the abutting cleats are called *butt cleats* (Laubach and Tremain 1991; Close, 1993; Levine, 1993) (Figure 3-3). The butt cleats appear as the rungs on a ladder that are bounded on each side by the face cleats. The spacing between cleats is often roughly proportional to the thickness of coal cut by the cleats; thin coals have more closely spaced cleats and thick coals more widely spaced cleats (Laubach et al., 1998, as cited by Olson, 2001).

The primary (or natural) permeability of coal is very low, typically ranging from 0.1 to 30 millidarcies (md) (McKee et al., 1989). According to Warpinski (2001), because coal is a very weak (low modulus) material and cannot take much stress without fracturing, coal is almost always highly fractured and cleated. The resulting network of fractures commonly gives coalbeds a high secondary permeability (despite coal's typically low primary permeability). Groundwater, hydraulic fracturing fluids, and methane gas can more easily flow through the network of fractures. Because hydraulic fracturing generally enlarges pre-existing fractures and rarely creates new fractures (Steidl, 1993; Diamond, 1987a and b; Diamond and Oyler, 1987), this network of natural fractures is very important to the extraction of methane from the coal.

3.2 Hydraulic Fracturing

This section provides an overview of the hydraulic fracturing process, and the factors that affect fracture behavior and fracture orientation. Figure 3-4 provides a simplified graphical representation of a hypothetical hydraulic fracturing event in a coalbed methane well. This diagram shows the fracture initiation and propagation stages, as well as the proppant placement and fracturing fluid recovery stages. Only horizontal fractures are shown in this diagram, although hydraulically induced fractures are often vertically oriented.

3.2.1 The Hydraulic Fracturing Process

Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of oil and coalbed methane wells. The extraction of coalbed methane is enhanced by hydraulically enlarging and/or creating fractures in the coal zones. The resulting fracture system facilitates pumping of groundwater from the coal zone, thereby reducing pressure and enabling the methane to be released from the coal and more easily pumped through the fracture system back to the well (and then through the well to the surface). To initiate the process, a production well is drilled into the targeted coalbeds. Fracturing fluids containing proppants are then injected under high pressure into the well and specifically into the targeted coalbeds in the subsurface.

The fracturing fluids are injected into the subsurface at a rate and pressure that are too high for the targeted coal zone to accept. As the resistance to the injected fluids increases, the pressure in the injecting well increases to a level that exceeds the breakdown pressure of the rocks in the targeted coal zone, and the rocks "breakdown" (Olson, 2001). In this way, the hydraulic fracturing process "fractures" the coalbeds (and sometimes other geologic strata within or around the targeted coal zones). This process sometimes can create new fractures, but most often opportunistically enlarges existing fractures, increasing the connections of the natural fracture networks in and around the coalbeds (Steidl 1993; Diamond 1987a and b; Diamond and Oyler, 1987). The pressure-induced fracturing serves to connect the network of fractures in the coalbeds to the hydraulic fracturing well (which subsequently will serve as the methane extraction or production well). The fracturing fluids pumped into the subsurface under high pressure also deliver and emplace the "proppant." The most common proppant is fine sand; under pressure, the sand is forced into the natural and/or enlarged fractures and acts to "prop" open the fractures even after the fracturing pressure is reduced. The increased permeability due to fracturing and proppant emplacement facilitates the flow and extraction of methane from coalbeds.

Methane within coalbeds is not structurally "trapped" by overlying geologic strata, as in the geologic environments typical of conventional gas deposits. Only about 5 to 9 percent of the coalbed methane is present as "free" gas within the joints and cleats of coalbeds. Most of the coalbed methane is contained within the coal itself (adsorbed to the sides of the small pores in the coal) (Koenig, 1989; Winston, 1990; Close, 1993).

Before coalbed methane production begins, groundwater and injected fracturing fluids are first pumped out (or "produced" in industry terminology) from the network of fractures in and around the coal zone. The fluids are pumped until the pressure declines to the point that methane begins to desorb from the coal (Gray, 1987).

Coalbed methane production initially requires pumping and removing significant amounts of water to sufficiently reduce the hydrostatic pressure in the subsurface so that methane can desorb from the coal before methane extraction can begin. Coalbed methane is produced at close to atmospheric pressure (Ely et al., 1990; Schraufnagel, 1993). The proportion of water to methane pumped is initially high and declines with increasing coalbed methane production (Figure 3-5). In contrast, in the production of conventional petroleum-based gas, the production of gas is initially high, and as gas production continues over time and the gas resources are progressively depleted, gas production decreases and the amount of water pumped increases.

Almost every coalbed targeted for methane production must be hydraulically fractured to connect the production well bore to the coalbed fracture network (Holditch et al., 1988). Although the general hydraulic fracturing process (described above) is generally similar across the country, the details of the process can differ significantly from location to location depending on the site-specific geologic conditions. For example, although most hydraulic fracturing wells are completely cased except for openings at the targeted coal zone, many wells in the San Juan Basin are fractured by creating a cavity in the open-hole section. Also, in contrast to the typical fracturing job, many wells in the Black Warrior Basin are stimulated more than once. Here, when wells are open to multiple coal seams, the hydraulic fracturing process may involve several or multiple fracturing events, using from 2 to 5 hydraulic fracture treatments per well (depending on number of seams and spacing between seams). Many coalbed methane wells are re-fractured at some time after the initial treatment in an effort to re-connect the wellbore to the production zones to overcome plugging or other well problems (Holditch, 1990; Saulsberry et al., 1990; Palmer et al., 1991a and 1991b; Holditch, 1993). Also, in response to site-specific coal geology and the economics of coalbed methane production where coal seams are thin and vertically separated by up to hundreds of feet of intervening rock) operators might design fracture treatments to enhance the vertical dimension and perform several fracture treatments within a single well to produce methane in an economically viable fashion, (Ely, et al., 1990; Holditch, 1990; Saulsberry et al., 1990; Spafford, 1991; Holditch, 1993).

3.2.2 Factors Affecting Fracture Behavior

Fracture behavior is of interest because it contributes to an understanding of the potential impact of fracturing fluid injection on USDWs; the opportunities for fracture connections within or into a USDW are affected by the extent to which a hydraulically induced fracture grows. Specifically, when hydraulic fracturing fluids are injected into formations that are not themselves USDWs, the following scenarios are of potential concern:

- The hydraulically induced fracture may extend from the target formation into a USDW.

- The hydraulically induced fracture may connect with natural (existing) fracture systems and/or porous and permeable formations, which may facilitate the movement of fracturing fluids into a USDW.

Fracture behavior through coal and other geologic formations commonly present above and below coalbeds depends on site-specific factors such as the following:

1. Physical properties, types, thicknesses, and depths of the targeted coalbeds as well as those of the surrounding geologic formations.

2. Presence of existing natural fracture systems and their orientation in the coalbeds and surrounding formations.

3. Amount and distribution of stress (i.e., in-situ stress), and the stress contrasts between the targeted coalbeds and surrounding formations.

4. Hydraulic fracture stimulation design including volume of fracturing fluid injected into the subsurface as well as the fluid injection rate and fluid viscosity.

Many of these factors are interrelated and together will influence whether and how far hydraulic fractures will propagate into or beyond coalbeds targeted for fracturing. These factors are discussed below.

Properties of Coalbeds and Surrounding Formations

Coalbed depth and rock types in the coal zone have important fundamental influences on fracture dimensions and orientations. According to Nielsen and Hansen (1987, as cited in Appendix A: DOE, Hydraulic Fracturing), generally, at depths of less than 1,000 feet, the direction of least principal stress tends to be vertical and, therefore, at these relatively shallow depths fractures typically have more of a horizontal than a vertical component. Here, horizontal fractures tend to be created because the hydraulically induced pressure forces the walls of the fracture to open in the direction of least stress (which is vertical), creating a horizontal fracture. At these shallower depths, the horizontal fractures result from the low vertical stress due to the relatively low weight of overlying geologic material (due to the shallow depth). Shallow vertical fractures are most likely due to the presence of natural (existing) vertical fractures, from which hydraulically induced vertical fractures can initiate. Generally, in locations deeper than 1,000 feet, the least principal stress tends to be horizontal so vertical fractures tend to form. Vertical fractures created in these greater depths can propagate vertically to shallower depths and develop a horizontal component (Nielsen and Hansen, 1987 as cited in Appendix A: DOE, Hydraulic Fracturing). In the formation of these "T-fractures," the fracture tip may fill with coal fines or intercept a zone of stress contrast, causing the fracture to turn and develop horizontally, sometimes at the contact of the coalbed and an overlying formation.

In many coalbed methane basins, the depths, lithologic properties, and stress fields of the coal zones result in hydraulic fractures that are higher than they are long ("length" refers to horizontal distance from the well bore) (Diamond, 1987a; Morales et al., 1990; Zuber et al., 1990; Holditch et al., 1989; Palmer and Sparks, 1990; Jones and Schraufnagel, 1991; Steidl, 1991; Wright, 1992; Palmer et al., 1991a and 1993a). Almost all of the sites studied by Diamond (1987a and b) had vertical fractures, and about half had horizontal fractures.

Naceur and Touboul (1990) state that the primary mechanisms controlling fracture height are contrasts in the physical properties of the rock strata within and surrounding the coal zone being fractured. Contrasts in strata stresses, moduli, leakoff, and toughness affect fracture growth, with stress contrasts being the most important mechanism controlling fracture height (Naceur and Touboul 1990). (Stress is discussed in more detail later in this section.) Moduli are the ratios of stress to strain in various formations. Leakoff is the magnitude of pressure exerted on a formation that causes fluid to be forced into the formation. The fluid may be flowing into the pore spaces of the rock or into cracks opened and propagated into the formation by the fluid pressure. Toughness can be defined as the point at which enough stress intensity has been applied to a rock formation, so that a fracture initiates and propagates. Coal is generally very weak (with low modulus) and easily fractures. Siltstones, sandstones, and mudstones (other rock types commonly occurring in coal zones) tend to have higher moduli, greater toughness and fracture less easily (Warpinski, 2001). Thick shales, which commonly overlie coalbeds, often act as a barrier to fracture growth (see Appendix A).

Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, highly cleated coal seams will prevent fractures from growing vertically. When the fracturing fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam (see Appendix A).

The low permeability of relatively unfractured shale may help to protect USDWs from being affected by hydraulic fracturing fluids in some basins. If sufficiently thick and relatively unfractured shales are present, they may act as a barrier not only to fracture height growth, but also to fluid movement. The degree to which any formation overlying targeted coalbeds will act as a hydraulic barrier will depend on site-specific factors.

The lithology of coalbeds and surrounding formations is variable in the basins where coalbed methane is produced. Although common, the idealized coal cycle (with shales overlying coalbeds) is not always present in all coal basins or necessarily in all parts of any basin. Although Holditch (1993) states that fracture heights can grow where the coal seam is bounded above or below by sandstone, Warpinski (2001) states that highly layered formations or very permeable strata, such as some sandstones, can act to inhibit fracture growth. Some of the coal seams of the San Juan Basin are bounded below by sandstone. In some locations in each of the other basins, coalbeds are underlain by, overlain by, or interbedded with sandstones. Additional detail on the stratigraphy within each basin is provided in the attachments to this study.

Differences in fracture behavior may also be due in part to very small (but influential) layers or irregularities that exist in the rocks as part of the sedimentation process that created them. Therefore, a valid measurement of rock properties relevant to fracture behavior at one location may not adequately represent the properties of similar rock at another location (Hanson et al., 1987; Jones et al., 1987a and 1987b; Palmer et al., 1989; Morales et al., 1990; Naceur and Touboul, 1990; Jones and Schraufnagel, 1991; Palmer et al., 1993b; Elbel, 1994). For example, the presence of a shallow clay layer as thin as 10 millimeters at the upper contact of a coal seam can cause a vertically propagating, shallow hydraulic fracture to "turn" horizontal and fail to penetrate the next overlying coal seam (Jones et al., 1987a; Palmer et al., 1989; Morales et al., 1990; Palmer et al., 1991b and 1993b). In other cases, hydraulic fractures may penetrate into or even, as shown in the case of some thin shales, completely through overlying shale layers (Diamond, 1987a and b; Diamond and Oyler, 1987). Warpinski et al. (1982) found that even microscopically-thin ash beds can influence hydraulic fracture propagation. In other words, the site-specific geology can play a key role in influencing fracture behavior. In addition to the effects of the rock type and sometimes even thin layers within strata, natural fractures also play a role in fracture behavior and fracture propagation.

Natural Fracture Systems

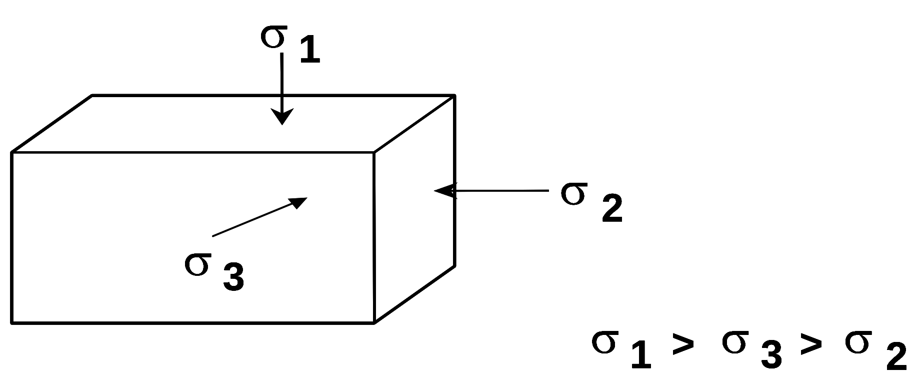
Steidl (1993), based on his "mined-through" studies, concluded that high coalbed methane production depends greatly on the presence of pre-existing natural fracture systems. Hydraulic fracturing tends to widen naturally occurring planes of weakness and rarely creates new fractures, as based on observations by Diamond (1987a and b) and Diamond and Oyler (1987) in their mined-through studies. ("Mined-through" studies provide unique subsurface access to investigate coalbeds and surrounding rock after hydraulic fracturing. Mined-through studies are reviewed in more detail in section 3.4.1.) Diamond and Oyler (1987) also noted that this opportunistic enlarging of preexisting fractures appears to account for those cases where hydraulic fractures propagate from the targeted coalbeds into overlying rock, and their studies found penetration into overlying layers in nearly half of the fractures intercepted by underground mines.

Importantly, in several locations in the Diamond (1987a and b) study sites, fluorescent paint was injected along with the hydraulic fracturing fluids and the paint was found in natural fractures from 200 to slightly more than 600 feet beyond the sand-filled ("propped") portions of hydraulically induced or enlarged fractures. This suggests that the induced/enlarged fractures link into the existing fracture network system and that hydraulic fracturing fluids can move beyond, and sometimes significantly beyond, the propped, sand-filled portions of hydraulically induced fractures (Steidl 1993; Diamond 1987a and b; Diamond and Oyler, 1987). The mined-through studies did not conduct systematic assessments of the extent of the fractures into or through the roof rock shales that were immediately above the mined coal (the rock strata immediately above a mined coal layer is referred to as the "roof rock").

In-Situ Stress and Stress Contrasts

In-situ stress and the relative stress of neighboring geologic strata are important influences on fracture behavior. A discussion of in-situ stress is provided in DOE's paper "Hydraulic Fracturing" (provided as Appendix A). In-situ stress is described as:

> "Underground formations are confined and under stress… [The graphic below] illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses… [In the graphic below,] σ_1 is the vertical stress, σ_2 is the maximum horizontal stress, while σ_3 is the minimum horizontal stress, where $\sigma_1>\sigma_2>\sigma_3$. This is a typical configuration for coalbed methane reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ_2) or minimum stress (σ_3). These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production."



Local in-situ stress at depth.

According to (Naceur and Touboul 1990), the contrast in stress between adjacent rock strata within and surrounding the targeted coal zone is the most important mechanism controlling fracture height. Stress contrast is important in determining whether a fracture will continue to propagate in the same direction when it hits a geologic contact between two different rock types. Often, a high stress contrast results in a barrier to fracture propagation. An example of this would be where there is a geologic contact between a coalbed and an overlying, thick, higher-stress shale.

Hydraulic Fracture Stimulation Design

The procedures and fracturing fluids used to stimulate coalbed methane wells can differ from operator to operator in a single basin due to local characteristics of geology and depth and to perceived advantages of cost, effectiveness, production characteristics, or other factors. On a larger scale, although fracture stimulations in coalbed methane projects in different basins may share common rock types and characteristics, fracture behavior can differ significantly. Discussions on hydraulic fracturing practices in 11 individual coal basins are included in Chapter 5 and in Attachments 1 through 11.

Aspects of fracture behavior, such as fracture dimensions (height, length, and width), are affected by the different fracturing approaches taken by the operator during a hydraulic fracturing event. Generally, the larger the volume of fracturing fluids injected, the larger the potential fracture dimensions. Fluid injection rates and viscosity can also affect fracture dimensions (Olson, 2001; Diamond and Oyler, 1987). Large injection volumes also often result in extensive networks of induced fractures. Gelled water treatments may result in the widest and longest fractures, but this occurrence cannot be concluded with certainty from the mined-through studies (Diamond and Oyler, 1987; Diamond 1987a and b).

The effects of these operator-controlled actions interact with and are influenced by the physical properties, depths, and in-situ stress of the geologic formations being fractured (as listed above). For example, if a hydraulically induced fracture has a relatively constant height due to a geologic layer acting as a barrier to fracture propagation, and the fracture is forced to grow and increase in volume (through an increased volume of fracturing fluid), the fracture will mainly grow in length. Also, increasing fluid viscosity can increase the pressure due to injection, resulting in greater fracture width, and thus often shorter fractures (Olson, 2001).

3.3 Fracturing Fluids

The fluids used for fracture development are pumped at high pressure into the well. They may be "clear" (most commonly water, but may include acid, oil, or water with friction-reducer additives) or "gelled" (viscosity-modified water, using guar or other gelling agents). Some literature indicates that coalbed fracture treatments use from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant (Holditch et al., 1988 and 1989; Jeu et al., 1988; Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991b, 1993a, and 1993b). More typical injection volumes, based on average injection volume data provided by Halliburton for six coalbed methane locations, indicate a maximum average injection volume of 150,000 gal/well and a median average injection volume of 57,500 gal/well (Halliburton, Inc., 2003).

Depending on the basin and treatment design, the composition of these fluids varies significantly, from simple water and sand to complex polymeric substances with a multitude of additives. Types of fracturing fluids are discussed in greater detail in Chapter 4.

3.3.1 Quantifying Fluid Recovery

Several studies have evaluated the recovery rates of hydraulic fracturing treatment fluids in coal and non-coal formations as discussed in more detail below. Non-coal formations were evaluated to augment the available flowback data.

Coal Formation

Palmer et al. (1991a) measured flowback rates in 13 hydraulic fracturing wells to compare the gas production resulting from the use of water versus gel-based fracturing fluids. This study was conducted in a coal seam with permeabilities from 5 to 20 md. Ten samples collected over a 19-day flowback period indicated a recovery rate of 61 percent. Palmer et al. (1991a) predicted total recovery to be from 68 percent to as much as 82 percent.

Non-Coal Formations

Willberg et al. (1997) conducted a flowback analysis in 10 wells in a heterogeneous sandstone and shale environment that was highly impermeable (i.e., with a permeability of 0.01 md). The fluids used in this study were recovered at an average efficiency of 35 percent during the 4 to 5 day flowback period. Three wells were then sampled every 4 to 8 hours during the subsequent gas production phase to assess long-term polymer recovery, which was found to be minimal (3 percent). Sampling of injected fluid and chloride concentrations indicated that as the flowback and gas production periods progressed, decreasing proportions of the extracted water consisted of the injected fluid, while increasing proportions were natural formation water. In other words, natural formation water was able to bypass viscous gel trapped in the formation and flow into the production wells.

The authors further cited laboratory studies indicating that water may flow past the gel in sand such as that used as proppant in these studies (Willberg et al., 1997). Because the gel is more viscous than water, it is easier for water to respond to pumping and flow through the formation towards the production well. As Willberg et al. (1997) writes, "Production of formation water effectively competes and eventually supersedes residual fracturing fluid recovery, thereby limiting the overall cleanup efficiency." Given that the environments in which coalbed methane is produced are also generally saturated with water, and similar sands are used as proppants, it is possible that gel recovery is impeded in much the same way in coalbed methane stimulations.

Willberg et al. (1998) conducted another flowback analysis and described the effect of flowback rate on cleanup efficiency in an initially dry, very low permeability (0.001 md) shale. Some wells in this study were pumped at low flowback rates (less than 3 barrels per minute (bbl/min). Other wells were pumped more aggressively at greater than 3 bbl/min. Thirty-one percent of the injected fluids were recovered when low flowback rates were applied over a 5-day period. Forty-six percent of the fluids were recovered when aggressive flowback rates were applied in other wells over a 2-day period. Additional fluid recovery (10 percent to 13 percent) was achieved during the subsequent gas production phase, resulting in a total recovery rate of 41 percent to 59 percent. Willberg speculated that the lower recovery rate in the 1997 study was due to the pumping of large amounts of formation water during the recovery process, compared to the 1998 study that was conducted in a relatively dry environment.

3.3.2 Mechanisms Affecting Fluid Recovery

A variety of site-specific factors will influence the recovery efficiency of fracturing fluids. These factors are summarized as follows:

- Fluids can "leakoff" (flow away) from the primary hydraulically induced fracture into smaller secondary fractures. The fluids then become trapped in the secondary fractures and/or pores of porous rock.

- Fluids can become entrapped due to the "check-valve effect," wherein fractures narrow again after the injection of fracturing fluid ceases, formation pressure decreases, and extraction of methane and groundwater begins.

- Some fluid constituents can become adsorbed to coal or react chemically with the formation.

- Some volume of the fluids, moving along the hydraulically induced fracture, may move beyond the capture zone of the pumping well, and thus cannot be recovered during fluid recovery. The capture zone of the production well is that portion of the aquifer that contributes water to the well.

- Some fluid constituents may not completely mix with groundwater and therefore would be difficult to recover during production pumping.

Each of these mechanisms is discussed in greater detail in this section.

Fluid Leakoff

Fluids can be "lost" (i.e., remain in the subsurface unrecovered) due to "leakoff" into connected fractures and the pores of porous rocks (Figure 3-7). Fracturing fluids injected into the primary hydraulically induced fracture can intersect and flow (leakoff) into preexisting smaller natural fractures. Some of the fluids lost in this way may occur very close to the well bore after traveling minimal distances in the hydraulically induced fracture before being diverted into other fractures and pores. The volume of fracturing fluids that may be lost in this way depends on the permeability of the rocks and the surface area of the fracture(s).

The high injection pressures of hydraulic fracturing can force the fracturing fluids to be transported deep into secondary fractures. The cleats in coal are presumed to play an important role in leakoff (Olson, 2001). Movement into smaller fractures and cleats can be to a point where flowback efforts will not recover them. The pressure reduction caused by pumping during subsequent production is not sufficient to recapture all the fluid that has leaked off into the formation. The loss of fluids due to leakoff into small fractures and pores is minimized by the use of cross-linked gels, discussed in more detail in Chapter 4.

Check-Valve Effect

A check-valve effect occurs when natural or propagating fractures open and allow fluids to flow through when fracturing pressure is high, but subsequently prevent the fluids from flowing back towards the production well as they close after fracturing pressure decreases (Warpinski et al., 1988; Palmer et al., 1991a). A long fracture can be pinched off at some distance from the well. This reduces the effective fracture length available to transport methane from various locations within the coalbed to the production well. Fluids trapped beyond the "pinch point" are unlikely to be recovered during flowback.

In most cases, when the fracturing pressure is released, the fracture closes in response to natural subsurface compressive stresses. Because the primary purpose of hydraulic fracturing is to increase the effective permeability of the target formation and connect new or widened fractures to the well, a closed fracture is of little use. Therefore, a component of coalbed methane production well development is to "prop" the fracture open, so that the enhanced permeability from the pressure-induced fracturing persists even after fracturing pressure is terminated. To this end, operators use a system of fluids and "proppants" to create and preserve a high-permeability fracture-channel from the well into the formation.

The check-valve effect takes place in locations beyond the zone where proppants have been emplaced (or in smaller secondary fractures that have not received any proppant). Because of the heterogeneous, stratified, and fractured nature of coal deposits, it is likely that some volume of stimulation fluid cannot be recovered due to its movement into zones that were not completely "propped."

Adsorption and Chemical Reactions

Adsorption and chemical reactions can prevent the fluid from being recovered. Adsorption is the process by which fluid constituents adhere to a solid surface (i.e., the coal, in this case) and are thereby unavailable to flow with groundwater. Adsorption to coal is likely; however, adsorption to other surrounding geologic material (e.g., shale, sandstone) is likely to be minimal. Another possible reaction affecting the recovery of fracturing fluid constituents is the neutralization of acids (in the fracturing fluids) by carbonates in the subsurface.

Movement of Fluids Outside the Capture Zone

Fracturing fluids injected into the target coal zone flow into fractures under very high pressure. The hydraulic gradients driving fluid flow away from the well during injection are much greater than the hydraulic gradients pulling fluid flow back towards the production well during flowback and production pumping. Some portion of the coalbed methane fracturing fluids could be forced along the hydraulically induced fracture to a point beyond the capture zone of the production well. The size of the capture zone will be affected by the regional groundwater gradients, as well as by the drawdown caused by the well. If fracturing fluids have been injected to a point outside of the well's capture zone, they will not be recovered through production pumping and, if mobile, may be available to migrate through an aquifer. Site-specific geologic, hydrogeologic, injection pressure, and production pumping details would provide the information needed to estimate the dimension of the production well capture zone and the extent to which the fracturing fluids might travel, disperse, and dilute.

Incomplete Mixing of Fracturing Fluids with Water

Steidl (1993) documented the occurrence of a gelling agent that did not dissolve completely and formed clumps at 15 times the injected concentration in the fracture induced by one well. Steidl (1993) also directly observed, in his mined-through studies, gel hanging in stringy clumps in many other fractures induced by that one well. As Willberg et al. (1997) noted, laboratory studies indicate that fingered flow of water past residual gel may impede fluid recovery. Therefore, some fracturing fluid gels appear not to flow with groundwater during production pumping and remain in the subsurface unrecovered. Such gels are unlikely to flow with groundwater during production, but may present a source of gel constituents to flowing groundwater during and after production.

3.4 Measuring and Predicting the Extent of Fluid Movement

Because fractures can possibly connect with or even extend into USDWs, fracture height is relevant to the issue of whether hydraulic fracturing fluids can affect USDWs. Current methods of measuring or predicting fracture growth, including mathematical models, are described. The models are effective in setting parameters for a given hydraulic fracture operation. Coalbed methane well operators have a financial incentive to keep the hydraulically induced fracture generally within the target coal zone so that expenditures on hydraulic horsepower, fracturing fluids, and proppants are minimized for commercial extraction of methane from the coal. In addition, a detailed review is included on “mined-through” studies that were conducted primarily by the U.S. Bureau of Mines. These studies provide unique information on the direct measurement of the dimensions and other characteristics of fractures created in coal seams and surrounding strata by hydraulic fracturing. Paint, injected with the fracturing fluids, was used as a tracer in some of these studies, enabling one of the most direct measurements of the extent of fluid movement due to hydraulic fracturing.

The particular stratigraphy of a fracturing site will determine what fracture heights are significant with respect to USDWs. That is, a given fracture height may be considered small at a particular site in one basin, but may be more significant in another basin where there is a smaller vertical separation between hydraulically fractured coalbeds and a USDW. The extent of fracturing is controlled by the characteristics of the geologic formations (including the presence of shales or natural fractures), the volume and type of fracturing fluid used, the pumping pressure, and the depth at which the fracturing is performed. Several methods are available to operators to measure or predict the extent to which fracture stimulation fluid moves and the related values of maximum induced fracture extension and “propped” fracture height. Propped height (i.e., height in the fracture to which proppant has been distributed) was found to be 60 percent to 75 percent of total vertical fracture height (Mavor et al., 1991; Rahim and Holditch, 1992; Nolte and Smith, 1981; Nolte and Economides, 1991; Zuber et al., 1991). Furthermore, in cases where proppant “screens out” or emplacement partially fails, proppant may exist in 20 percent or less of fracture height.

Both the current and some older methods for estimating fracture dimensions are discussed below. In general, these methods fall into three areas: direct measurements; indirect measurements; and model estimates. Terminology in the literature regarding fracture dimensions is sometimes inconsistent; some articles describe “measured” fracture dimensions when referring to indirect measures or even model estimates.

3.4.1 Direct Measurements

Direct measures include mined-through (or mineback) studies (where mining of subsurface coal seams that were previously hydraulically fractured allows direct access to fractures for measurement); dye tracing conducted in conjunction with mined-through studies; downhole cameras (used to visually inspect fractures in the borehole), including borehole image logging and downhole video logging; surface and downhole tiltmeters; and microseismic monitoring (or imaging). Fracture geometry is most dependably measured by microseismic monitoring or downhole tiltmeters (Warpinski, 2001), or by tracers (Diamond and Oyler, 1987). Downhole cameras can be used only in open bore holes (uncased wells), so fracture measurements using cameras do not reflect conventional coalbed methane fracturing that typically occurs in cased wells. Both downhole cameras and mined-through approaches to fracture measurements are limited to areas exposed by the wellbore and mining activities, respectively. Nonetheless, the mined-through studies provide the most direct approach for estimating fracture dimensions.

Mined-Through Studies

Twenty-two coalbeds were hydraulically fractured, subsequently mined-through, and investigated several months to several years later in Pennsylvania, Alabama, West Virginia, Illinois, Virginia, and Utah (Diamond 1987a and b; Diamond and Oyler 1987). Similar studies have been conducted by Jeffrey et al. (1993) in Queensland, Australia, and Steidl (1991a; 1991b; 1993) in the Black Warrior Basin, Alabama. The Diamond studies were designed to evaluate the effect of the hydraulic fracturing treatment on mining safety. All the mined-through studies enabled direct observation of induced fractures and surrounding material and evaluation of the movement of sand proppant and fracturing fluids through both induced and natural fractures. Eight of the treatments included fluorescent paint in the injected fluid to aid in mapping fluid movement (Diamond 1987a and b).

Steidl (1993) found that fracture widths were typically 0.1 inch, but could be as wide as 4 inches. Measured sand-filled (propped) fractures were 2 to 526 feet in length (Steidl 1993, Jeffrey et al., 1993), although Steidl found a sand-free extension of a sand-filled fracture 870 feet from the borehole. Diamond (1987a and b) found treatment fluids beyond the sand-filled portions of the fractures using paint injected with the fracturing fluids. In most of the wells where paint was injected, the paint was found 200 to 300 feet beyond the sand-filled portions of fractures. However in one borehole, paint extended out from the well bore for 630 feet, although the sand-filled portion of the fracture was only 95 feet in extent (Diamond, 1987a and b). These paint-coated fractures were produced using typical hydraulic fracturing processes in fairly typical coalbed methane geologic conditions.

Fluorescent paint was observed in locations that indicated fluids did not travel in a direct linear path from the induced fracture. Fluids often followed a stair-step pathway through the coalbed (Diamond and Oyler, 1987). The fluorescent paint was also useful for identifying small fractures penetrated by treatment fluids but not by sand proppant. Multiple small, parallel fractures were penetrated by treatment fluids at many of the locations studied. Given that treatment fluids have been documented to travel more than six times farther than sand proppant, studies looking at the dimensions of sand-filled fractures alone are unlikely to capture the extent of fluid movement within and beyond coalbed methane reservoirs (Diamond, 1987a and b).

About half of the sites studied by Diamond (1987a and b) and Diamond and Oyler (1987) had fractures penetrating beyond the coalbeds into the roof rock (the rock overlying the coal in the mined areas). Jeffrey et al. (1993) found that most of the proppant in three of their four treatments was found in the roof rock. Thus, mined-through studies in Australia and in six states in the United States found that hydraulic fracturing fluids penetrated into, and, when shales were very thin, through strata surrounding coalbeds in 50 percent of stimulations in the United States and 75 percent of the stimulations in Australia. The mined-through studies, however, generally cannot provide measures of how far the fractures actually extend, since mining did not extend beyond the coal and into the roof rock.

Other Direct Measurements

A discussion of other fracture diagnostic methods is provided in DOE's paper "Hydraulic Fracturing" (provided as Appendix A).

> "Fracture diagnostics involves analyzing the data before, during and after a hydraulic fracture treatment to determine the shape and dimensions of both the created and propped fracture. Fracture diagnostic techniques have been divided into several groups (Cipolla and Wright, 2000).
>
> **Direct far field techniques**
>
> Direct far field methods are comprised of tiltmeter fracture mapping and microseismic fracture mapping techniques. These techniques require delicate instrumentation that has to be emplaced in boreholes surrounding and near the well to be fracture treated. When a hydraulic fracture is created, the expansion of the fracture will cause the earth around the fracture to deform. Tiltmeters can be used to measure the deformation and to compute the approximate direction and size of the created fracture. Surface tiltmeters are placed in shallow holes surrounding the well to be fracture treated and are best for determining fracture orientation and approximate size. Downhole tiltmeters are placed in vertical wells at depths near the location of the zone to be fracture treated. As with surface tiltmeters, downhole tiltmeter data can be analyzed to determine the orientation and dimensions of the created fracture, but are most useful for determining fracture height. Tiltmeters have been used on an

> experimental basis to map hydraulic fractures in coal seams (Nielson and Hanson, 1987).
>
> Microseismic fracture mapping relies on using a downhole receiver array of accelerometers or geophones to locate microseisms or micro-earthquakes that are triggered by shear slippage in natural fractures surrounding the hydraulic fracture. … In essence, noise is created in a zone surrounding the hydraulic fracture. Using sensitive arrays of instruments, the noise can be monitored, recorded, analyzed and mapped.
>
> …Microseismic monitoring has traditionally been too expensive to be used on anything but research wells, but its cost has dropped dramatically in the past few years, so although still expensive (on the order of $50,000 to $100,000), it is being used more commonly throughout the industry. … If the technology is used at the beginning of the development of a field, however, the data and knowledge gained are often used on subsequent wells, effectively spreading out the costs.
>
> **Direct near-wellbore techniques**
>
> Direct near-wellbore techniques are run in the well that is being fracture treated to locate or image the portion of fracture that is very near (inches) the wellbore. Direct near-wellbore techniques…[include] borehole image logging [and] downhole video logging, and caliper logging. If a hydraulic fracture intersects the wellbore, these direct near-wellbore techniques can be of some benefit in locating the hydraulic fracture.
>
> However, these near-wellbore techniques are not unique and cannot supply information on the size or shape of the fracture once the fracture is 2-3 wellbore diameters in distance from the wellbore. In coal seams, where multiple fractures are likely to exist, the reliability of these direct near-wellbore techniques are even more speculative. As such, very few of these direct near-wellbore techniques are used on a routine basis to look for a hydraulic fracture."

3.4.2 Indirect Measurements

Indirect measures of fracture dimensions include pressure analyses (sometimes referred to as net, treating, or bottom hole pressure analyses that are sometimes analyzed in conjunction with proppant volume assessments) and radioactive tracing. (Radioactive tracing can be conducted on either fracturing fluids or proppants. It is sometimes referred to as a "tagged" study, and is typically measured through gamma ray logging.) Pressure analyses generally monitor bottom hole pressures (BHPs) over time to infer fracture propagation. For example, declining net pressure during water/gel pumping stages indicates rapid fracture height growth (Saulsberry, et al., 1990). Proppant volumes and historical fracturing and methane production data are used to improve estimates based on pressure analyses. Fracture heights and lengths that are inferred by pressure analyses are commonly described in the literature as "measured." Radioactive tracers provide only approximate estimates of fracture dimensions because they are measured in near-wellbore environments.

3.4.3 Model Estimates

The other main category of indirect measures of fracture dimensions is hydraulic fracture modeling. The basic elements of fracture modeling were developed between 1955 and 1961 (Nolte and Economides, 1991). Many modeling studies were conducted to aid in the design of fracture stimulation treatments (i.e., to determine the volume and pump rate of fluids and proppants that are required to achieve a desired fracture geometry).

Model estimates of fracture heights and lengths are common, including estimates using three-dimensional (and quasi-three dimensional) models. Modeling capabilities have advanced considerably in the last several 15 years, and the newest P3D (pseudo 3 dimensional) models simultaneously predict height, width, and length based on treatment input data and reservoir parameters (Olson, 2001). A discussion of indirect fracture modeling techniques is provided by DOE in the "Hydraulic Fracturing" paper (provided as Appendix A). An excerpt from that paper is provided below.

> "The indirect fracture techniques consist of hydraulic fracture modeling of net pressures, pressure transient test analyses, and production data analyses. Because the fracture treatment data and the post-fracture production data are normally available on every well, the indirect fracture diagnostic techniques are the most widely used methods to estimate the shape and dimensions of both the created and the propped hydraulic fracture.
>
> The fracture treatment data can be analyzed with a P3D fracture propagation model to determine the shape and dimensions of the created fracture. The P3D model is used to history match the fracturing data, such as injection rates and injection pressures. Input data, such as the in-situ stress and permeability in key layers of rock can be varied (within reason) to achieve a history match of the field data.
>
> Post-fracture production and pressure data can be analyzed using a 3D reservoir simulator to estimate the shape and dimensions of the propped fracture. Values of formation permeability, fracture length and fracture conductivity can be varied in the reservoir model to achieve a history match of the field data.
>
> The main limitation of these indirect techniques is that the solutions are not unique and require as much fixed data as possible. For example, if the engineer has determined the formation permeability from a well test or production test prior to the fracture treatment, so that the value of formation permeability is

> known and can be fixed in the models, the solution concerning values of fracture length become more unique. Most of the information in the literature concerning post-fracture analyses of hydraulic fractures has been derived from these indirect fracture diagnostic techniques."

There are several caveats regarding the use and interpretation of model estimates. In-situ stress values of the target coal seams and surrounding strata are important model inputs. Actual in-situ stress measurements are very difficult to obtain and are rarely conducted (Warpinski, 2001). Therefore, almost all modeling is conducted using inferred stress values (as estimated, for example, from the mechanical and lithological properties of rocks from, or similar to those in, the target coal zone). Given the geologic variability and site-specific influences on fracture behavior described above, the reliability of fracture height and length estimates obtained from various models is obviously influenced by the quality of the inferred model inputs regarding geologic factors.

Models also necessarily rely on simplifying assumptions to simulate fracture propagation and behavior through sometimes complex geologic zones. As with all modeling, the reliance on inferred input variables and some assumptions introduces some subjectivity to the modeling process. Dependable modeling requires knowledge of and allowance for the detailed stratigraphy of the geologic strata throughout the coal zone. (It was noted in section 3.2.2 that thin clay layers or ash beds can influence fracture behavior.) Simplified geologic models might represent the subsurface as 2 to 3 distinct geologic layers, to reduce computing and data requirements, when a 30- or 50-layer model may be necessary to accurately predict fracture height (Rahim et al., 1998). Nevertheless, models are necessary simplifications of fracture behavior in the geologic subsurface, and significant research has been conducted in the last several decades so that model estimates of fracture behavior in methane-producing coalbeds are now an invaluable tool for industry.

3.4.4 Limitations of Fracture Diagnostic Techniques

Warpinski (1996) discussed many of these same fracture diagnostic techniques. In general, the best fracture diagnostics techniques are expensive and used only in research wells. Fracture diagnostic techniques can provide important data when entering a new production area or a new formation. However, for coalbed methane wells, where costs must be minimized to maintain profitability, the best fracture diagnostic techniques are rarely used and are often considered to be prohibitively expensive.

Warpinksi (2001) further provided other general conclusions regarding estimates of fracture dimensions:

- Fracture heights inferred from pressure data are almost always greater than the corresponding heights measured with the more dependable microseismic monitoring or tiltmeters.

- Actual fracture lengths may be greater or less than the lengths estimated from models or inferred from pressure analyses, depending on many site-specific geologic factors.

- Fracture geometry can be accurately measured using microseismic monitoring and measured somewhat using downhole tiltmeters. These technologies have been found to be invaluable for determining how fractures actually behave.

Table 3-1 lists certain diagnostic techniques and their limitations.

Table 3-1. Limitations of Fracture Diagnostic Techniques (Appendix A: DOE, Hydraulic Fracturing)

Parameter	Technique	Limitation
Fracture Height	Tracer logs	Shallow depth of investigation; shows height only near the wellbore
Fracture Height	Temperature logs	Difficult to interpret; shallow depth of investigation; shows height only near wellbore
Fracture Height	Stress profiling	Does not measure fracture directly; must be calibrated with *in-situ* stress tests
Fracture Height	P3D models	Does not measure fracture directly; estimates vary depending on which model is used
Fracture Height	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Height	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Length	P3D models	Length inferred, not measured; estimates vary greatly depending on which model is used
Fracture Length	Well testing	Large uncertainties depending upon assumptions and lack of prefracture well test data
Fracture Length	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Length	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Azimuth	Core techniques	Expensive to cut core and run tests; multiple tests must be run to assure accuracy
Fracture Azimuth	Log techniques	Requires open hole logs to be run; does not work if natural fractures are not present
Fracture Azimuth	Microseismic	Analysis intensive; expensive for determination of azimuth
Fracture Azimuth	Tiltmeters	Useful only to a depth of 5,000 feet; requires access to large area; expensive
From: Appendix A, DOE, Hydraulic Fracturing		

3.5 Summary

Coalbed methane development began as a safety measure to extract methane, an explosion hazard, from coal prior to mining. Since 1980, coalbed methane production has grown rapidly, spurred by tax incentives to develop non-conventional energy production. At the end of 2000, coalbed methane production from 13 states totaled 1.353 trillion cubic feet, an increase of 156 percent from 1992. At year-end 2000, coalbed methane production accounted for about 7 percent of the total United States dry gas production and 9 percent of proven dry gas reserves (EIA, 2001).

Methane within coalbeds is not “trapped” under pressure as in conventional gas scenarios. Only about 5 to 9 percent of the methane is present as “free” gas within the natural fractures, joints, and cleats. Almost all coalbed methane is adsorbed within the micro-porous matrix of the coal (Koenig, 1989; Winston, 1990; Close, 1993).

Coalbed methane production starts with high-pressure injection of fracturing fluids and proppant into targeted coal zones. The resulting induced or enlarged fractures improve the connections of the production well to the fracture networks in and around the coal zone. When production begins, water is pumped from the fractures in the coal zone to reduce pressure in the formation. When pressures are adequately reduced, methane desorbs from the coal matrix, moves through the network of induced and natural fractures in the coal toward the production well, and is extracted through the well and to the surface.

Fractures that are created at shallow depths (less than approximately 1,000 feet) typically have more of a horizontal than a vertical component. Vertical fractures created at deeper depths can propagate vertically to shallower depths where they may develop a horizontal component. These “T-fractures” may involve the fracture “turning” and developing horizontally at a coalbed-mudstone interface.

Fracture behavior through coal, shale, and other geologic strata commonly present in coal zones depends on site-specific factors such as relative thicknesses and in-situ stress differences between the target coal seam(s) and the surrounding geologic strata, as well as the presence of pre-existing natural fractures. Often, a high stress contrast between adjacent geologic strata results in a barrier to fracture propagation. This occurs in coal zones where there is a geologic contact between a high-stress coal seam and an overlying, thick, relatively low-stress shale.

The fluids used for fracture development are injected at high pressure into the targeted coal zone in the subsurface. These fluids may be “clear” (primarily consisting of water, but may include acid, oil, or water with friction-reducer additives) or “gelled” (viscosity-modified water using guar or other gelling agents). Hydraulic fracturing in coalbed methane wells may require 50,000 to 350,000 gallons of fracturing fluids and 75,000 to 320,000 pounds of sand as proppant to prop or maintain the opening of fractures after the injection (fracturing) pressure is reduced (Holditch et al., 1988 and 1989; Jeu et al., 1988;

Hinkel et al., 1991; Holditch, 1993; Palmer et al., 1991b, 1993a, and 1993b). More typical injection volumes, based on average injection volume data provided by Halliburton for six coalbed methane locations, indicate a maximum average injection volume of 150,000 gal/well and a median average injection volume of 57,500 gal/well (Halliburton, Inc., 2003).

In any fracturing job, some fracturing fluids cannot be recovered and are said to be “lost” to the formation. Palmer (1991a) observed that for fracture stimulations in multi-layered coal formations, 61 percent of stimulation fluids were recovered during a 19-day production sampling of a coalbed methane well in the Black Warrior Basin. He further estimated that from 68 percent to possibly as much as 82 percent would eventually be recovered. A variety of site-specific factors, including leakoff into the coal seams and surrounding strata, the check-valve effect, adsorption and other geochemical processes, and flow through the hydraulic fracture beyond the well’s capture zone will serve to reduce recovery of hydraulic fracturing fluids injected into subsurface coal zones to promote coalbed methane extraction.

The mined-through studies by the U.S. Bureau of Mines (see Diamond, 1987a and b) and others provide important directly-measured characteristics of hydraulic fracturing in coal seams and surrounding strata. Further, paint tracer studies conducted as part of Diamond’s (1987a and b) mined-through studies can provide estimates on the extent of hydraulic fracturing fluid movement, which may be greater than the extent of sand-filled (propped) hydraulic fracture heights or lengths given fluid movement through natural fractures. These estimates of the extent of fluid movement are usually limited by the area exposed to mining.

A significant amount of diagnostic research has been conducted in the last decade enabling industry to develop a practical, applied understanding of general fracture behavior as it relates to methane production. Operators use a number of techniques to estimate fracture dimensions to design fracture stimulation treatments to minimize expenditures on hydraulic horsepower, fracturing fluids, and proppants. Modeling is increasingly more sophisticated, but still commonly depends on at least some inferred (and subjective) input data. Reliable fracture height and length can be measured accurately by microseismic monitoring and tiltmeters (Warpinksi, 2001).

Figure 3-1. Major United States Coal Basins

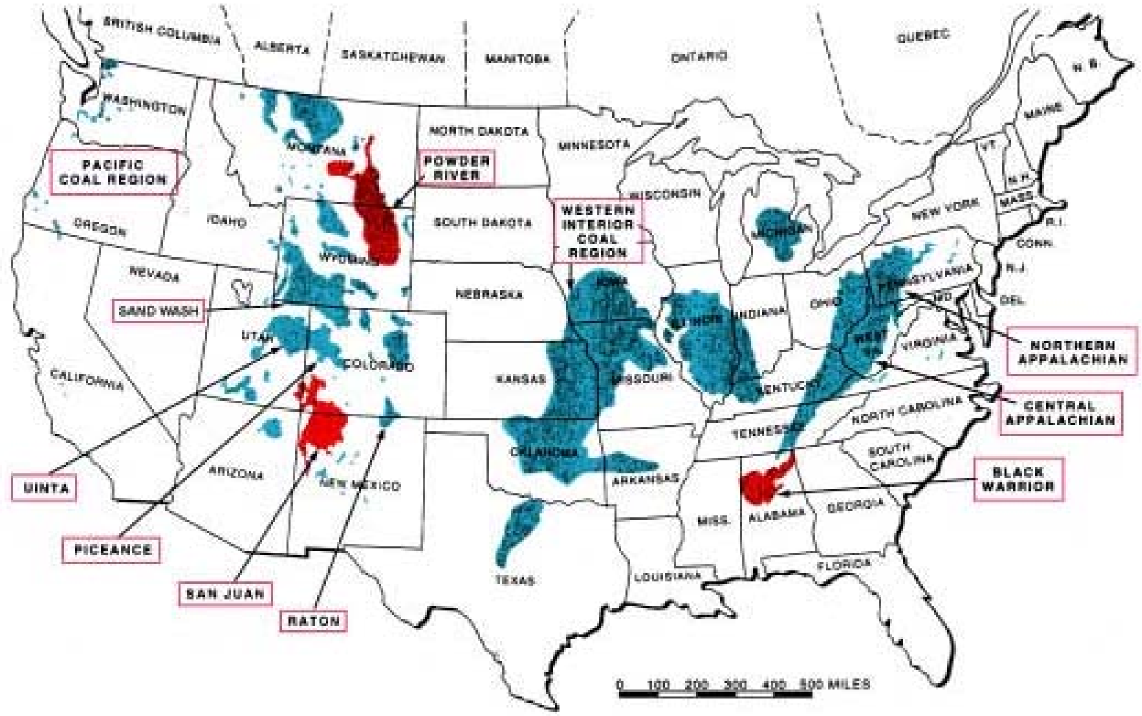
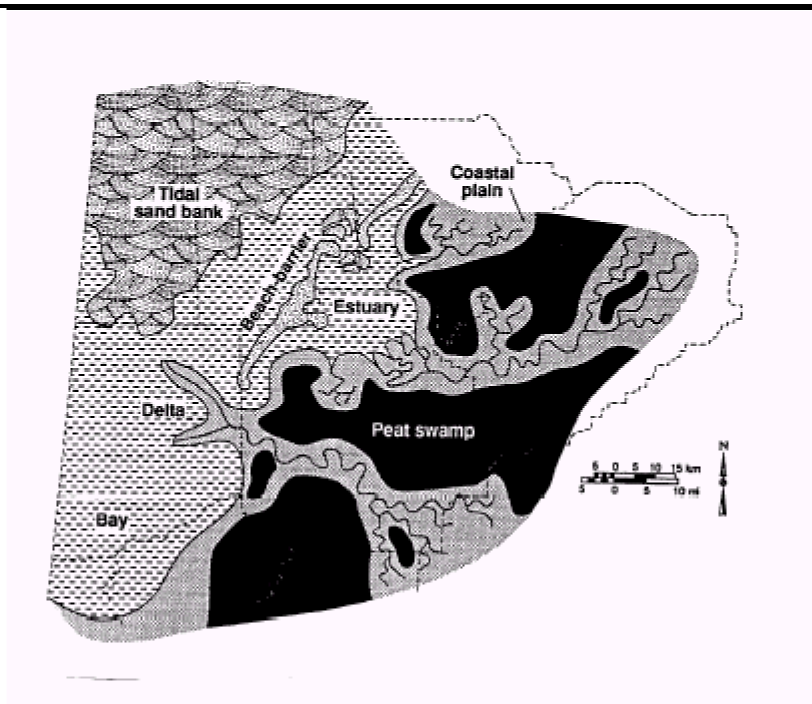


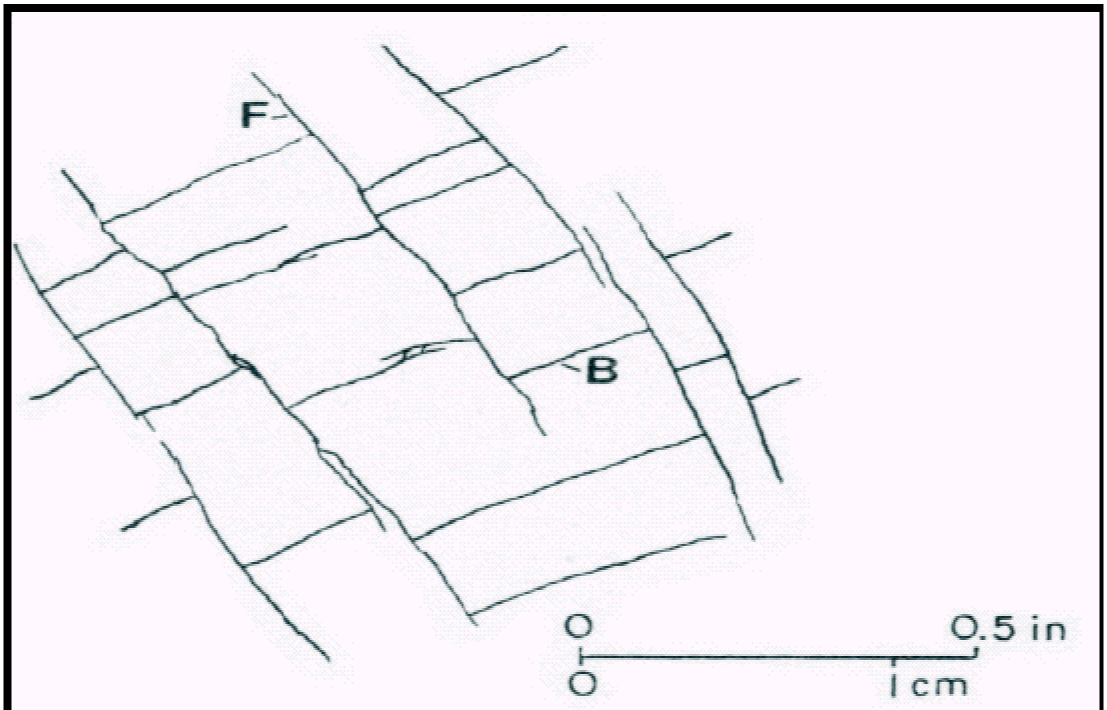
Figure 3-2. Geography of an Ancient Peat-Forming System



Geography of an Ancient Peat-Forming System (example from Black Warrior Basin, Alabama)
(Pashin and Hinkle, 1997)

Figure 3-2

Figure 3-3. Schematic Representation of "Face Cleat" (F) and "Butt Cleat" (B)



Schematic Representation of "Face Cleat" (F) and "Butt Cleat" (B) (Ayers et al., 1994)

Figure 3-3

Figure 3-4. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells

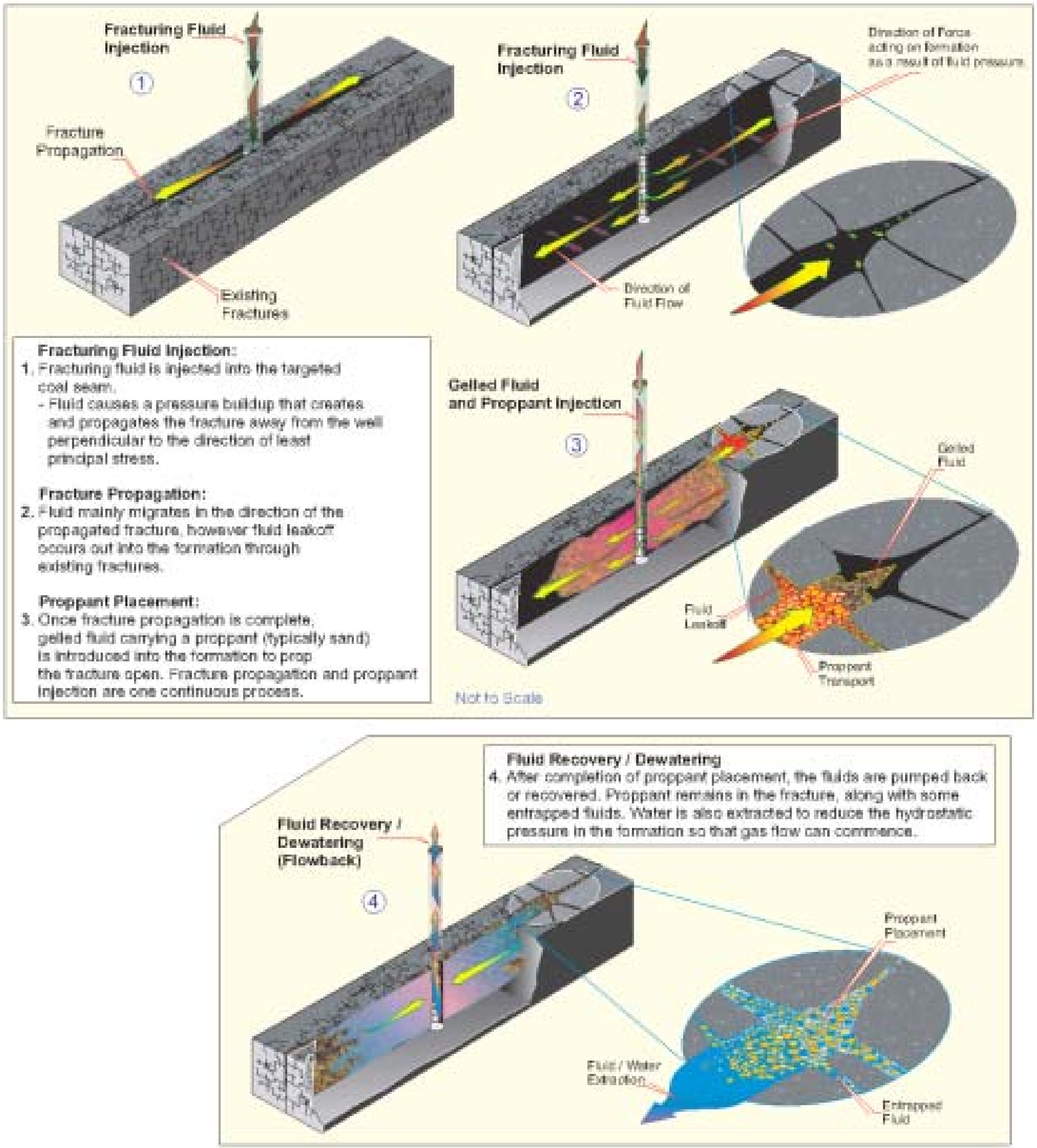


Figure 3-4. A Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells (Continued)

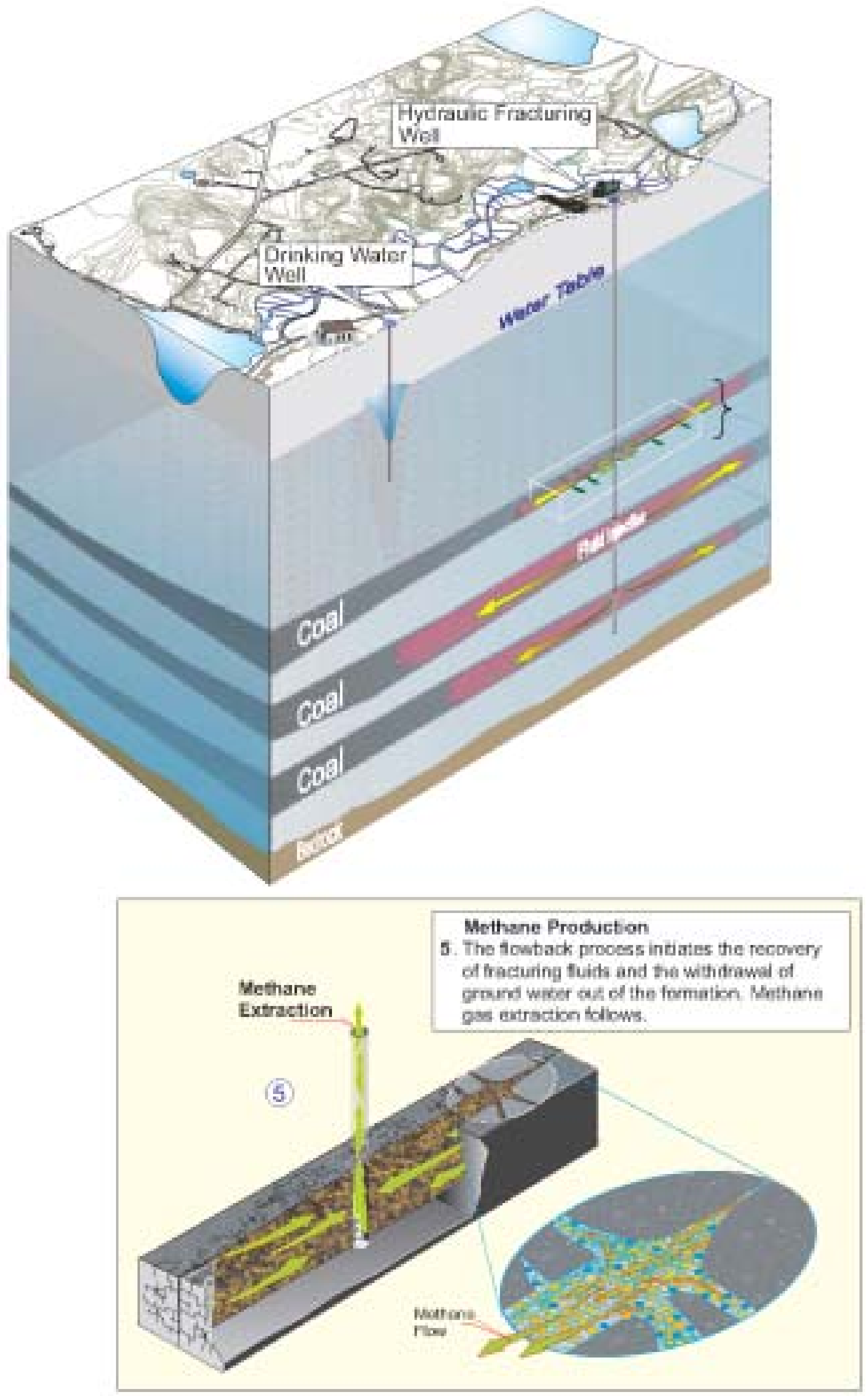
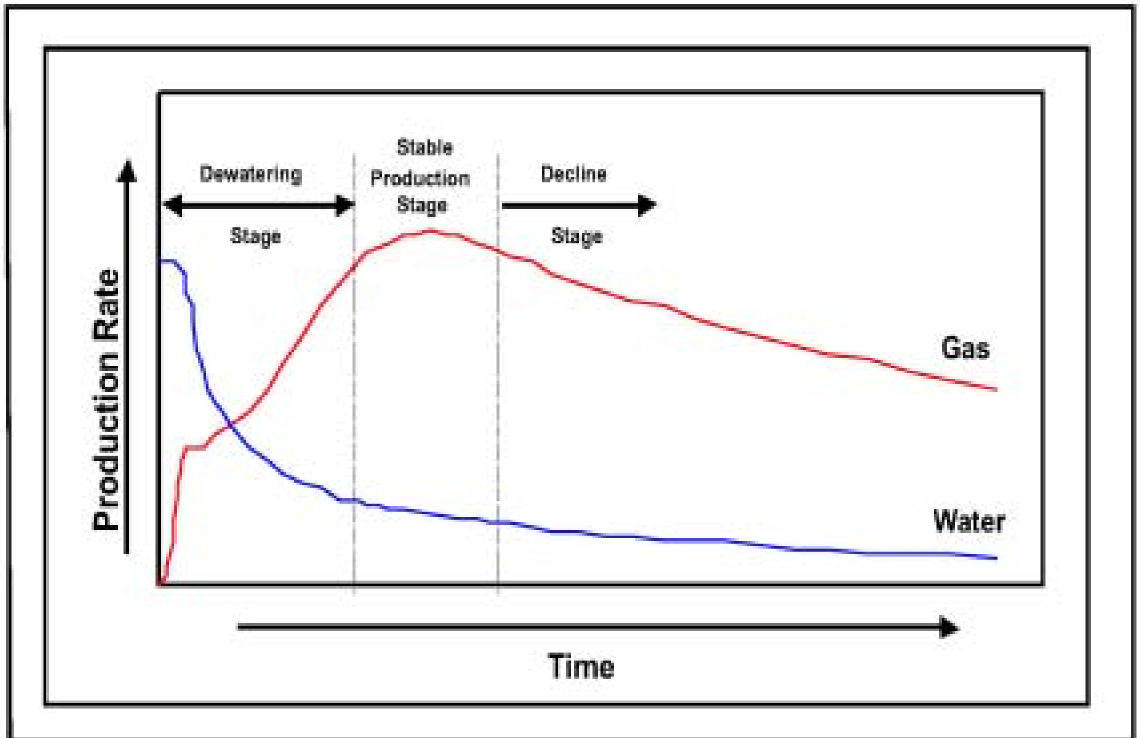


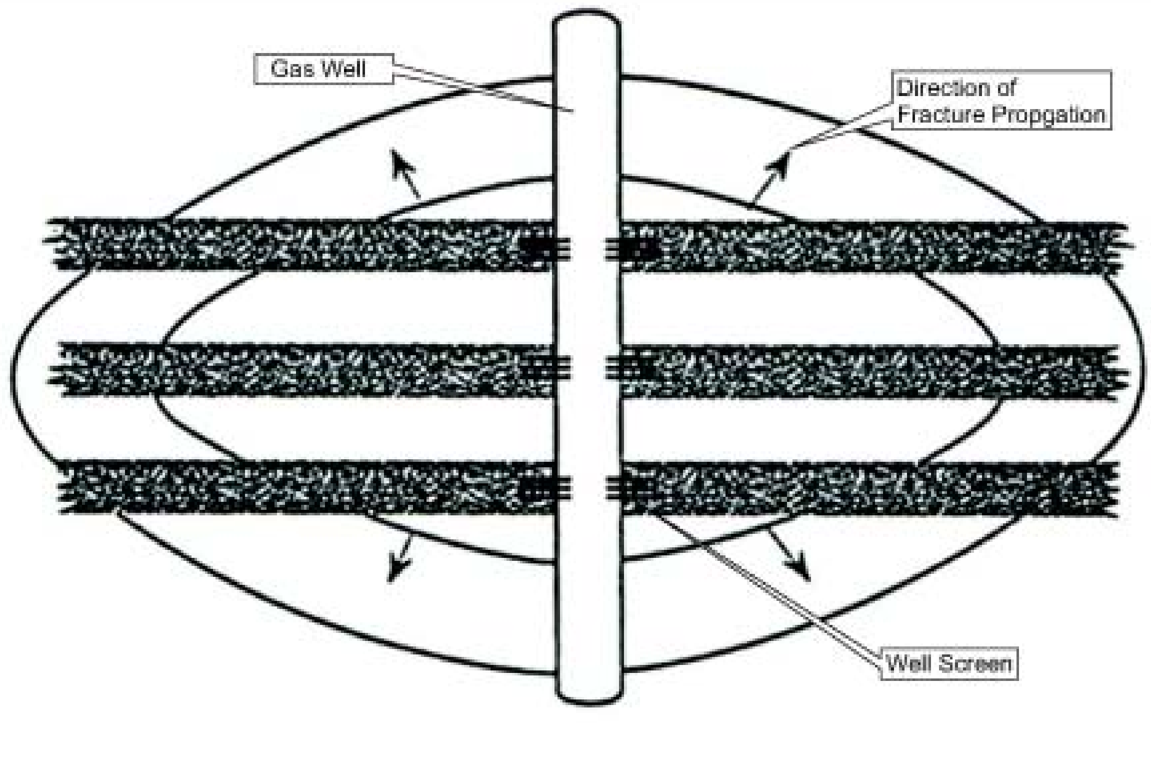
Figure 3-5. Water And Gas Production Over Time



Water and Gas Production Over Time (Saulsberry et al., 1996)

Figure 3-5

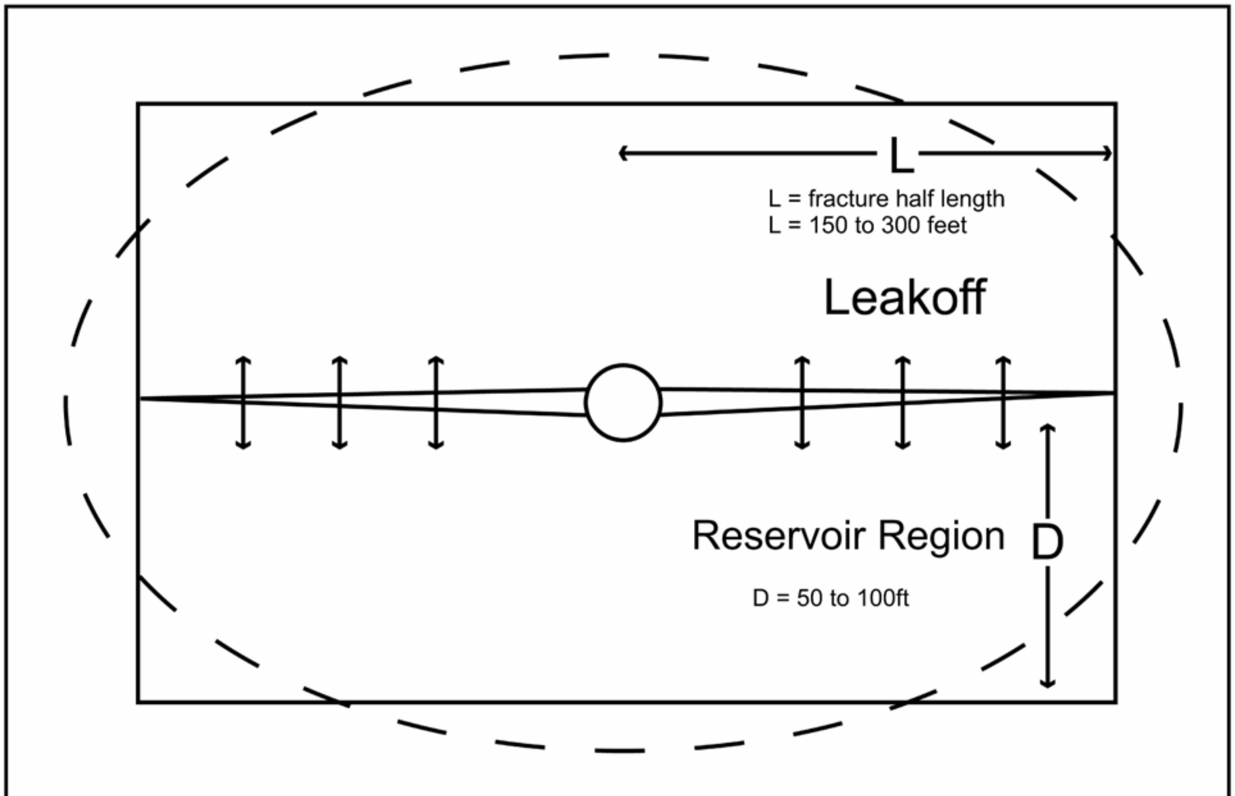
Figure 3-6. Side-View of a Vertical Hydraulic Fracture Typical of Coalbeds



Side-View of a Vertical Hydraulic Fracture Typical of Coalbeds
Most hydraulic fractures penetrate several coal seams.
(Palmer et al., 1991)

Figure 3-6

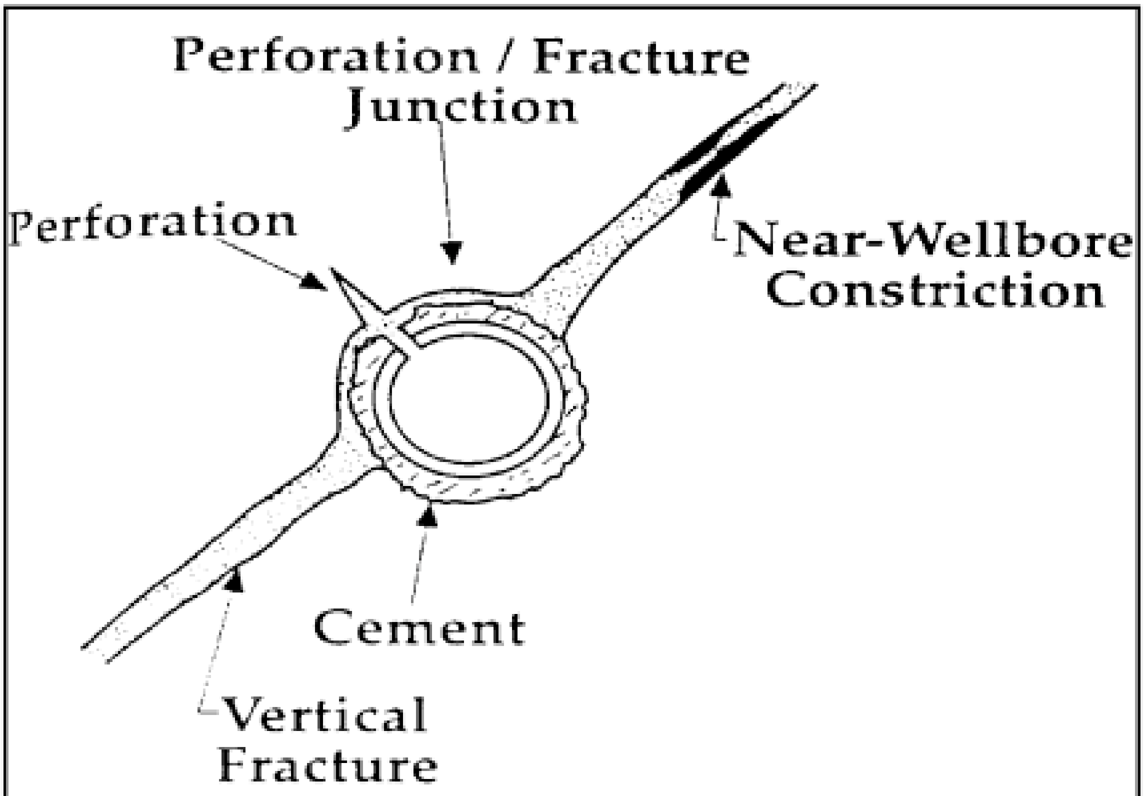
Figure 3-7. Plan View (Looking Down the Wellbore) of Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff



Plan View of a Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff (Palmer et al., 1991).

7/14/01 kk 1027-3-7.cdr | Figure 3-7

Figure 3-8. Plan View of a Vertical Hydraulic Fracture



Plan View (Looking Down the Wellbore) of a Vertical Hydraulic Fracture (Palmer et al., 1991)

Figure 3-8

Chapter 4
Hydraulic Fracturing Fluids

This chapter summarizes the information EPA collected on the types and volumes of fracturing fluids and additives that may be used for hydraulic fracturing of coalbed methane wells. This chapter also provides EPA's evaluation of the fate and transport of fracturing fluids that are injected into targeted coal layers during the hydraulic fracturing process. This evaluation was conducted to provide the Agency with information on whether a Phase II study is warranted. Captioned photographs in this chapter show the use of fracturing fluids at a coalbed methane well (Figures 4-1 through 4-11 at the end of this chapter).

4.1 Introduction

The types and use of fracturing fluids have evolved greatly over the past 60 years and continue to evolve. The U.S. oil and gas industry has used fluids for fracturing geologic formations since the early 1940s (Ely, 1985). *The Handbook of Stimulation Engineering* (Ely, 1985), a comprehensive history of the evolution of hydraulic fracturing fluids in the oil and gas industry, was used as a source of information for this chapter. In addition, EPA identified fluids and fluid additives commonly used in hydraulic fracturing through literature searches, reviews of relevant MSDSs provided by service companies, and discussions with field engineers, service company chemists, and state and federal employees.

Available scientific literature indicates that hydraulic fracturing fluid performance became a prevalent research topic in the late 1980s and the 1990s. Most of the literature pertaining to fracturing fluids relates to the fluids' operational efficiency rather than their potential environmental or human health impacts. There is very little documented research on the environmental impacts that result from the injection and migration of these fluids into subsurface formations, soils, and USDWs. Some of the existing literature does offer information regarding the basic chemical components present in most of these fluids. The composition of fracturing fluids and additives is discussed in detail in the next section.

The main goal of coalbed hydraulic fracturing is to create a highly conductive fracture system that will allow flow through the methane-bearing coal zone to the production well used to extract methane (and groundwater). Hydraulic fracturing fluids are used to initiate and/or expand fractures, as well as to transport proppant into fractures in coalbed formations. Proppants are sand or other granular substances injected into the formation to hold or "prop" open coal formation fractures created by hydraulic fracturing. The viscosity of fracturing fluids is considered when they are formulated, to provide for efficient transport and placement of proppant into a fracture. Most of the fracturing fluids injected into the formation are pumped back out of the well along with groundwater and methane gas (see section 3.3 in Chapter 3 for a more detailed discussion of fracturing fluid recovery).

4.2 Types of Fracturing Fluids and Additives

Service companies have developed a number of different oil- and water-based fluids and treatments to more efficiently induce and maintain permeable and productive fractures. The composition of these fluids varies significantly, from simple water and sand to complex polymeric substances with a multitude of additives. Each type of fracturing fluid has unique characteristics, and each possesses its own positive and negative performance traits. For ideal performance, fracturing fluids should possess the following four qualities (adapted from Powell et al., 1999):

- Be viscous enough to create a fracture of adequate width.
- Maximize fluid travel distance to extend fracture length.
- Be able to transport large amounts of proppant into the fracture.
- Require minimal gelling agent to allow for easier degradation or "breaking" and reduced cost.

Water-based fracturing fluids have become the predominant type of coalbed methane fracturing fluid (Appendix A: DOE, Hydraulic Fracturing). However, fracturing fluids can also be based on oil, methanol, or a combination of water and methanol. Methanol is used in lieu of, or in conjunction with, water to minimize fracturing fluid leakoff and enhance fluid recovery (Thompson et al., 1991). Polymer-based fracturing fluids made with methanol usually improve fracturing results, but require 50 to 100 times the amount of breaker (e.g., acids used to degrade the fracturing fluid viscosity, which helps to enhance post-fracturing fluid recovery) (Ely, 1985). In some cases, nitrogen or carbon dioxide gas is combined with the fracturing fluids to form foam as the base fluid. Foams require substantially lower volumes to transport an equivalent amount of proppant. Diesel fuel is another component of some fracturing fluids although it is not used as an additive in all hydraulic fracturing operations. A variety of other fluid additives (in addition to the proppants) may be included in the fracturing fluid mixture to perform essential tasks such as formation clean up, foam stabilization, leakoff inhibition, or surface tension reduction. These additives include biocides, fluid-loss agents, enzyme breakers, acid breakers, oxidizing breakers, friction reducers, and surfactants such as emulsifiers and non-emulsifiers. Several products may exist in each of these categories. On any one fracturing job, different fluids may be used in combination or alone at different stages in the fracturing process. Experienced service company engineers will devise the most effective fracturing scheme, based on formation characteristics, using the fracturing fluid combination they deem most effective.

The main fluid categories are:

- Gelled fluids, including linear or cross-linked gels.
- Foamed gels.
- Plain water and potassium chloride (KCl) water.
- Acids.
- Combination treatments (any combination of 2 or more of the aforementioned fluids).

Some of the fluids and fluid additives may contain constituents of potential concern. Table 4-1, at the end of section 4.2.6, lists examples of chemicals found in hydraulic fracturing fluids according to the MSDSs provided by service companies, and potential human health effects associated with the product. It is important to note that information presented in MSDSs is for pure product. Each of the products listed in Table 4-1 is significantly diluted prior to injection.

EPA also obtained two environmental impact statements that were prepared by the Bureau of Land Management (BLM). In these impact statements, BLM identified additional chemical compounds that may be in fracturing fluids including methyl tert butyl ether (MTBE) (U.S. Department of the Interior, CO State BLM, 1998). However, EPA was unable to find any indications in the literature, on MSDSs, or in interviews with service companies that MTBE is used in fracturing fluids to stimulate coalbed methane wells.

4.2.1 Gelled Fluids

Water alone is not always adequate for fracturing certain formations because its low viscosity limits its ability to transport proppant. In response to this problem, the industry developed linear and cross-linked fluids, which are higher viscosity fracturing fluids. Water gellants or thickeners are used to create these gelled fluids. Gellant selection is based on formation characteristics such as pressure, temperature, permeability, porosity, and zone thickness. These gelled fluids are described in more detail below.

Linear Gels

A substantial number of fracturing treatments are completed using thickened, water-based linear gels. The gelling agents used in these fracturing fluids are typically guar gum, guar derivatives such as hydroxypropylguar (HPG) and carboxymethylhydroxypropylguar (CMHPG), or cellulose derivatives such as carboxymethylguar or hydroxyethylcellulose (HEC). In general, these products are biodegradable. Guar is a polymeric substance derived from the seed of the guar plant

(Ely, 1985). Guar gum, on its own, is non-toxic and, in fact, is a food-grade product commonly used to increase the viscosity and elasticity of foods such as ice cream.

To formulate a viscous fracturing gel, guar powder or concentrate is dissolved in a carrier fluid such as water or diesel fuel. Increased viscosity improves the ability of the fracturing fluid to transport proppant and decreases the need for more turbulent flow. Concentrations of guar gelling agents within fracturing fluids have decreased over the past several years. It was determined that reduced concentrations provide better and more complete fractures (Powell et al., 1999).

Diesel fuel has been frequently used in lieu of water to dissolve the guar powder because its carrying capacity per unit volume is much higher (Halliburton, Inc., 2002). “Diesel is a common solvent additive, especially in liquid gel concentrates, used by many service companies for continuous delivery of gelling agents in fracturing treatments” (GRI, 1996). Diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system (Halliburton, Inc., 2002). Using diesel instead of water minimizes the number of transport vehicles needed to carry the liquid gel to the site (Halliburton, Inc., 2002).

The percentage of diesel fuel in the slurried thickener can range between 30 percent and almost 100 percent, based on the MSDSs summarized in Table 4-1. Diesel fuel is a petroleum distillate and may contain known carcinogens. One such component of diesel fuel is benzene, which, according to literature sources, can make up anywhere between 0.003 percent and 0.1 percent by weight of diesel fuel (Clark and Brown, 1977; R. Morrison & Associates, Inc., 2001). Slurried diesel and gel are diluted with water prior to injection into the subsurface. The dilution is approximately 4 to 10 gallons of concentrated liquid gel (guar slurried in diesel) per 1,000 gallons of make-up water to produce an adequate polymer slurry (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001; Consolidated Industrial Services, Inc., Virginia Site Visit, 2001; BJ Services, 2001).

C*ross-linked Gels*

One major advance in fracturing fluid technology was the development of cross-linked gels. The first cross-linked gels were developed in 1968 (Ely, 1985). When cross-linking agents are added to linear gels, the result is a complex, high-viscosity fracturing fluid that provides higher proppant transport performance than do linear gels (Messina, Inc. Web site, 2001; Ely, 1985; Halliburton Inc., Virginia Site Visit, 2001). Cross-linking reduces the need for fluid thickener and extends the viscous life of the fluid indefinitely. The fracturing fluid remains viscous until a breaking agent is introduced to break the cross-linker and, eventually, the polymer. Although cross-linkers make the fluid more expensive, they can considerably improve hydraulic fracturing performance, hence increasing coalbed methane well production rates.

Cross-linked gels are typically metal ion-cross-linked guar (Ely, 1985). Service companies have used metal ions such as chromium, aluminum, titanium, and other metal ions to achieve cross-linking (Ely, 1985). In 1973, low-residue (cleaner) forms of cross-linked gels, such as cross-linked hydroxypropylguar, were developed (Ely, 1985).

According to MSDSs summarized in Table 4-1, cross-linked gels may contain boric acid, sodium tetraborate decahydrate, ethylene glycol, and monoethylamine. These constituents are hazardous in their undiluted form and can cause kidney, liver, heart, blood, and brain damage through prolonged or repeated exposure. According to a BLM environmental impact statement, cross-linkers may contain hazardous constituents such as ammonium chloride, potassium hydroxide, zirconium nitrate, and zirconium sulfate (U.S. Department of the Interior, CO State BLM, 1998). Concentrations of these compounds in the fracturing fluids were not reported in the impact statement. The final concentration of cross-linkers is typically 1 to 2 gallons of cross-linker per 1,000 gallons of gel (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001).

4.2.2 Foamed Gels

Foam fracturing technology uses foam bubbles to transport and place proppant into fractures. The most widely used foam fracturing fluids employ nitrogen or carbon dioxide as their base gas. Incorporating inert gases with foaming agents and water reduces the amount of fracturing liquid required. Foamed gels use fracturing fluids with higher proppant concentrations to achieve highly effective fracturing. The gas bubbles in the foam fill voids that would otherwise be filled by fracturing fluid. The high concentrations of proppant allow for an approximately 75-percent reduction in the overall amount of fluid that would be necessary using a conventional linear or cross-linked gel (Ely, 1985; Halliburton, Inc., Virginia Site Visit, 2001). Foaming agents can be used in conjunction with gelled fluids to achieve an extremely effective fracturing fluid (Halliburton, Inc., Virginia Site Visit, 2001).

Foam emulsions experience high leakoff; therefore, typical protocol involves the addition of fluid-loss agents, such as fine sands (Ely, 1985; Halliburton, Virginia Site Visit, 2001). Foaming agents suspend air, nitrogen, or carbon dioxide within the aqueous phase of a fracturing treatment. The gas/liquid ratio determines if a fluid will be true foam or simply a gas-energized liquid (Ely, 1985). Carbon dioxide can be injected as a liquid, whereas nitrogen must be injected as a gas to prevent freezing (Halliburton, Inc., Virginia Site Visit, 2001).

According to the MSDSs summarized in Table 4-1, foaming agents can contain diethanolamine and alcohols such as isopropanol, ethanol, and 2-butoxyethanol. They can also contain hazardous substances including glycol ethers (U.S. Department of the Interior, CO State BLM, 1998). One of the foaming agent products listed in Table 4-1 can cause negative liver and kidney effects, although the actual component causing these effects is not specified on the MSDS. The final concentration is typically 3 gallons of foamer per 1,000 gallons of gel (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001).

4.2.3 Water & Potassium Chloride Water Treatments

Many service companies use groundwater pumped directly from the formation or treated water for their fracturing jobs. In some coalbed methane well stimulations, proppants are not needed to prop fractures open, so simple water or slightly thickened water can be a cost-effective substitute for an expensive polymer or foam-based fracturing fluid with proppant (Ely, 1985). Hydraulic fracturing performance is not exceptional with plain water, but, in some cases, the production rates achieved are adequate. Plain water has a lower viscosity than gelled water, which reduces proppant transport capacity.

Similar to plain water, another fracturing fluid uses water with potassium chloride (KCl) in addition to small quantities of gelling agents, polymers, and/or surfactants (Ely, 1985). Potassium chloride is harmless if ingested at low concentrations.

4.2.4 Acids

Acids are used in limestone formations that overlay or are interbedded within coals to dissolve the rock and create a conduit through which formation water and coalbed methane can travel (Ely, 1985). Typically, the acidic stimulation fluid is hydrochloric acid or a combination of hydrochloric and acetic or formic acid. For acid fracturing to be successful, thousands of gallons of acid must be pumped far into the formation to etch the face of the fracture (Ely, 1985). Some of the cellulose derivatives used as gelling agents in water and water/methanol fluids can be used in acidic fluids to increase treatment distance (Ely, 1985). As discussed in section 4.2.5, acids may also be used as a component of breaker fluids.

In addition, acid can be used to clean up perforations of the cement surrounding the well casing prior to fracturing fluid injection (Halliburton, Inc., Virginia Site Visit, 2001; Halliburton, Inc., 2002). The cement is perforated at the desired zone of injection to ease fracturing fluid flow into the formation (Halliburton, Inc., Virginia Site Visit, 2001; Halliburton, Inc., 2002).

Table 4-1 provides information on formic and hydrochloric acids. Acids are corrosive, and can be extremely hazardous in concentrated form. Acids are substantially diluted with water-based or water-and-gas-based fluids prior to injection into the subsurface. The injected concentration is typically 1,000 times weaker than the concentrated versions presented in the product MSDSs (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001).

4.2.5 Fluid Additives

Several fluid additives have been developed to enhance the efficiency and increase the success of fracturing fluid treatments. The major categories of these additives are defined and briefly described in the following sections.

Breakers

Breaker fluids are used to degrade the fracturing fluid viscosity, which helps to enhance post-fracturing fluid recovery, or flowback. Breakers can be mixed with the fracturing fluid during pumping, or they can be introduced later as an independent fluid. There are a variety of breaker types including time-release and temperature-dependent types. Most breakers are typically acids, oxidizers, or enzymes (Messina, Inc. Web site, 2001). According to a BLM environmental impact statement, breakers may contain hazardous constituents, including ammonium persulfate, ammonium sulphate, copper compounds, ethylene glycol, and glycol ethers (U.S. Department of the Interior, CO State BLM, 1998). Concentrations of these compounds in the fracturing fluids were not presented in the environmental impact statement.

Biocides

One hydraulic fracturing design problem that arises when using organic polymers in fracturing fluids is the incidence of bacterial growth within the fluids. Due to the presence of organic constituents, the fracturing fluids provide a medium for bacterial growth. As the bacteria grow, they secrete enzymes that break down the gelling agent, which reduces the viscosity of the fracturing fluid. Reduced viscosity translates into poor proppant placement and poor fracturing performance. To alleviate this degradation in performance, biocides, bactericides, or microbicides are added to the mixing tanks with the polymeric gelling agents to kill any existing microorganisms (e.g., sulfate-reducing bacteria, slime-forming bacteria, algae), and to inhibit bacterial growth and deleterious enzyme production. Bactericides are typically hazardous by nature (Messina, Inc. Web site, 2001). They may contain hazardous constituents, including polycyclic organic matter (POM) and polynuclear aromatic hydrocarbons (PAHs) (U.S. Department of the Interior, CO State BLM, 1998).

Information from MSDSs for a biocide and a microbicide is summarized in Table 4-1. These concentrated products are substantially diluted prior to injection into the subsurface. Typical dilution in the make-up water is 0.1 to 0.2 gallons of microbicide in 1,000 gallons of water (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001).

Fluid-Loss Additives

Fluid-loss additives restrict leakoff of the fracturing fluid into the exposed rock at the fracture face. Because the additives prevent excessive leakoff, fracturing fluid effectiveness and integrity are maintained. Fluid-loss additives of the past and present include bridging materials such as 100 mesh sand, 100 mesh soluble resin, and silica flour, or plastering materials such as starch blends, talc silica flour, and clay (Ely, 1985).

Friction Reducers

To optimize the fracturing process, water-based fluids must be pumped at maximum rates and fluids must be injected at maximum pressures. Increasing flow velocities and pressures in this manner can lead to undesirable levels of friction within the injection well and the fracture itself. In order to minimize friction, friction reducers are added to water-based fracturing fluids. The friction reducers are typically latex polymers or copolymers of acrylamides. They are added to slick water treatments (water with solvent) at concentrations of 0.25 to 2.0 pounds per 1,000 gallons (Ely, 1985). Some examples of friction reducers are oil-soluble anionic liquid, cationic polyacrilate liquid, and cationic friction reducer (Messina, Inc. Web site, 2001).

Acid Corrosion Inhibitors

Corrosion inhibitors are required in acid fluid mixtures because acids will corrode steel tubing, well casings, tools, and tanks. The solvent acetone is a common additive in corrosion inhibitors (GRI, 1996). Information from MSDSs for acid inhibitors is summarized in Table 4-1. These products can affect the liver, kidney, heart, central nervous system, and lungs. They are quite hazardous in their undiluted form. These products are diluted to a concentration of 1 gallon per 1,000 gallons of make-up water and acid mixture (Halliburton, Inc., Virginia Site Visit, 2001; Schlumberger, Ltd., 2001). Acids and acid corrosion inhibitors are used in very small quantities in coalbed methane fracturing operations (500 to 2,000 gallons per treatment).

4.2.6 Proppants

The purpose of a proppant is to prop open a hydraulic fracture. An ideal proppant should produce maximum permeability in a fracture. Fracture permeability is a function of proppant grain roundness, proppant purity, and crush strength. Larger proppant volumes allow for wider fractures, which facilitate more rapid flowback to the production well. Over a period of 30 minutes, 4,500 to 15,000 gallons of fracturing fluid will typically transport and place approximately 11,000 to 25,000 pounds of proppant into the fracture (Powell et al., 1999).

Table 4-1: Characteristics of Undiluted Chemicals Found in Hydraulic Fracturing Fluids (Based on MSDSs)

Product	Chemical Composition Information[1]	Hazards Information	Toxicological Information[2]	Ecological Information
Linear gel delivery system	1) 30-60% by wt. Guar gum derivative 2) 60-100% by wt. Diesel	• Harmful if swallowed • Combustible	• Chronic effects/Carcinogenicity – contains diesel, a petroleum distillate and known carcinogen • Causes eye, skin, respiratory irritation • Can cause skin disorders • Can be fatal if ingested	Slowly biodegradable
Water gelling agent	1) 60-100% by wt. Guar gum 2) 5-10% by wt. Water 3) 0.5-1.5% by wt. Fumaric acid	None	May be mildly irritating to eyes	Biodegradable
Linear gel polymer	1) <2% by wt. Fumaric acid 2) <2% by wt. Adipic acid	Flammable vapors	Can cause eye, skin and respiratory tract irritation	Not determined
Linear gel polymer slurry	1) 30-60% by wt. Diesel oil #2	• Causes irritation if swallowed • Flammable	• Carcinogenicity – Possible cancer hazard based on animal data; diesel is listed as a category 3 carcinogen in EC Annex I • May cause pain, redness, dermatitis	Partially biodegradable
Crosslinker	1) 10-30% by wt. Boric Acid 2) 10-30% by wt. Ethylene Glycol 3) 10-30% by wt. Monoethanolamine	• Harmful if swallowed • Combustible	• Chronic effects/Carcinogenicity EG may cause liver, heart, brain reproductive system and kidney damage, birth defects (embryo and fetus toxicity) • Causes eye, skin, respiratory irritation • Can cause skin disorders and eye ailments	Not determined
Crosslinker	1) 10-30% by wt. Sodium tetraborate decahydrate	May be mildly irritating: • to eyes and skin • if swallowed	May be mildly irritating	• Partially biodegradable • Low fish toxicity
Foaming agent	1) 10-30% by wt. Isopropanol 2) 10-30% by wt. Salt of alkyl amines 3) 1-5% by wt. Diethanolamine	• Harmful if swallowed • Highly flammable	• Chronic effects/Carcinogenicity – may cause liver and kidney effects • Causes eye, skin, respiratory irritation • Can cause skin disorders and eye ailments	Not determined
Foaming agent	1) 10-30% by wt. Ethanol 2) 10-30% by wt. 2-Butoxyethanol 3) 25-55% by wt. Ester salt 4) 0.1-1% by wt. Polyglycol ether 5) 10-30% by wt. Water	Harmful if swallowed or absorbed through skin	• May cause nausea, headache, narcosis • May be mildly irritating	Harmful to aquatic organisms
Acid treatment - hydrochloric acid	1) 30-60% by wt. Hydrochloric acid	• May cause eye, skin and respiratory burns • Harmful if swallowed	• Chronic effects/Carcinogenicity – prolonged exposure can cause erosion of teeth • Causes severe burns, and skin disorders	Not determined
Acid treatment - formic acid	1) 85% by wt. Formic acid	• May cause mouth, throat, stomach, skin and respiratory tract burns • May cause genetic changes	• May cause heritable genetic damage in humans • Causes severe burns • Causes tissue damage	Not determined
Breaker Fluid	1) 60-100% by wt. Diammonium peroxidisulphate	• May cause respiratory tract, eye or skin irritation • Harmful if swallowed	May cause redness, discomfort, pain, coughing, dermatitis	Not determined

Table 4-1: Characteristics of Undiluted Chemicals Found in Hydraulic Fracturing Fluids (Based on MSDSs)

Product	Chemical Composition Information[1]	Hazards Information	Toxicological Information[2]	Ecological Information
Microbicide	1) 40-100% by wt. 2-Bromo-2 nitro1,3-propanediol	• May cause eye and skin irritation	• Chronic effects/Carcinogenicity – not determined • Can cause permanent eye damage, skin disorders, abdominal pain, nausea, and diarrhea if ingested	Not determined
Biocide	1) 40-100% by wt. 2,2-Dibromo-3-nitrilopropionamide 2) 1-5% by wt. 2-Bromo-3-nitrilopropionamide	• Causes severe burns • Harmful if swallowed • May cause skin irritation; may cause allergic reaction upon repeated skin exposure	• Harmful if swallowed; large amounts may cause illness • Irritant; may cause pain or discomfort to mouth, throat, stomach; may cause pain, redness, dermatitis	Not determined
Acid corrosion inhibitor	1) 30-60% by wt. Methanol 2) 5-10% by wt. Propargyl alcohol	• May cause eye and skin irritation, headache, dizziness, blindness and central nervous system effects • May be fatal if swallowed • Flammable	• Chronic effects/Carcinogenicity – may cause eye, blood, lung, liver, kidney, heart, central nervous system and spleen damage • Causes severe eye, skin, respiratory irritation • Can cause skin disorders	Not determined
Acid corrosion inhibitor	1) 30-60% by wt. Pyridinium, 1-(Phenylmethyl)-, Ethyl methyl derivatives, Chlorides 2) 15% by wt. Thiourea 3) 5-10% Propan-2-ol 4) 1-5% Poly(oxy-1,2-ethanediyl)-nonylphenyl-hydroxy 5) 10-30% Water	• Cancer hazard (risk depends on duration and level of exposure) • Causes severe burns to respiratory tract, eyes, skin • Harmful if swallowed or absorbed through skin	• Carcinogenicity – Thiourea is known to cause cancer in animals, and possibly causes cancer in humans • Corrosive - short exposure can injure lungs, throat, and mucous membranes; can cause burns, pain, redness swelling and tissue damage	• Toxic to aquatic organisms • Partially biodegradable

[1] Information presented is for the pure product, which is significantly diluted prior to injection. MSDS chemical composition percentages may total more than 100%.
[2] Toxicity is concentration dependent.

4.3 The Fate and Transport of Stimulation Fluids Injected into Coal and Surrounding Rock During Hydraulic Fracturing of Coalbed Methane Reservoirs (with a Special Focus on Diesel Fuel)

Diesel fuel is sometimes a component of gelled fluids. Diesel fuel contains constituents of potential concern regulated under SDWA – benzene, toluene, ethylbenzene, and xylenes (i.e., BTEX compounds). The use of diesel fuel in fracturing fluids poses the greatest threat to USDWs because BTEX compounds in diesel fuel exceed the MCL at the point-of-injection (i.e. the subsurface location where fracturing fluids are initially injected).

The remainder of this section presents EPA's qualitative evaluation of the fate and transport of fracturing fluids injected into targeted coal layers in the subsurface during hydraulic fracturing. Although EPA's MOA with the three major service companies has largely eliminated diesel fuel from fracturing fluids injected directly into any USDWs, there may still be rare instances in which diesel fuel is used by other service companies or operators (USEPA, 2003). Therefore an evaluation of the use of diesel fuel in fracturing fluid, which also provides follow-up on the draft of this report published in August, 2002, is included in this chapter.

EPA revised its procedure for assessing the potential effects of fracturing fluid constituents on USDWs from the procedure presented in the August 2002 draft of this report as follows:

- EPA has revised the fraction of BTEX compounds in diesel used to estimate the point-of-injection concentrations from a single value to a documented broader range of values for the fraction of BTEX in diesel fuel. For example, the fraction of benzene in diesel was revised from 0.00006$g_{benzene}/g_{diesel}$ to a range with a minimum value of 0.000026 $g_{benzene}/g_{diesel}$ and a maximum value of 0.001 $g_{benzene}/g_{diesel}$. If the maximum value for benzene in diesel is used to estimate the concentration of benzene at the point-of-injection, the resulting estimate is 17 times higher than that presented in the Draft Report.

- In this report, EPA used more current values for two of the parameters used to estimate the point-of-injection concentrations of BTEX compounds. Specifically, the estimates in this report use a density of the diesel fuel-gel mixture of 0.87 g/mL compared to 0.84 g/mL in the Draft Report, and a fraction of diesel fuel in gel of 0.60 g_{diesel}/g_{gel} compared to 0.52 g_{diesel}/g_{gel} in the Draft Report. The use of these more current values does not affect the order of magnitude of the revised point-of-injection calculations.

- The August 2002 Draft Report included estimates of the concentration of benzene at an idealized, hypothetical edge of the fracture zone located 100 feet from the point-of-injection. Based on new information and stakeholder input, EPA concluded that the edge of fracture zone calculation is not an appropriate model for reasons including:

- Mined-through studies reviewed by EPA indicated that hydraulic fracturing injection fluids had traveled several hundred feet beyond the point-of-injection.

- The assumption of well-mixed concentrations within the idealized fracture zone is insufficient. One mined-through study indicated an observed concentration of gel in a fracture that was 15 times the injected concentration, with gel found to be hanging in stringy clumps in many fractures. The variability in gel distribution in hydraulic fractures indicates that the gel constituents are unlikely to be well mixed in groundwater.

- Based on more extensive review of the literature, the width of a typical fracture was estimated to be much thinner than that used in the Draft Report (0.1 inch versus 2 inches). The impact of the reduced width of a typical fracture is that the calculated volume of fluid that can fit within a fracture is less. After an initial volume calculation using the new width, EPA found that the volume of the space within the fracture area may not hold the volume of fluid pumped into the ground during a typical fracturing event. Therefore, EPA assumes that a greater volume of fracturing fluid must "leakoff" to intersecting smaller fractures than what was assumed in the Draft Report, or that fluid may move beyond the idealized, hypothetical "edge of fracture zone." This assumption is supported by field observations in mined-through studies, which indicate that fracturing fluids often take a stair-step transport path through the natural fracture system.

- In the Draft Report, EPA approximated the edge of fracture zone concentrations considering only dilution. Based on new information and stakeholder input on the Draft Report, EPA does not provide estimates of concentrations beyond the point-of-injection in the final report. Developing such concentration values with the precision required to compare them to MCLs would require the collection of significant amounts of site-specific data. This data in turn would be used to perform a formal risk assessment, considering numerous fate and transport scenarios. These activities are beyond the scope of this Phase I study.

The remainder of this section includes a discussion of the following components of EPA's analysis:

- The concentrations of BTEX at the point-of-injection.

- The percentage of fracturing fluids recovered during the recovery process.

- The influence of the capture zone.

- Factors that would increase or decrease the concentrations of BTEX remaining in the subsurface.

The first step in EPA's analysis of the potential threat to USDWs from the injection of fracturing fluids was calculating the point-of-injection concentrations of BTEX introduced from diesel fuel in the gelling agent. In Step 2, EPA considered factors that affect the degree to which hydraulic fracturing fluids are recovered. Steps 3, 4, and 5 provide analyses of physical/chemical, hydrogeological, and biological processes that could affect the fate and transport of hazardous chemicals introduced into coal seams. These steps are summarized in Table 4-2.

4.3.1 Point-of-Injection Calculation

The formulations or "recipes" for fracturing fluids differ among service companies and among sites; the amount of fracturing fluid used will also vary. Thus, a range of point-of-injection concentrations likely exists. According to field paperwork obtained during EPA's site visits (Consolidated Industrial Services, Inc., 2001; Halliburton, 2001) and information provided by three service company scientists (BJ Services, 2001; Halliburton, 2001; Schlumberger, Ltd., 2001), between 4 and 10 gallons of diesel-containing gelling agent are added to each 1,000 gallons of water used in hydraulic fracturing, when diesel is used. In addition, the fraction of BTEX in diesel may range by up to two orders of magnitude (Potter and Simmons, 1998). The lower and upper ranges of the values presented in Potter and Simmons (1998), as well as the three different values cited for gelling agent, were used to estimate point-of-injection concentrations for each of three fracturing fluid recipes (i.e., the ratio of fracturing gel to water). The resulting 24 point-of-injection calculations are provided in Table 4-2. These estimates provide the basis for a qualitative assessment regarding whether a Phase II study is warranted.

The following example illustrates how EPA estimated the concentrations of BTEX at the point-of-injection. Due to the variations in the recipe used by service companies, EPA's analysis begins with three different possible scenarios, as follows:

- Low ratio: 4 gallons of gel per 1,000 gallons of water
- Medium ratio: 6 gallons of gel per 1,000 gallons of water
- High ratio: 10 gallons of gel per 1,000 gallons of water

The concentration of benzene in fracturing fluid at the point-of-injection ($[benzene]_{inj}$) can be calculated using the following equation:

$$[benzene]_{inj} = (r_{gw}) \times (\rho_{dg}) \times (f_{dg}) \times (f_{bd}) \times (3{,}785\ mL_{gel}/gal_{gel}) \times (1\ gal_{water}/3.785\ L_{water}) \times (10^6\ \mu g/g)$$

Where:

r_{gw} = the ratio of diesel fuel-gel mixture to injection water ($gal_{gel}/1{,}000\ gal_{water}$) (4 $gal_{gel}/1{,}000gal_{water}$, 6$gal_{gel}/1{,}000\ gal_{water}$, and 10 $gal_{gel}/1{,}000\ gal_{water}$ represent the low, medium, and high ratios, respectively)

ρ_{dg} = the density of the diesel fuel-gel mixture (g_{gel}/mL_{gel}) = 0.84 g_{gel}/mL_{gel} (Halliburton, 2002)

f_{dg} = the fraction of diesel fuel in the gel (g_{diesel}/g_{gel}) = 0.52 g_{diesel}/g_{gel} (Halliburton, 2002)

f_{bd} = the fraction of benzene in diesel fuel ($g_{benzene}/g_{diesel}$) = 0.000026 to 0.001 $g_{benzene}/g_{diesel}$ (Potter and Simmons, 1998)

3,785 mL_{gel}/gal_{gel} = volume conversion factor

1 $gal_{water}/3.785\ L_{water}$ = volume conversion factor

$10^6\ \mu g/g$ = mass conversion factor

The concentration of benzene at the point-of-injection is calculated for the three gel/water ratios and the minimum and maximum concentrations of benzene in diesel fuel.

Using r_{gw} = 4 $gal_{gel}/1{,}000gal_{water}$ and f_{bd} = 0.000026 $g_{benzene}/g_{diesel}$ as an example, $[benzene]_{inj}$ is calculated as follows:

$$[benzene]_{inj} = (4\ gal_{gel}/1{,}000gal_{water}) \times (0.84\ g_{gel}/mL_{gel}) \times (0.52\ g_{diesel}/g_{gel}) \times (0.000026\ g_{benzene}/g_{diesel}) \times (3{,}785\ mL_{gel}/gal_{gel}) \times (1\ gal_{water}/3.785\ L_{water}) \times (1{,}000\ mL/L) \times (10^6\ \mu g/g) = 45\ \mu g/L$$

Table 4-2 summarizes the estimated injection concentrations of each BTEX constituent for the three assumed gel/water ratios and the minimum and maximum concentrations of BTEX in diesel fuel. It also presents the MCL for each compound. Many of the estimated concentrations of BTEX exceed the MCL at the point-of-injection.

Table 4-2 and the remainder of this section provide a qualitative assessment of the fate and transport processes that could attenuate the concentrations of BTEX in groundwater. Factors that would influence the availability of constituents of potential concern in fracturing fluids and decrease their concentrations include:

- Fluid Recovery - much of the fluid is eventually pumped back to the surface.

- Adsorption and entrapment - some of these constituents will undergo adsorption to the coal or become entrapped in the formation.

- Biodegradation - some fracturing fluid constituents, such as benzene, may undergo partial biodegradation.

4.3.2 Fracturing Fluid Recovery

Following the injection of fracturing fluids into the subsurface through coalbed methane wells (i.e., production wells), considerable amounts of the fracturing fluids are removed. During the recovery process, the injected fluids and ambient groundwater are pumped out of the formation through the production well to reduce formation pressure, enabling methane desorption and extraction. Palmer et al. (1991a) found that 61 percent of fracturing fluids were recovered based on samples collected from coalbed methane wells over a 19-day period. Their study predicted total recovery to be between 68 and 82 percent.

Palmer et al. (1991a) also discussed the possibility that a "check-valve effect" could trap some of the fracturing fluid on one side (i.e., upgradient, during production) of a collapsed or narrowed fracture, preventing the fluid from flowing back to the production well. This check-valve effect can occur in both natural and induced fractures when the fractures narrow again after the injection of fracturing fluid ceases, formation pressure decreases, and extraction of methane and groundwater begins.

Another factor preventing full recovery of injected fluids is the high injection pressure used during hydraulic fracturing operations. Fracturing fluids are forced into the subsurface under high pressure to enlarge and propagate existing fractures. The hydraulic gradients that cause fluids to flow away from the well during injection are much greater than the hydraulic gradients that occur during fluid recovery. As a result, some of the fracturing fluids will travel beyond the capture zone of the production well. The capture zone of a production well is the portion of the aquifer that contributes water to the well. The size of this zone will be affected by regional groundwater gradients, and by the drawdown caused by the well (USEPA, 1987). Fluids that flow beyond the capture zone of the production well generally are not recovered during the flowback process.

Gel contained in fracturing fluids may be unrecovered because its properties differ from that of water and highly soluble constituents of fracturing fluids. One mined-through study reviewed by EPA described evidence of gel clumps within many fractures (Steidl, 1993). One observed concentration of gel in a fracture was 15 times the injected concentration. When the fluids exist as undissolved gel, they may remain attached to the sides of the fractures or be trapped within smaller fractures or pores present in formations that surround the coalbed. The mined-through studies suggest that such fluids are unlikely to flow with groundwater during production, but they may present a source of gel constituents to flowing groundwater subsequent to fluid recovery. Fate and transport processes discussed later in this section can serve to reduce gel constituent concentrations that may result from trapped fluids. Mechanisms that may affect the recovery of fracturing fluids are discussed in section 3.3.2 of Chapter 3.

4.3.3 The Influence of the Capture Zone

The recovery process typically lasts approximately 10-20 years. During that time, groundwater within the production well's capture zone flows toward the production well. Assuming complete mixing, the predicted recovery of injected BTEX is between 68 and 82 percent (Palmer et al., 1991a). Thus, between 20 and 30 percent of the BTEX injected is expected to remain in the formation. It is reasonable to expect that most of the unrecovered fluid lies outside the capture zone and that the residual concentrations of BTEX within the capture zone are substantially less than the injection concentrations. Chemicals such as BTEX that are not recovered from within the capture zone during groundwater production may be diluted by groundwater that flows into the formation to replace production water. Additional attenuation from sorption and biodegradation may occur. Subsequent to production, dispersion and diffusion may serve to reduce residual BTEX concentrations. The fracturing fluids that flow beyond the capture zone are affected by regional groundwater flow and may be diluted by groundwater.

4.3.4 Fate and Transport Considerations

BTEX that has moved beyond the production well's capture zone is of the greatest concern. The fate and transport mechanisms that may affect BTEX concentrations beyond the capture zone are evaluated in this section. Factors that would likely decrease exposure concentrations and/or availability of BTEX include attenuation through groundwater flow dynamics, biological processes, and adsorption.

BTEX outside of the capture zone will likely be transported by groundwater flowing according to regional hydraulic gradients. This flow and transport are not influenced by production pumping. Nevertheless, mechanical dispersion will cause BTEX to spread horizontally and vertically in the aquifer, thereby reducing the concentrations. The degree of mechanical dispersion depends in part on the velocity of flow and increases with increased travel distance. Dilution can have a significant effect on the BTEX concentrations that could migrate to drinking water wells, especially if these wells are hundreds to thousands of feet from a hydraulically induced fracture. The process of molecular diffusion (i.e., the movement of BTEX from areas of higher to lower concentration due to the concentration differences) will further reduce BTEX concentrations. Collectively, mechanical dispersion and molecular diffusion are referred to as hydrodynamic dispersion (Fetter, 1994).

The biodegradation of diesel fuel constituents, including BTEX, has been studied in other geologic settings and laboratory studies and may lead to reductions in concentrations in coalbeds given the appropriate site conditions. No information was found about the occurrence of biodegradation or biodegradation rates of BTEX in coalbeds or surrounding rock. In order for biodegradation to occur, organisms capable of using BTEX as a food source must be present and conditions such as favorable pH, salinity, and sometimes the availability of oxygen, nitrogen, and phosphorous must be met to ensure bacterial survival. Generally, substantial benzene degradation occurs in aerobic environments. The levels of oxygen in a particular formation vary widely depending primarily on the depth of coalbeds from the surface. Data regarding biodegradation of benzene in an anaerobic environment indicates a range from no degradation to relatively slow degradation (USEPA, 1999).

As groundwater flows through a formation, chemicals such as BTEX may be retarded by adsorption. Although adsorption in coalbeds is likely, quantification of adsorption is difficult in the absence of laboratory or site-specific studies (due to competition for adsorption between BTEX and more lipophilic and less soluble constituents of diesel fuel and coal, and fracture thickness). Other processes, such as desorption of BTEX from the coal surface, and dissolution of BTEX from the gel phase may play a role in BTEX transport. Entrapment of gel in pore spaces and fractures may also influence the degree to which BTEX is available to groundwater. In some cases, the gel may be entrapped in such a way that it is neither available to flow back towards the production well nor flow towards a USDW in response to regional groundwater gradients.

According to the information listed on MSDSs provided to EPA, several of the constituents of potential concern listed in Table 4-1 can have toxic effects when people are exposed to sufficiently high concentrations through the susceptible route(s) of exposure (i.e., inhalation, ingestion, skin contact). However, only the BTEX compounds originating from diesel fuel are regulated under SDWA. None of the other constituents in Table 4-1 appear on the Agency's draft Contaminant Candidate List (CCL). The drinking water CCL is the primary source of priority contaminants for evaluation by EPA's drinking water program. Contaminants on the CCL are known or anticipated to occur in public water systems and may require regulations under SDWA. Information on the GSA study is available at http://www.epa.gov/fedrgstr/EPA-WATER/2004/April/Day-02/w7416.htm**.**

Further, EPA does not believe that the other Table 4-1 constituents potentially contained in fracturing fluids are introduced through coalbed methane fracturing in concentrations high enough to pose a significant threat to USDWs. First, it is EPA's understanding, based on conversations with field engineers and on witnessing three separate fracturing events, that fracturing fluids used for coalbed methane fracturing do not contain most of the constituents listed in Table 4-1. Second, if the Table 4-1 constituents were used, EPA believes some of the same hydrodynamic phenomena listed in steps 2 and 4 (flowback, dilution and dispersion), step 3 (adsorption and entrapment), and potentially step 5 (biodegradation) would minimize the possibility that chemicals included in the fracturing fluids would adversely affect USDWs.

Table 4-2: Estimated Concentrations of Diesel Contaminants in Fracturing Fluids at the Point-of-Injection and Factors Affecting Their Concentration and Movement in Groundwater

Point-of-Injection (POI) Calculation[1]						Factors Affecting the Concentration and Movement of Fluids in Groundwater			
Step 1						Step 2	Step 3	Step 4	Step 5
Recipe (gallons of gel per 1,000 gallons of water)	Chemical (MCL µg/L)	Fraction of Chemical in Diesel		Point-of-Injection Concentration (µg/L)[2]		Influence of Pumping Well Within the Capture Zone	Adsorption and Entrapment	Dilution and Dispersion	Biological Degradation
		Min.	Max.	Min.	Max.				
4	Benzene 5	0.000026	0.001	45	1,700	Movement of groundwater will be toward production well during its operation (about 10 to 20 years), assumes fluid recovered during pumping to be between 68% and 82% (Palmer et al., 1991a)	Adsorption likely to occur in coalbeds, dependent on width of fractures and flow or diffusion into coal matrix. Desorption may act as a continuing source of BTEX to groundwater. Adsorption less likely in surrounding strata such as shale and sandstone. Entrapment of gel may reduce the availability of BTEX to the surrounding groundwater.	Unrecovered BTEX that may be in pore spaces of formation(s) can be diluted by flow of clean groundwater through pore spaces or it may diffuse from pore spaces. Dilution may significantly reduce BTEX concentrations available to drinking water wells, especially when they are great distances from the hydraulic fracture.	If indigenous microorganisms at the site are capable of anaerobic degradation of BTEX, partial biodegradation may be a relevant attenuation mechanism (Haener, et al., 1996; Hess et al., 1997; Aronson and Howard, 1997; Tan et al., 2002).
6				68	2,600				
10				110	4,400				
4	Ethyl benzene 700	0.00007	0.002	120	3,500				
6				180	5,200				
10				310	8,700				
4	Toluene 1,000	0.000069	0.007	120	12,000				
6				180	18,000				
10				300	31,000				
4	Xylenes 10,000	0.00019[3]	0.006[3]	330	10,000				
6				500	15,000				
10				830	26,000				

[1] Using benzene as an example: $[\text{benzene}]_{inj} = (r_{gw}) \times (\rho_{fg}) \times (f_{dg}) \times (f_{bd}) \times (3{,}785\ mL_{gel}/gal_{gel}) \times (1\ gal_{water}/3.785\ L_{water}) \times (10^6\ \mu g/g)$, where:

r_{gw} = the ratio of gel to injection water ($gal_{gel}/1{,}000\ gal_{water}$) = 4 $gal_{gel}/1{,}000 gal_{water}$, 6 $gal_{gel}/1{,}000\ gal_{water}$ and 10 $gal_{gel}/1{,}000\ gal_{water}$

ρ_{fg} = the density of the diesel fuel-gel mixture (g_{gel}/mL_{gel}) = 0.84 g_{gel}/mL_{gel} (Halliburton, 2002)

f_{dg} = the fraction of diesel fuel in the gel (g_{diesel}/g_{gel}) = 0.52 g_{diesel}/g_{gel} (Halliburton, 2002)

f_{bd} = the fraction of benzene in diesel fuel ($g_{benzene}/g_{diesel}$) = 0.000026 to 0.001 $g_{benzene}/g_{diesel}$

Conversion factors: 3,785 mL_{gel}/gal_{gel} = volume conversion factor; 1 $gal_{water}/3.785\ L_{water}$ = volume conversion factor; $10^6\ \mu g/g$ = mass conversion factor.

[2] Values are rounded to two significant digits.

[3] Represents sum of meta-/para- and ortho-isomer analyses, since only one result was reported by Potter and Simmons for total xylenes.

4.4 Summary

Fracture engineers select fracturing fluids based on site-specific characteristics including formation geology, field production characteristics, and economics. Hydraulic fracturing operations vary widely in the types of fracturing fluids used, the volumes of fluid required, and the pump rates at which they are injected. Based on the information EPA collected, water or nitrogen foam frequently constitutes the solute in fracturing fluids used for coalbed methane stimulation. Other components of fracturing fluids used to stimulate coalbed methane wells may contain only benign ingredients, but in some cases, they contain constituents such as diesel fuel that can be hazardous in their undiluted forms. Fracturing fluids are significantly diluted prior to injection.

Water with a simple sand proppant can be adequate to achieve a desired fracture at some sites. In some cases, water must be thickened to achieve higher proppant transport capabilities. Thickening can be achieved by using linear or cross-linked gelling agents. Cross-linkers are costly additives compared to simple linear gels, but a fluid's fracturing efficiency can be greatly improved using cross-linkers. Foam fracturing fluids can be used to considerably reduce the amount of injected fluid required. The reduced water volume requirement translates into a space and cost savings at the treatment site because fewer water tanks are needed. Foam fracturing fluids also promote rapid flowback and reduced volumes of flowback water requiring disposal.

The use of diesel fuel in fracturing fluids poses the greatest potential threat to USDWs because the BTEX constituents in diesel fuel exceed the MCL at the point-of-injection. Given the concerns with the use of diesel fuel, EPA recently entered into agreements with three major service companies to eliminate diesel fuel from hydraulic fracturing fluids injected directly into USDWs to stimulate coalbed methane production. Industry representatives estimate that these three companies perform approximately 95 percent of the hydraulic fracturing projects in the United States.

In situations when diesel fuel is used in fracturing fluids, a number of factors would decrease the concentration and/or availability of BTEX. These factors include fluid recovery during flowback, adsorption, dilution and dispersion, and potentially biodegradation of constituents. For example, Palmer et al. (1991a) documented that only about one-third of fracturing fluid that is injected is expected to remain in the formation. EPA expects fate and transport considerations would minimize the possibility that chemicals included in fracturing fluids would adversely affect USDWs.

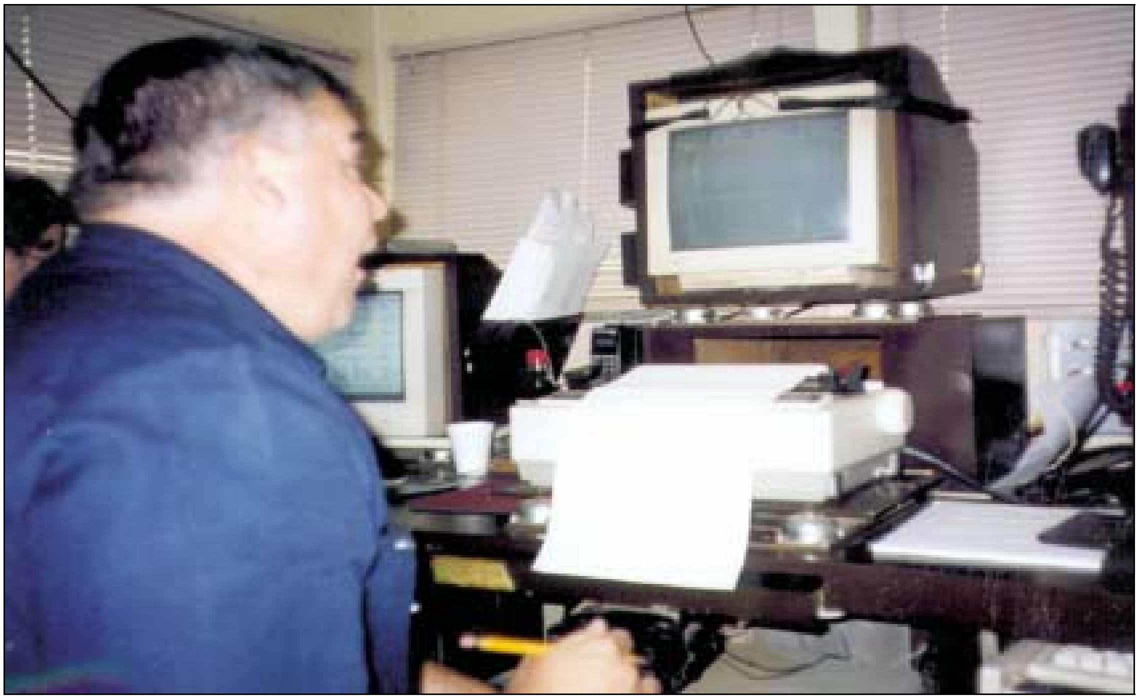
Figures 4-1 and 4-2. Liquid nitrogen tanker trucks transport gas to the site for nitrogen foam fracturing. Nitrogen will travel through pipes to be mixed with water and a foaming agent at the wellhead prior to injection. The foam is used to create and propagate the fracture deep within the targeted coal seam.

Figures 4-3 and 4-4.
Chemicals are stored on site in a support truck. Fracturing fluid additives such as the foaming agent can be pumped directly from storage containers to mix tanks.

Figure 4-5.
The fracturing fluid (water with additives) is stored on site in large, upright storage tanks. Each tank contains mix water imported from off-site, or formation water extracted directly from the gas well.

Figure 4-6.
Gelled water is pre-mixed in a truck-mounted mixing tank. Photograph shows a batch of linear, guar-based gel. This gel is used to transport the sand proppant into the fracture propagated by the nitrogen foam treatment.

Figure 4-7.
The fracturing fluids, additives, and proppant are pumped to the wellhead and mixed just prior to injection. The flow rate of each injected component is monitored carefully from an on-site control center.



Figures 4-8 and 4-9.
Electronic monitoring systems provide constant feedback to the service company's operators. Fluid flow rates and pressure buildup within the formation are monitored to ensure that fracture growth is safe and controlled.

Figures 4-10 and 4-11. Fluid that is extracted from the well is sprayed through a diffuser and stored in a lined trench until it is disposed of off-site or discharged.

Chapter 5
Summary of Coalbed Methane Basin Descriptions

As part of the Phase I study EPA conducted an extensive literature review to collect information regarding the major coal basins in the United States. Eleven major coal basins were identified in the United States and are shown in Figure 5-1 at the end of the chapter (those basins shaded in red have the highest coalbed methane production volumes). The goals of this review were to assess the following for each of the 11 major coal basins:

- The physical relationship between the coalbeds and the USDWs.
- Whether hydraulic fracturing is or has been used to stimulate coalbed methane wells in production basins.
- The types of fluids used to create the fractures.
- If possible, whether the potential for contaminants to enter a USDW exists.

This information is necessary to evaluate whether hydraulic fracturing is practiced within a basin and the types of fluids used in the fracturing process. More importantly, this information establishes whether the coal formations lie within a USDW, creating the potential for hydraulic fracturing fluid injection to threaten USDWs. A USDW is not necessarily currently used for drinking water and may contain groundwater unsuitable for drinking without treatment. In some cases, very little information was uncovered by EPA regarding certain topics for some of the basins.

Each of the 11 major basins is described in this chapter and in Table 5-1 (immediately following section 5.12 of this chapter). In addition, a more comprehensive description of the geology, hydrology, and coalbed methane production activity for each basin is provided in Attachments 1 through 11 of this report.

5.1 The San Juan Basin

The San Juan Basin covers an area of about 7,500 square miles straddling the Colorado-New Mexico state line in the Four Corners region (Figure 5-1). It measures roughly 100 miles long north to south and 90 miles wide. The Continental Divide trends north to south along the east side of the basin.

The major coal-bearing unit in the San Juan Basin is known as the Fruitland Formation. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped in the underlying and adjacent Pictured Cliffs sandstone. Many wells are completed in both zones. The coals of the Fruitland Formation are very thick compared to coalbeds in eastern basins: the thickest coals range from 20 to over 40 feet. Total net thickness of all coalbeds ranges from 20 to over 80 feet throughout the San Juan Basin, compared to 5 to 15 feet in eastern basins.

Coalbed methane wells in the San Juan Basin range from 550 to 4,000 feet in depth, and about 2,550 wells were operating in 2001 (Colorado Oil and Gas Conservation Commission and New Mexico Oil Conservation Division, 2001). The San Juan Basin is the most productive coalbed methane basin in North America. In 1996, coalbed methane production there averaged about 800 thousand cubic feet per day per well and totaled over 800 billion cubic feet (Bcf) for that year (Stevens et al., 1996). This total rose to 925 Bcf in 2000 (GTI, 2002)).

The majority of coalbed methane development and hydraulic fracturing in the northern portion of the San Juan Basin takes place within a USDW. The waters in parts of the Fruitland Formation usually contain less than 10,000 mg/L TDS, which is the water quality criterion for a USDW. In the northern half of the formation, most waters contain less than 3,000 mg/L, and wells near the outcrop produce water that contains less than 500 mg/L TDS.

Fracturing fluids used in the San Juan Basin include hydrochloric acid; slick water (water mixed with solvent); linear and crosslinked gels; and, since 1992, nitrogen- or carbon dioxide-based foams (Harper et al., 1985; Jeu et al., 1988; Holditch et al., 1988; Palmer et al., 1993b; Choate et al., 1993). Data are not readily available concerning fracture growth and height within the Fruitland Formation.

5.2 The Black Warrior Basin

The Black Warrior Basin is the southernmost of the three basins that compose the Appalachian Coal Region of the eastern United States. The basin covers about 23,000 square miles in Alabama and Mississippi. It is approximately 230 miles long from west to east and approximately 188 miles wide from north to south (Figure 5-1). Basin coalbed methane production is limited to the bituminous coalfields of west-central Alabama, primarily in Jefferson and Tuscaloosa Counties.

Coalbed methane production in the Black Warrior Basin is confined to the Pennsylvanian-aged Pottsville Formation. The ancient coastline of prehistoric Alabama was characterized by 8 to 10 “coal-deposition cycles” of rising and falling sea levels. Each cycle features mudstone at the base of the cycle (deeper water) and coalbeds at the top (emergence). Most coalbed methane wells tap the Black Creek/Mary Lee/Pratt cycles and range from 350 to 2,500 feet deep (Holditch, 1990).

Coalbed methane production in the Black Warrior Basin is among the highest in the United States. In 1996, about 5,000 coalbed methane wells were permitted in Alabama. In 2000, this number increased to over 5,800 wells (Alabama Oil and Gas Board, 2002). Coalbed methane wells have production rates that range from less than 20 to more than 1 million cubic feet (Mcf) per day per well (Alabama Oil and Gas Board, 2002). Between 1980 and 2000, coalbed methane wells in Alabama produced roughly 1.2 trillion cubic feet (Tcf) of gas. According to GTI, annual gas production was 112 Bcf in 2000 (GTI, 2002).

Some portions of the Pottsville Formation contain waters that meet the quality criterion of less than 10,000 mg/L TDS for a USDW. According to the Alabama Oil and Gas Board, some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels considerably higher than 10,000 mg/L.

Early literature indicates that most of the wells in production in the early 1990s have been hydraulically fractured an average of two to six times to achieve acceptable production rates (Holditch et al., 1988; Holditch, 1990; Palmer et al., 1993a and 1993b).

5.3 The Piceance Basin

The Piceance Coal Basin is entirely within the northwest corner of the Colorado (Figure 5-1). The coalbed methane reservoirs are found in the Upper Cretaceous Mesaverde Group, which covers about 7,225 square miles of the basin.

The Mesaverde Group ranges in thickness from about 2,000 feet on the west to about 6,500 feet on the east side of the basin (Johnson, 1989). The depth to the methane-bearing Cameo-Wheeler-Fairfield coal zone is about 6,000 feet. Two-thirds of the coalbed methane occurs in coals deeper than 5,000 feet, and the Piceance Basin is one of the deepest coalbed methane areas in the United States (Quarterly Review, August 1993).

The depth of the coals in the Piceance Basin inhibits permeability, making it difficult to extract the coalbed methane. This, in turn, has slowed coalbed methane development in the basin. However, it is estimated that 80 trillion to 136 Tcf of coalbed methane are contained in the Cameo-Wheeler-Fairfield coal zone of the basin (Tyler et al., 1998). Total coalbed methane production was 1.2 Bcf in 2000 (GTI, 2002).

The Piceance Basin contains both alluvial and bedrock aquifers. Unconsolidated alluvial aquifers (narrow and thin deposits of sand and gravel formed primarily along stream courses) are the most productive aquifers in the Piceance Basin. The bedrock aquifers are known as the upper and lower Piceance Basin aquifer systems. The upper aquifer system is about 700 feet thick, and the lower aquifer system is about 900 feet thick. Water at depth in the Piceance Basin appears to be of poor quality, minimizing its chance of being designated a USDW. In general, the potable water wells in the Piceance Basin extend no further than 200 feet in depth, based on well records maintained by the Colorado Division of Water Resources. A composite water quality sample taken from 4,637 to 5,430 feet deep in the Cameo coal zone exhibited a TDS level of 15,500 mg/L (Graham, 2001).

Hydraulic fracturing is practiced in this basin. A variety of fluids are used for fracturing, including water with sand proppant and gelled water and sand. In some cases, hydraulic stimulations created multiple short (100-foot), fractures around the wells (Quarterly Review, August 1993).

It is unlikely that any USDWs and coals targeted for methane production (generally currently located at great depth, such as 4,000 feet below the ground surface and deeper) would coincide in this basin. The thousands of feet of stratigraphic separation between the coal gas bearing Cameo Zone and the lower aquifer system in the Green River Formation should prevent any of the effects from the hydrofracturing of gas-bearing strata from reaching either the upper or the lower bedrock aquifers.

Research suggests that exploration may target areas where groundwater circulation may enhance gas accumulation in the coal and associated sandstones (Tyler et al., 1998). Under these exploration and development conditions, a USDW located in shallower Cretaceous rocks near the margins of the basin could be affected by hydraulic fracturing. The depth of methane-bearing coals (about 6,000 feet) seems to indicate that, in the Piceance Basin, the chances of contaminating any overlying, shallower USDWs (no deeper than about 1,000 feet) from injection of hydraulic fracturing fluids and subsequent subsurface fluid transport are minimal. The coalbed methane producing Cameo Zone and the deepest known aquifer, the lower bedrock aquifer, have a stratigraphic separation of over 6,000 feet.

5.4 The Uinta Basin

The Uinta Coal Basin is mostly within eastern Utah; a very small portion of the basin is in northwestern Colorado (Figure 5-1). The basin covers approximately 14,450 square miles (Quarterly Review, August 1993). The Uinta Basin is stratigraphically continuous with the Piceance Basin of Colorado, but is structurally separated from it by the Douglas Creek Arch, an uplift near the Utah – Colorado state line.

Coal seams occur in the Cretaceous Mancos Shale and the Upper Cretaceous Mesaverde Group (Quarterly Review, 1993). Two major formations targeted for coalbed methane exploration are the Mancos Shale’s Ferron Sandstone Member, which include the coals most targeted (approximately 90 percent of the time) for exploration (Petzet, 1996) and the Mesaverde Group’s Blackhawk Formation, which contains about 14 coal zones (Petzet, 1996). The Ferron Coals are interbedded with sandstone and form a wedge of clastic sediment 150 to 750 feet thick. Depths to coal in the Ferron Sandstone range from 1,000 to over 7,000 feet below ground surface (Garrison et al., 1997). The Blackhawk Formation consists of coal seams interbedded with sandstone and a combination of shale and siltstone. Coals tapped in the Blackhawk Formation are 4,200 to 4,400 feet below the surface (Gloyn and Sommer, 1993).

Full-scale exploration in the Uinta Basin began in the 1990s (Quarterly Review, 1993). The database covering the Uinta Basin indicates that there are about 1,255 coalbed methane wells in production in the basin (Osborne, 2002). The coalbed methane potential of the Uinta Basin, revised by the Utah Geological Survey in the early 1990s, has been estimated to be between 8 trillion and more than 10 Tcf (Gloyn and Sommer, 1993).

At some locations, the groundwater in the Ferron Coals and Blackhawk Formations would not qualify as USDWs. According to the Utah Department of Natural Resources (DNR), Division of Oil, Gas and Mining, the water there varies greatly by location, each location having some TDS levels below and some above 10,000 mg/L (Utah DNR, 2002). In general, the quality of Blackhawk water is higher than Ferron water. For example, the most recent UIC application noted the combined quality of input water to be approximately 31,000 mg/L TDS for the Drunkards Wash Field (Ferron) and 9,286 mg/L TDS for the Castlegate Field (Blackhawk).

Fracturing fluid use is documented in the literature pertaining to the Uinta Basin. One company reported performing hydraulic fracturing stimulations using cross-linked borate gel with 250,000 pounds of proppant (Quarterly Review, 1993). Others report that they fractured wells with low-residue gel fracturing fluids and foams (Quarterly Review, 1993). GTI places the annual coalbed methane production in the Uinta Basin at 75.7 Bcf in 2000 (GTI, 2002).

The Blackhawk Formation is underlain by 300 feet of shale and sandstone, which separate it from the Castlegate Sandstone aquifer. It is underlain by similar geologic strata, which separate it from the Star Point Sandstone. Only in highly faulted areas is there a reasonable possibility that hydraulic fracturing fluids could migrate down to the Star Point Sandstone.

5.5 The Powder River Basin

The Powder River Basin is in northeastern Wyoming and southern Montana (Figure 5-1). The basin covers approximately 25,800 square miles (Larsen, 1989), approximately 75 percent of which is in Wyoming. Fifty percent of the Powder River Basin is believed to have the potential for coalbed methane production (Powder River Coalbed Methane Information Council, 2000). Annual production volume was estimated at 147 Bcf in 2000 (GTI, 2002). In 2002, wells in the Powder River Basin produced about 823 Mcf per day of coalbed methane (DOE, 2002).

Coalbeds in this region are interspersed at varying depths with sandstones, mudstone, conglomerate, limestone, and shale. The majority of the potentially productive coal zones range from about 450 feet to over 6,500 feet below ground surface (Montgomery, 1999). The uppermost formation is the Wasatch Formation, extending from land surface to 1,000 feet deep. Most coal seams in the Wasatch Formation are continuous and thin (6 feet or less). The Fort Union Formation lies directly below the Wasatch Formation and can be as much as 6,200 feet thick (Law et al., 1991). The coalbeds in this formation are typically most abundant in the upper portion, called the Tongue River member. This member is typically 1,500 to 1,800 feet thick, of which up to a composite total of 350 feet of coal can be found in various beds. The thickest of the individual coalbeds is over 200 feet (Flores and Bader, 1999). Recent estimates of coalbed methane reserves in the Powder River Basin range from 7 trillion to 40 Tcf (Montgomery, 1999; PRCMIC, 2000).

The Fort Union Formation that supplies municipal water to the City of Gillette is the same formation that contains the coals that are developed for coalbed methane. The coalbeds contain and transmit more water than the sandstones. The sandstones and coalbeds have been used for the production of both water and coalbed methane. The water produced from the coalbeds meets the quality criterion for USDWs of less than 10,000 mg/L TDS.

EPA's understanding is that hydraulic fracturing currently is not widely used in this region due to concerns about the potential for increased groundwater flow into the coalbed methane production wells (due to fracturing of impermeable formations adjacent to the coal, and the creation of a hydraulic connection to adjacent aquifers) and the collapse of open hole wells in coal upon dewatering. According to the available literature, where hydraulic fracturing has been used in this basin, it has not been an effective method for extracting methane. Hydraulic fracturing has been done primarily with water, or gelled water and sand, although recorded use of a solution of potassium chloride was identified in the literature.

5.6 The Central Appalachian Basin

The Central Appalachian Coal Basin is the middle of three basins that compose the Appalachian Coal Region of the eastern United States. It includes parts of Kentucky, Tennessee, Virginia, and West Virginia (Figure 5-1) and covers approximately 23,000 square miles. The greatest potential for methane development is in a small, 3,000-square-mile area in southwest Virginia and south central West Virginia (Kelafant, et al., 1988).

The coal basin consists of six Pennsylvanian age coal seams (Zebrowitz et al., 1991, and Zuber, 1998). These coal seams typically occur as multiple coalbeds or seams that are widely distributed (Zuber, 1998). The coal seams, from oldest to youngest (West Virginia/Virginia name), are the Pocahontas No. 3, Pocahontas No. 4, Fire Creek/Lower Horsepen, Beckley/War Creek, Sewell/Lower Seaboard, and Iager/Jawbone (Kelafant et al., 1988). The Pocahontas coal seams include the Squire Jim and Nos. 1 to 7; Nos. 3 and 4 are the thickest and cover the most area. Most of the coalbed methane (2.7 Tcf) occurs in the Pocahontas seams (Kelafant et al., 1988). In southwest Virginia and south central West Virginia, target coal seams achieve their greatest thickness and occur at depths of about 1,000 to 2,000 feet (Kelafant et al., 1988).

The Nora Field in southwestern Virginia is one of the better-known coalbed methane production fields. According to the Virginia Division of Gas and Oil, over 700 coalbed methane wells were drilled in the Nora Field in 2002 (Virginia Division of Gas and Oil, 2002). The Virginia Division of Gas and Oil also indicated that, in 2002, more than 1,800 coalbed methane wells were drilled in southwestern Virginia's Buchanan County (VA Division of Gas and Oil, 2002.) GTI reported that the entire basin produced 52.9 Bcf of gas in 2000 (GTI, 2002).

Because most of the coal strata dip, a coalbed methane well's location in the basin may determine if hydraulic fracturing during the well's development will affect the water quality of surrounding USDW. For instance, on the northeastern side of the basin, the depth to the Pocahontas No. 3 coalbed is less than 500 feet. This depth gradually increases to over 2,000 feet farther westward across this portion of the basin, in the direction of the dip of the coal seam. Therefore, a well tapping this seam in the eastern portion of the basin may be within a USDW, but a well tapping the seam in the western portion of the basin may be below the base of a

USDW. In addition, the base of the freshwater is not flat, but rather undulating. These factors indicate that the relationship between a coalbed and a USDW must be determined on a site-specific basis.

Hydraulic fracturing is a common practice in this region. Foam and water are the fracturing fluids of choice, and sand serves as the proppant. Additives can include hydrochloric acid, scale inhibitors, and microbicides. Pocahontas Oil & Gas, a subsidiary of Consol Energy, Inc., invited EPA personnel to a well where a hydraulic fracturing treatment was being performed by Halliburton Energy Services, Inc. Halliburton staff said that typical fractures extend from 300 to 600 feet from the well bore in either direction, but that fractures have been known to extend from as few as 150 feet to as many as 1,500 feet in length (Halliburton Inc., Virginia Site Visit, 2001). According to the fracturing engineer on-site, fracture widths range from one-eighth of an inch to almost one and one-half inches (Halliburton, Inc., Virginia Site Visit, 2001).

Since some coalbed methane exploration has moved to shallower seams, the Commonwealth of Virginia has instituted a voluntary program concerning depths at which hydraulic fracturing may be performed (Virginia Division of Oil and Gas, 2002). The program involves an operator's determination of the elevation of the lowest topographic point and the elevation of the deepest water well within a 1,500-foot radius of any proposed extraction well (Wilson, 2001). Hydraulic fracturing should occur at least 500 feet beneath than the lower of these two points.

5.7 The Northern Appalachian Basin

The Northern Appalachian Coal Basin is the northernmost of the three basins that make up the Appalachian Coal Region of the eastern United States. It includes parts of Pennsylvania, West Virginia, Ohio, Kentucky, and Maryland (Figure 5-1). The basin lies completely within the Appalachian Plateau geomorphic province and covers approximately 43,700 square miles (Adams et al., 1984, as cited by Pennsylvania Department of Conservation and Natural Resources, 2002). The Northern Appalachian basin trends northeast to southwest. The Rome Trough, a major graben structure, forms the southeastern and southern structural boundaries. The basin is bounded on the northeast, north, and west by outcropping Pennsylvanian-aged sediments (Kelafant et al., 1988).

The six Pennsylvanian-aged coal zones composing the Northern Appalachian Coal Basin are the Brookville-Clarion, Kittanning, Freeport, Pittsburgh, Sewickley, and Waynesburg. These coal units are within the Pottsville, Allegheny, and the Monongahela Groups (Kelafant et al., 1988). Coal seam depths range from surface outcrops to as much as 2,000 feet below ground surface, with most coal occurring at depths shallower than 1,000 feet (Quarterly Review, 1993). These depth differences arise due to the dip of the coalbeds. The total thickness of the Pennsylvanian-aged coal system averages 25 feet; however, better developed seams within the coal zones can increase in thickness by up to twice the average (Quarterly Review, 1993).

Coalbed methane has been produced in commercial quantities from the Pittsburgh coalbed of the Northern Appalachian Coal Basin since 1932 (Lyons, 1997), after the discovery of the Big Run

Field in Wetzel County, West Virginia, in 1905 (Hunt and Steele, 1991). As of 1993, O'Brien Methane Production, Inc. had at least 20 wells in Pennsylvania's southern Indiana County (Quarterly Review, 1993). Coalbed methane production development in the Northern Appalachian Basin has lagged, however, due to insufficient reservoir knowledge, inadequate well-completion techniques, and coalbed methane ownership issues revolving around whether the gas is owned by the mineral owner or the oil and gas owner (Zebrowitz et al., 1991). Discharge of produced waters has also proven to be problematic (Lyons, 1997) for coalbed methane field operators in the Northern Appalachian Coal Basin. Total coalbed methane production stood at 1.41 Bcf in 2000 (GTI, 2002). As of October 2002, 185 coalbed methane wells were producing coalbed methane in Pennsylvania (Pennsylvania Department of Conservation and Natural Resources, 2002).

The Northern Appalachian Basin is situated in the Appalachian Plateau's physiographic province. The primary aquifer in this area is a Pennsylvanian sandstone aquifer underlain by limestone aquifers (USGS, 1984). Water quality data from eight historic Northern Appalachian Coal Basin projects show that estimated TDS levels ranged from 2,000 to 5,000 mg/L at depths of 500 to 1,025 feet below ground surface (Zebrowitz et al., 1991), well within EPA's water quality criterion of 10,000 mg/L TDS for a USDW (40 CFR §144.3). Depths to the bottoms of the USDWs vary greatly in the basin and are better determined on a site-specific basis.

Hydraulic fracturing fluids used in the Northern Appalachian Basin have included water and sand, and nitrogen foam and sand (Hunt and Steele, 1991). The Christopher Coal Company/Spindler Wells Project, which took place from 1952 to 1959, stimulated 1 well with 12 quarts of nitroglycerin (Hunt and Steele, 1991). In the Vesta Mines Project of Washington County, Pennsylvania, the United States Bureau of Mines used gelled water and sand to complete 5 wells in the Pittsburgh Seam (Hunt and Steele, 1991).

Because most of the coal strata dip, a well's location in a basin determines whether the well is coincident with a USDW. For example, in the Pittsburgh Coal Group in Pennsylvania, the depth to the top of the coal group varies from outcrop to about 1,200 feet in the very southwestern corner of the state (Kelafant et al., 1988). The approximate depth to the bottom of the USDW is 450 feet. Therefore, production wells operating down to approximately 450 feet could potentially be hydraulically connected to the USDW.

5.8 The Western Interior Coal Region

The Western Interior Coal Region comprises three coal basins, the Arkoma, the Cherokee, and the Forest City Basins, and encompasses portions of six states: Arkansas, Oklahoma, Kansas, Missouri, Nebraska, and Iowa (Figure 5-1). The Arkoma Basin covers about 13,500 square miles in Arkansas and Oklahoma. The Cherokee Basin is part of the Cherokee Platform Province, which covers approximately 26,500 square miles (Charpentier, 1995) in Oklahoma, Kansas, and Missouri. The Forest City Basin covers about 47,000 square miles (Quarterly Review, 1993) in Iowa, Kansas, Missouri, and Nebraska.

In the Arkoma Basin, major middle-Pennsylvanian coalbeds occur within the Hartshorne, McAlester, Savanna, and Boggy Formations (Quarterly Review, 1993). The Hartshorne coals of the Hartshorne Formation are the most important for methane production in the Arkoma Basin. Their depth ranges from 600 to 2,300 feet in two productive areas of southeastern Oklahoma (Quarterly Review, 1993). In the Cherokee Basin, the primary coal seams targeted by operators are the Riverton Coal of the Krebs Formation and the Weir-Pittsburg and Mulky coals of the Cabaniss Formation (Quarterly Review, 1993). The Riverton and Weir-Pittsburg seams are about 3 to 5 feet thick and range from 800 to 1,200 feet deep, while the Mulky Coal, which ranges up to 2 feet thick, occurs at depths of 600 to 1,000 feet (Quarterly Review, 1993). Individual coal seams in the Cherokee Group of the Forest City Basin range from a few inches to about 4 feet thick, with seams up to 6 feet thick (Brady, 2002; Smith, 2002). Depths to the top of the Cherokee Group coals range from approximately the surface to 230 feet below ground surface in the shallower portion of the basin, in southeastern Iowa, to about 1,220 feet in the deeper part of the basin, in northeastern Kansas (Bostic et al., 1993).

As of March 2000, there were 377 coalbed methane wells in the Arkoma Basin of eastern Oklahoma, ranging in depth from 589 to 3,726 feet (Oklahoma Geological Survey, 2001). The Arkoma Basin contains an estimated 1.58 to 3.55 Tcf of gas reserves, primarily in the Hartshorne coals (Quarterly Review, 1993). In the Cherokee Basin, unknown amounts of coalbed methane gas have been produced with conventional natural gas for over 50 years (Quarterly Review, 1993). Targeted coalbed methane production increased in the late 1980s, and at least 232 coalbed methane wells had been completed as of January 1993 (Quarterly Review, 1993). The Cherokee Basin contains an estimated 1.38 Mcf of gas per square mile (Stoeckinger, 1989) in the targeted Mulky, Weir-Pittsburg, and Riverton coal seams of the Cherokee Group (Quarterly Review, 1993). In total, the basin contains approximately 36.6 Bcf of gas. However, the Petroleum Technology Transfer Council (1999) indicates that there are nearly 10 Tcf of gas in eastern Kansas alone (PTTC, 1999). The Forest City Basin was relatively unexplored in 1993, with about 10 coalbed wells concentrated in Kansas' Atchison, Jefferson, Miami, Leavenworth, and Franklin Counties (Quarterly Review, 1993). The Forest City Basin contains an estimated 1 Tcf of gas (Nelson, 1999). For the entire region, coalbed methane production was 6.5 Bcf in 2000 (GTI, 2002).

According to the National Water Summary (1984), there are no principal aquifers in the portions of Oklahoma and Arkansas in the Arkoma Basin, only small alluvial aquifers bounding rivers. Water quality test results from the targeted Hartshorne seam in Oklahoma have shown the water to be highly saline (Quarterly Review, 1993). The base of fresh water in Arkansas is about 500 to 2,000 feet below ground surface (Cordova, 1963). However, Cordova (1963) does not define "fresh water." While the majority of the Cherokee Basin does not contain a principal aquifer, the Ozark and Douglas aquifers are contained within the basin (National Water Summary, 1984). The confined Ozark Aquifer, composed of weathered and sandy dolomites, typically contains water wells that extend from 500 to 1,800 feet in depth (National Water Summary, 1984). The usually unconfined Douglas Aquifer is a sandstone channel of the Pennsylvanian Age (National Water Summary, 1984). Wells are usually 5 to 400 feet deep in this aquifer. In Kansas, depth to the base of the Ozark Aquifer is roughly 1,750 feet below ground surface (Ozark Aquifer Base Map, 2001). In Oklahoma, the Cherokee Basin also contains the Garber-Wellington and

Vamoosa-Ada aquifers (National Water Summary, 1984). Water well depths in these two aquifers usually range from 100 to 900 feet (National Water Summary, 1984). The Forest City Basin contains the Jordan Aquifer, the Dakota Aquifer, and glacial drift, alluvial, and Paleozoic-aged rock aquifers. Wells in these aquifers commonly range in depth from 300 to 2,000 feet, 100 to 600 feet, 10 to 300 feet, 10 to 150 feet, and 30 to 2,200 feet, respectively (National Water Summary, 1984). Throughout the Western Interior Coal Region, water quality sampling has shown TDS levels to range from 500 to 40,000 mg/L (Missouri Division of Geological Survey and Water Resources, 1967).

Hydraulic fracturing is common in the Western Interior Coal Basin. Fracturing fluids such as linear gel, acid, and nitrogen foam were used extensively in the Western Interior coal region before 1992, and slick water treatments became common in 1993. Hydraulic fracturing is still practiced in the basin.

Based on depths to the Hartshorne Coal (0 to 4,500 feet in Arkansas) and the base of fresh water (500 to 2,000 feet in Arkansas), it appears that coalbed methane extraction wells in the Arkoma Basin could be coincident with potential USDWs in Arkansas (Andrews et al., 1998; Cordova, 1963). Based on maps provided by the Oklahoma Corporation Commission (2001) showing the depths of the 10,000 mg/L TDS groundwater quality boundary in Oklahoma, coalbed methane wells and USDWs would most likely not coincide in Oklahoma. This is based on depths to coals typically greater than 1,000 feet (Andrews et al., 1998) and depths to the base of the USDW typically shallower than 900 feet (OCC Depth to Base of Treatable Water Map Series, 2001).

In the Cherokee Basin, coalbed methane wells targeting the Cherokee Group coals in Kansas coincide with USDWs. Depths to the top of coalbeds range from 800 to 1,200 feet (Quarterly Review, 1993) while the depth to the base of fresh water is estimated at 1,750 feet (Mapped information from the Kansas Data Access and Support Center (DASC), 2001a). More information concerning water quality is required prior to any determination of coalbed methane well/USDW co-location in Missouri. However, current levels of coalbed methane activity are minimal in that state. In addition, since only a very small portion of the Cherokee Basin falls within Missouri, this portion of the basin needs to be delineated more precisely to see which USDWs are in this small part of the basin. Last, in the Forest City Basin, there appears to be little relationship between water supplies and coalbeds that may be used for coalbed methane extraction. However, aquifer and well information from the National Water Summary (1984) indicates that a co-location of the two could exist in Nebraska. More information is needed to define the relationship between coalbeds and USDWs in the Forest City Basin.

5.9 The Raton Basin

The Raton Basin covers about 2,200 square miles in southeastern Colorado and northeastern New Mexico (Figure 5-1). It is the southernmost of several major coal-bearing basins along the eastern margin of the Rocky Mountains. The basin extends 80 miles north to south and as much as 50 miles east to west (Stevens et al., 1992). It is an elongate, asymmetric syncline, 20,000 to 25,000 feet thick in the deepest part.

There are two major coal formations in the Raton Basin, the Vermejo and the Raton. The Vermejo coals range from 5 to 35 feet thick, while the Raton coal layers range from 10 to more than 140 feet thick. Although the Raton Formation is much thicker and contains more coal than the Vermejo Formation, individual coal seams in the Raton are less continuous and generally thinner.

Methane resources for the basin have been estimated at approximately 10.2 Tcf in the Vermejo and Raton Formations (Stevens et al., 1992). As of 1992, about 114 coalbed methane exploration wells had been drilled in the basin (Quarterly Review, 1993). According to GTI, the average coalbed methane production rate of wells in the Raton Basin was close to 300 thousand cubic feet per day, and annual production in 2000 was 30.8 Bcf (GTI, 2002).

The coal seams of the Vermejo and Raton Formations developed for methane production also contain water that meets the criterion for a USDW. The underlying Trinidad Sandstone and other sandstone beds in the Vermejo and Raton Formations, as well as intrusive dikes and sills, also contain water of sufficient quality to be used as drinking water.

Coalbed methane well stimulation using hydraulic fracturing techniques is common in the Raton Basin. Records show that fracturing fluids used are typically gels and water with sand proppants. Hemborg (1998) showed that in most cases water yield decreased dramatically as methane production continued over time. However, some wells exhibited increased water production as methane production continued or increased. Two causal factors were suggested (Hemborg, 1998) for the rise in water production:

1. Well stimulation had increased the well’s zone of capture to include adjacent water-bearing sills or sandstones that were hydraulically connected to recharge areas, or;

2. Well stimulation had created a connection between the coal seams and the underlying water-bearing Trinidad Sandstone.

5.10 The Sand Wash Basin

The Sand Wash Basin is in northwestern Colorado and southwestern Wyoming. It is part of the Greater Green River Coal Region, which includes the Washakie Basin, the Great Divide (Red Desert) Basin, and the Green River Basin (Figure 5-1). These sub-basins are separated by uplifts caused by deformation of the basement rock. For example, the Sand Wash Basin is separated from the adjacent Washakie Basin by the Cherokee Arch, an anticline ridge that runs east to west along the Colorado – Wyoming border. The Greater Green River Coal Region, in total, covers an area of approximately 21,000 square miles. The Sand Wash Basin covers approximately 5,600 square miles, primarily in Moffat and Routt Counties of Colorado.

The coal-bearing formations in the region include the Iles, Williams Fork, the Fort Union, and the Wasatch Formations. The total thickness of the coal seams in these formations can be up to 150 feet (Quarterly Review, 1993). Of all the formations, the Williams Fork is the most significant coal-bearing unit because it has the thickest and most extensive coalbeds. Coal-bearing strata are 5,000 feet deep along the basin's western portions and outcrop along its southern and eastern margins. The coal seams are interbedded with sandstones and shale. The thickest total coal deposits in the Williams Fork Formation, up to 129 feet, are centered on Craig, CO. These deposits are composed of several separate seams up to 25 feet thick interspersed between layers of sedimentary rock.

Coalbed methane resources in the Sand Wash Basin have been estimated at 101 Tcf. Approximately 90 percent of this gas is in the Williams Fork Formation. Approximately 24 Tcf of coalbed methane are located less than 6,000 feet below ground surface (Kaiser et al., 1994a). Some investigation and very limited commercial development of this resource have occurred, mostly in the late 1980s and early 1990s. Records from the Colorado Oil and Gas Commission indicate that approximately 31 Bcf of coalbed methane was produced in Moffat County during 1995 (Colorado Oil and Gas Conservation Commission, 2001). There appears to be no commercial production at present (GTI, 2002). Development of coalbed methane resources in the Sand Wash Basin has been slower than in many other areas due to limited economic viability. The need for extensive dewatering in most wells has been a limiting factor, compounded by relatively low coalbed methane recovery. In recent years, permits for new gas wells have been issued, indicating that there may be some continued interest in this area (Colorado GIS, 2001).

Kaiser and Scott (1994) summarized their extensive investigation of groundwater movement within the Fort Union and Mesaverde Group. The Mesaverde Group is a highly transmissive aquifer. The coal seams within the group may be the most permeable part of the aquifer. Lateral flow within the Fort Union Formation is slower. Groundwater quality in the basin varies greatly. Typically, chloride and TDS concentrations within the coal-bearing Mesaverde Group are low and potentially within potable ranges in the eastern portion of the basin, implying the existence of a USDW. TDS concentrations increase as the water migrates toward the central and western margins of the basin. TDS concentrations significantly higher than the 10,000 mg/L USDW water quality standard have been detected in the western portion of the basin.

The use of fracturing fluids, specifically water and sand proppant, has been reported for this basin. No record of any other fluid types has been noted. Although variable, the water quality within the fractured coals indicates the presence of USDWs within the coalbeds.

5.11 The Washington Coal Regions (Pacific and Central)

The Pacific Coal Region (Figure 5-1) is approximately 6,500 square miles and lies along the western and eastern flanks of the Cascade Range, from Canada into northern Oregon within the Puget downwarp structure. Bellingham, Seattle, Tacoma, and Olympia in Washington, and Portland, Oregon, lie in or adjacent to the sub-basins. The Central Coal Region (Figure 5-1) primarily lies within the Columbia Plateau, between the Cascade Range to the west and the Rocky Mountains to the east, in Idaho. This region extends from the Okanogan highlands to the north to the Blue Mountains to the south, and encompasses approximately 63,320 square miles.

The coal-bearing deposits of the Pacific and the Central Coal Regions are Cretaceous to Eocene Age and formed within fluvial and deltaic depositional environments prior to the uplift of the Cascade Mountain Range. The thick coalbeds of the Pacific and Central Basins are thought to result from peat accumulations in poorly drained swamps of the lower deltas, while the thinner coalbeds probably formed in the better drained upper deltas (Buckovic, 1979 as cited by Choate et al., 1980). The complex stratigraphy and structural deformation of the coals of the Pacific Coal Region are major obstacles to the exploration and development of gas fields. Although the coals of the Central Coal Region may not be as greatly deformed and unpredictable as those in the Pacific Coal Region, they are obscured by the Columbia River Basalt Group, in which individual basalt flows up to 300 feet thick can cover thousands of square miles.

The occurrence of methane in groundwater is one factor leading to the identification of the gas potential in Washington. Methane in groundwater occurs in the basalts, but only in confined aquifers (porous or fractured zones near the top or bottom of a basalt layer) and is thought to have migrated upward from underlying coalbeds. Choate et al. (1980) estimated coalbed methane resources for four target sub-basins representing 1,800 square miles of the Pacific Coal Region to be 0.3 trillion to 24 Tcf. Methane had been encountered in 67 oil and gas exploration wells drilled in this region by 1984. Gas was found at depths of less than 500 feet in 25 wells, less than 1,000 feet in 38 wells, and less than 2,000 feet in 50 wells. Pappajohn and Mitchell (1991) estimated the coalbed methane potential of the Central Coal Region to be more than 18 Bcf per square mile. The operation of the Rattlesnake Hills gas field between 1913 and 1941 in the western part of the Central Coal region indicates that greater potential for development may exist. According to the available literature, there were no producing fields in either the Pacific Coal Region or the Central Coal Region in Washington as of 2000 (GTI, 2001).

Water supply wells and irrigation wells in the Columbia River Basalts and water wells in numerous different lithologies in the Pacific Coal Region have been recognized as containing methane. Data demonstrating the co-location of a coal seam and a USDW were found for Pierce County, where methane gas test well results report TDS levels far less than the 10,000 mg/L USDW water quality threshold (Dion, 1984). These aquifers can be classified as USDWs. Data demonstrating the co-location of a coal seam and a USDW was found for Pierce County, where methane gas test well results report TDS levels of 1,330 to 1,660 mg/L, which is far less than the USDW classification limit (Dion, 1984). Development of methane in the Central Coal Region may have some impact on highly productive basalt aquifers already used as large sources of irrigation water for agriculture (Dion, 1984).

Hydraulic fracturing of coalbed methane wells using sand and nitrogen foam treatments has been documented (Quarterly Review August, 1993). However, optimal stimulation and completion methods for use in the structurally difficult Pacific gas region are yet to be applied and proven.

5.12 Summary

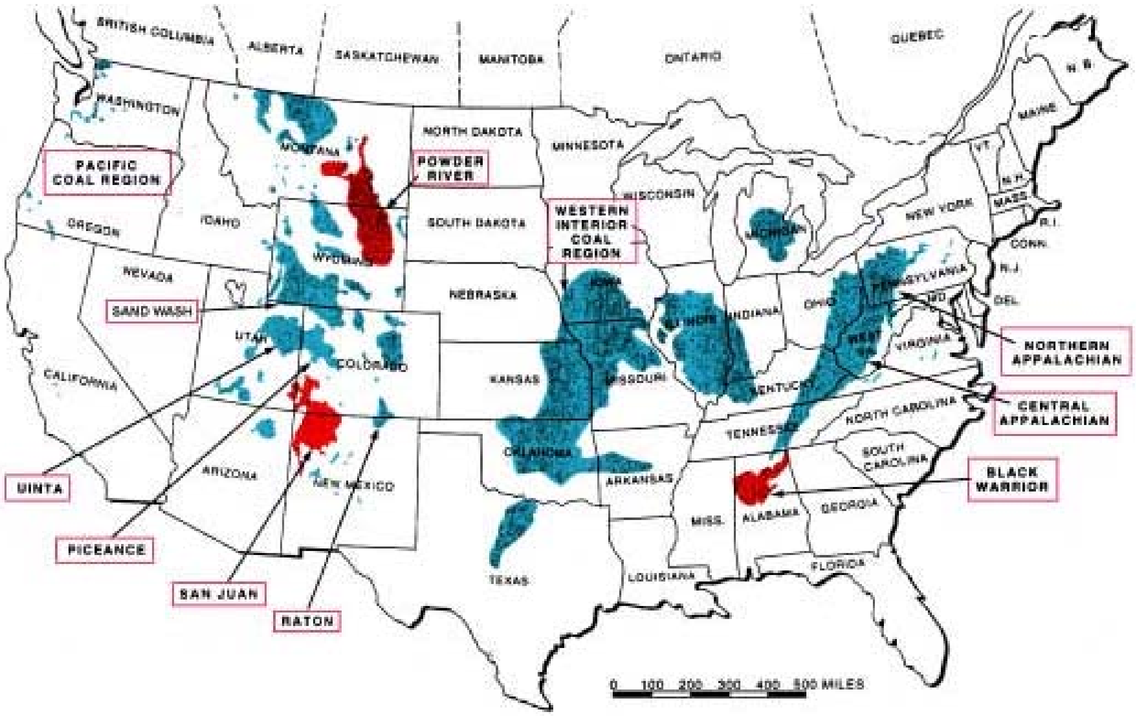
Hydraulic fracturing of coalbed methane production wells has been documented in each basin, although it is not widely practiced in the Powder River, Sand Wash Basin, or the Washington Coal Regions. Ten of the eleven major coal basins in the United States are located at least partially within USDWs. The literature also indicates that hydraulic fracturing may have increased or have the potential to increase the communication between coal seams and adjacent aquifers in two of the basins: the Powder River and Raton Basins. This may be the explanation for higher than expected withdrawal rates for production water in the Raton Basin following some fracturing treatments. In the Powder River Basin, concerns over the creation of such a hydraulic connection are cited as one reason why hydraulic fracturing of coalbed methane reservoirs is not widely practiced in the region.

Table 5-1. Evidence In Support of Coal-USDW Co-Location In U.S. Coal Basins

Basin	Are coalbeds found within the USDW?	Explanation and/or evidence
San Juan	Yes	A large area of the Fruitland system produces water containing less than 10,000 mg/L TDS, the water quality criterion for a USDW. Analyses taken from a selected coal well area show that (16 of 27 wells) produce water containing less than 10,000 mg/L TDS (Kaiser et al., 1994b).
Black Warrior	Yes	Some portions of the Pottsville Formation contain waters that meet the quality criteria of less than 10,000 mg/L TDS for a USDW. According to the Alabama Oil and Gas Board, some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels considerably higher than 10,000 mg/L (Alabama Oil and Gas Board, 2002). In the early 1990s, several authors reported fresh water production from coalbed wells at rates up to 30 gallons per minute (in Pashin et al., 1991; Ellard et al., 1992).
Piceance	Unlikely	The coalbed methane producing Cameo Coal Zone and the lower aquifer system in the Green River Formation are more than 6,000 feet apart. The coal zone, lies at great depth, roughly 6,000 feet below the ground surface in a large portion of the basin (Tyler et al., 1998). A composite water quality sample taken from 4,637 to 5,430 feet deep within the Cameo Coal Zone in the Williams Fork Formation exhibited a TDS level of 15,500 mg/L (Graham, 2001). The produced water from coalbed methane (CBM) extraction in the Piceance Basin is of such low quality that it must be disposed of in evaporation ponds; re-injected into the formation from which it came; or re-injected at even greater depths (Tessin, 2001).
Uinta	Likely	The water quality in the Ferron and Blackhawk varies greatly with location, each having TDS levels below and above 10,000 mg/L (Utah Department of Natural Resources, 2002)
Powder River	Yes	A report prepared by the United States Geological Survey (USGS) showed that samples of water co-produced from 47 CBM wells in the Powder River Basin all had TDS levels of less than 10,000 mg/L (Rice et al., 2000). The water produced by CBM wells in the Powder River Coal Field commonly meets drinking water standards. In fact, production waters such as these have been proposed as a separate or supplemental source for municipal drinking water in some areas (DeBruin et al., 2000).
Central Appalachian	Likely	Depths of coal groups are coincident with fresh water in at least two of the states within the overall basin (Kelafant et al., 1988; Wilson, 2001; Foster, 1980; Hopkins, 1966; USGS, 1973). Anecdotal information suggests that private wells in Virginia are screened within coal seams (Wilson 2001; VDMME, 2001).

Basin	Are coalbeds found within the USDW?	Explanation and/or evidence
Northern Appalachian	Yes	The depth of each coal group within the basin is coincident with the depths of USDWs (Kelafant et al., 1988; Platt, 2001; Foster, 1980; Hopkins, 1996; USGS, 1973; Sedam and Stein, 1970; USGS, 1971; Duigon, 1985). Water quality data from eight historic Northern Appalachian Coal Basin projects show TDS levels below 10,000 mg/L (Zebrowitz et al., 1991).
Western Interior:		
Arkoma	Yes (in Arkansas) Unlikely (in Oklahoma)	The depths of coalbeds within Arkansas are coincident with depths to fresh water (Andrews et al., 1998; Cordova, 1963; Friedman, 1982; Quarterly Review, 1993). Based on maps provided by the Oklahoma Corporation Commission (OCC) showing depths of the 10,000 mg/L TDS groundwater quality boundary in Oklahoma, the location of CBM wells and USDWs would most likely not coincide in that State. This is based on depths to coals typically greater than 1,000 feet (Andrews et al., 1998) and depths to the base of the USDW typically less than 900 feet (OCC Depth to Base of Treatable Water Map Series, 2001).
Cherokee	Yes	The depths of coalbeds in Kansas are coincident with depths to fresh water (Quarterly Review, 1993; Macfarlane, 2001; DASC, 2001a).
Forest City	Unlikely	The thinness of the aquifer suggests that there is significant separation from the deeper coalbeds within the basin (Bostic et al., 1993; DASC, 2001b; Condra and Reed, 1959; Flowerday et al., 1998).
Raton	Yes	Water quality results from CBM wells in the Raton Basin demonstrate TDS content of less than 10,000 mg/L. Nearly all wells surveyed show a TDS of less than 2,500 mg/L, and more than half had TDS of less than 1,000 mg/L (National Water Summary, 1984).
Sand Wash	Yes	Two gas companies produced water from coals that showed TDS levels below 10,000 mg/L. At Craig Dome in Moffat County, Cockrell Oil Corporation drilled 16 CBM wells. The wells yielded large volumes of fresh water with TDS <1,000 mg/L (Colorado Oil and Gas Commission, 2001). Fuelco was operating 11 wells along Cherokee arch. Water pumped from the wells contained 1,800 mg/L of TDS and was discharged to ground under a National Pollution Discharge Elimination System (NPDES) permit (Quarterly Review, 1993).
Pacific Coal and Central Region	Yes	Data from a 1984 study demonstrates the co-location of a coal seam and a USDW in Pierce County. Water quality information from four gas test wells indicates TDS levels between 1,330 and 1,660 mg/L, well below the 10,000 mg/L criterion (Dion, 1984). Wells in the Basalts commonly yield 150 to 3,000 gallons per minute. TDSs levels in the water produced generally range from 250 to 500 mg/L (Dion, 1984).

Figure 5-1. Locus Map of Major United States Coal Basins



Chapter 6
Water Quality Incidents

While Chapters 3 through 5 describe the theoretical and technical background for the potential contamination of USDWs from hydraulic fracturing fluid injection into coalbed methane wells, this chapter summarizes citizens' accounts of water quality and quantity incidents. These reports reflect the opinions of citizens living near coalbed methane operations who expressed concerns about contaminated drinking water wells and wells experiencing water quantity impacts such as reduced production. EPA has, through letters and telephone calls, contacted and been contacted by citizens who believed their water wells were affected by coalbed methane production in the San Juan, Black Warrior, Central Appalachian, and Powder River Basins. Stakeholders commenting on the study methodology (65 FR 45774 (USEPA, 2000)) asked that EPA consider personal experiences regarding coalbed methane impacts on drinking water wells in addition to data from formal studies.

As a result of the stakeholder comments, EPA published a request in the *Federal Register* (66 FR 39396 (USEPA, 2001)) for information from the public, as well as governmental and regulatory agencies, regarding incidents of groundwater contamination believed to be associated with hydraulic fracturing of coalbed methane wells. In addition, the Agency notified over 500 local and county agencies in areas of potential coalbed methane production making them aware of the *Federal Register* notice, but EPA received no information regarding citizen complaints from these officials. Therefore, EPA believes it knows the major geographic areas where citizens have reported problems that they attribute to coalbed methane development. These areas are concentrated in the most active basins: the San Juan, Black Warrior, Central Appalachian, and Powder River Basins. The Agency has included relevant information from the water quantity and quality incident reports that it has received.

Many of the reported incidents (such as impacts to water supply quantities or the effects of discharged groundwater extracted during the coalbed methane production process) are outside of the scope of SDWA and beyond the scope of this Phase I of the study. However, all incidences reported in response to the *Federal Register* request are included so that this study can be as inclusive as possible with respect to reported incidences and not inadvertently exclude a relevant reported incident. This study is specifically focused on assessing the potential for contamination of USDWs from the injection of hydraulic fracturing fluids into coalbed methane wells, and determining based on these findings, whether further study is warranted.

It is important to note that activities or conditions other than hydraulic fracturing fluid injection may account for some of the reported incidences of the contamination of drinking water wells. These potential causes include surface discharge of fracturing and production fluids, poorly sealed or poorly installed production wells, and improperly abandoned production wells.

For this phase of the study (Phase I), EPA consulted with state agencies to determine if they had received reports of groundwater problems, to learn of any follow-up steps typically taken by the state, and to determine the states' overall findings regarding any impacts that hydraulic fracturing of coalbed methane wells may have had on groundwater.

This chapter summarizes correspondence EPA has had with individual citizens and states, organized by basin, as follows:

- San Juan Basin (Colorado and New Mexico).
- Powder River Basin (Wyoming and Montana).
- Black Warrior Basin (Alabama).
- Central Appalachian Basin (Virginia and West Virginia).

6.1 The San Juan Basin (Colorado and New Mexico)

For over a decade, citizens in the San Juan Basin region have reported that coalbed methane development has resulted in increased concentrations of methane and hydrogen sulfide in their water wells. Other complaints about coalbed methane development include the loss of water, the appearance of anaerobic bacteria in water wells, and the transient appearance of particulates in well water. In conversations with EPA, most citizens and local government officials did not specify hydraulic fracturing as the cause of well water problems. Summaries of reported incidents and state follow-up are discussed in sections 6.1.1 and 6.1.2, respectively.

EPA reviewed the BLM study summarizing the history of methane seeps, citizen complaints, and follow-up investigations related to conventional gas and coalbed methane development in the San Juan Basin to determine if they contained information pertaining to coalbed methane hydraulic fracturing and its impact, if any, on the quality of water in drinking water aquifers in the basin. A summary of pertinent findings is provided in section 6.1.3.

6.1.1 Summary of Reported Incidents

- EPA spoke with a former county employee who, earlier in his career, had worked for Exxon performing hydraulic fracturing jobs (Holland, 1999). As a county employee, he took measurements for methane and hydrogen sulfide inside homes in response to citizen complaints. He indicated that there were no significant problems until the shallowest formation of coal (the Fruitland Formation) began being developed. He believed that the main route of contamination is from older, poorly cemented wells, and he estimated that hundreds of wells have been affected. He said the biggest problems associated with the apparent effects of coalbed methane development are the explosive levels of methane and the toxic levels of hydrogen sulfide in homes. In his opinion, this is due to the removal of water, rather than to hydraulic fracturing.

- The San Juan Citizens Alliance estimated that hundreds of private water wells have been affected by coalbed methane production in the area of Durango, CO. These complaints include the following:

  - A lawyer representing several Durango citizens whose wells were contaminated, allegedly due to coalbed methane development, said there have always been methane seeps in the river, which have manifested as bubbling water (McCord, 1999). In the early 1980s, however, people began to see increased concentrations of natural gas in their water wells shortly after companies began producing methane from the Fruitland Formation.

  - One individual reported that two of his wells were degraded because of increased methane levels. According to this individual, his neighbor's pump house door was blown off, presumably as a result of explosive levels of methane. Amoco bought three ranches after county officials tested indoor air and found extremely high levels of methane. This individual also told EPA staff that an area of the Southern Ute tribal land has increased levels of hydrogen sulfide at the surface. He reported he had also heard of black water due to pulverized coal.

  - Another private well owner claimed that her neighbors' wells are contaminated by gas infiltration from dewatering. First methane contaminates the well, then hydrogen sulfide, then anaerobic bacteria. She claimed that data exists showing that methane concentrations in water have increased by 1,000 parts per million (ppm).

- EPA Region 8 received letters from citizens concerned that coalbed methane development had contaminated their water with methane and hydrogen sulfide.

- During a visit to Durango, CO, EPA met with several citizens who claimed to have experienced problems with their water due to coalbed methane development. Most of the citizens experienced water loss, but two well owners from New Mexico claimed that the quality of their water was affected by hydraulic fracturing. According to their accounts, the water turned cloudy with grayish sediment a day or two after nearby fracturing events. Eventually, the well water returned to its normal appearance.

EPA also toured the area during that visit. EPA staff viewed areas where patches of grass and trees were turning brown and dying. In some places, large, old-growth trees located within the patch indicated that the area previously had prolonged normal soil conditions. Many citizens and some local officials believed that the areas suffered from increased methane and decreased air in the soil gas in the shallow root zone.

- A La Plata County official reported that citizens have called to complain that well water flow decreases when coalbed methane wells are hydraulically fractured (Keller, 1999). He reported that “a lot” of people are hauling water due to water loss. The county official said that, in two separate reports, well owners noticed problems with their well water approximately 2 weeks after nearby fracturing events. They reportedly believe hydraulic fracturing is responsible because the timing of the water loss coincides with the fracturing. Citizens know when gas producers fracture wells because they can see and hear the operation, which involves several trucks, tanks, manifolds, and mobile trailers. The county official noted that the formation being developed, the Fruitland Formation, is located approximately 2,400 feet below ground surface (bgs), and water wells are generally drilled from 100 feet to 200 feet bgs. He qualified his statements by indicating that wells do go dry for a variety of reasons.

- EPA contacted the Colorado Department of Health (CDH), which has primacy for the UIC Program under SDWA. An official with whom EPA spoke said CDH believes that water removal associated with coalbed methane development has caused problems in private water wells (Bodnar, 1999).

- EPA received one complaint from a citizen living in the Raton Basin in Trinidad, CO. She reported that water wells in her area have begun to decline in production and quality, often producing more and more gas. She believes the decline of water wells in her area is due to dewatering associated with coalbed methane production.

6.1.2 State Agency Follow-Up in the San Juan Basin

Colorado Oil and Gas Conservation

The Colorado Oil and Gas Conservation Commission (COGCC) is responsible for environmental issues related to oil and gas production in the state. The COGCC responds to every complaint called in to its office (Baldwin, 2000).

The COGCC staff believes that increased methane concentrations in water wells and buildings in some areas are partially due to old, improperly abandoned gas wells and older, deeper conventional gas wells in which the Fruitland Formation was not completely isolated. The state bases its opinions on monitoring and studies conducted in the San Juan Basin in response to complaints (see section 6.1.3). According to COGCC officials, the state's mitigation program focused on sealing old, improperly abandoned gas wells and appears to have reduced methane concentrations in approximately 27 percent of the water wells sampled. They believe that methane concentrations will decrease over time in other water wells where the source of the methane was gas wells. There are other areas of the San Juan Basin where the methane in water wells is produced by methanogenic bacteria in the aquifer. Methane concentrations in water wells in these areas probably will not decrease.

Officials cite studies that use stable carbon and hydrogen isotopes of methane and gas composition to differentiate between thermogenic methane from the Fruitland, Mesaverde, and Dakota Formations, and biogenic methane that is produced in shallower formations by naturally occurring methanogenic bacteria. By 1998, approximately two-thirds of the water wells for which gas isotopic analyses had been performed appeared to contain biogenic gas, while one-third appeared to contain thermogenic gas.

The state also noted that, in the interior basin, 1,100 feet of shale separates the Fruitland Formation and the shallow formations in which private wells are completed.

New Mexico Oil Conservation Division

EPA spoke with a District Geologist employed by the New Mexico Oil Conservation Division (NMOCD). He said that several years ago the office received many complaints that methane had contaminated water wells (Chavez, 2001). The state held water fairs at which anyone could have his or her water tested. In addition, the state initiated a program for cemented wells (some active, some abandoned) that prohibited open holes 100 feet above the casing string. The District Geologist indicated that the program seemed to solve the problem and that NMOCD has not received many subsequent complaints.

6.1.3 Major Studies That Have Been Conducted in the San Juan Basin

As noted previously, EPA reviewed a BLM study on the San Juan Basin to determine if it contained information pertaining to coalbed methane hydraulic fracturing and its impact, if any, on the quality of water in drinking water aquifers in the basin. EPA's review of this report focused on the two potential mechanisms by which hydraulic fracturing may affect the quality of USDWs: 1) direct injection of hydraulic fracturing fluids into a USDW or injection of fracturing fluids into a coal seam already in hydraulic communication with a USDW (e.g., through a natural fracture system), and 2) creation of a hydraulic connection between the coalbed formation and an adjacent USDW. The reports did not specifically address hydraulic fracturing, and only very little information indirectly addresses the question specific to this study: *Does the injection of hydraulic fracturing fluids into coalbed methane wells contaminate USDWs*?

The studies provided information on evidence that a hydraulic connection exists between coalbeds in the Fruitland Formation and overlying shallow aquifers and on possible conduits that may be the basis of the hydraulic connection. For example, the presence in a shallow aquifer of methane documented to be from the underlying Fruitland Formation is indirect evidence of a hydraulic connection, through some type of conduit, between the Fruitland Formation and shallower formations.

Evidence that a hydraulic connection exists between coalbeds and the shallow aquifer

The U.S. Department of the Interior's BLM (1999) provides a history of gas seeps and methane contamination of drinking water wells in the San Juan Basin. This section will review the evidence that indicates the existence of a hydraulic connection between the deep coalbeds and shallow USDWs.

Even prior to oil and gas drilling operations, shallow water wells in the San Juan Basin produced methane gas. Some wells in the Cedar Hill, NM, area of the basin were reported to have a strong sulfur odor. Some shallow water wells around the basin rim penetrated the Fruitland and Menefee coalbeds and produced methane (BLM, 1999). Thus, coalbed methane was the source of at least some of the observed methane contamination. Water from the Fruitland coalbed discharges in the western part of the basin and migrates upward across the Kirtland shale into the Animas and San Juan Rivers (Stone et al., 1983). In areas such as La Plata County, CO, along the northern and western rims of the basin, the methane presumably moves through natural fractures.

In the interior of the basin, gas seeps were observed in pastures in the Animas River Valley south of Durango near Bondad, CO, and Cedar Hill, NM, in the early to mid-1980s. Bubbles were also observed in the Animas River and in the tap water of rural properties in these areas. Methane was responsible for explosions in several pump houses. A landowner in New Mexico reported that gas was bubbling out of his alfalfa field and in the Animas River in 1985. Gas seeps were likely the cause of patches of dead grass growing in soils overlying the Mesaverde sandstone (BLM, 1999). Thus, conduits between methane-containing units and the surface were present both at the rim and in the interior of the basin.

After coalbed methane production began in the basin in the late 1980s, a local citizens' group voiced concerns that natural gas contamination of drinking water wells had increased in La Plata County. One study reported that 34 percent of the 205 domestic water wells tested in the county showed measurable concentrations of methane (BLM, 1999). This appears to indicate that there is a conduit for fluid to flow to the shallower USDW and its drinking water wells.

Shortly after the start of coalbed methane production in the basin, 11 coalbed methane wells were drilled within 2 miles of the Pine River Ranches Subdivision at the rim of the San Juan Basin. Nine to 35 feet of alluvium separate the surface from the Fruitland Formation coals in this area. A number of problems were reported following the onset of coalbed methane production. A man who complained that his well was contaminated with methane saw streams of gas bubbles in the nearby Los Pinos River. His report of methane contamination was confirmed by the San Juan Regional Authority (SJRA), which investigated reported contamination of this well and nearby wells. The other wells were also contaminated with methane. Two of the 4 residences near the 11 coalbed methane wells contained explosive levels of methane in crawl spaces (BLM, 1999). The methane sampled in the shallow wells and the bubbling river and the high concentrations of methane detected in residences suggest that coalbed methane was following some conduit from the Fruitland Formation to the surface or to shallow USDWs.

Evidence that methane in shallow drinking water wells originates in the Fruitland Formation (location of the coalbeds targeted by hydraulic fracturing)

Several lines of evidence show that methane detected in alluvial wells is not a result of sewage-derived methane contamination (BLM, 1999). Rather, the methane in the domestic wells studied originates either in conventional gas reservoirs such as the Dakota sandstone and the Lewis Shale or in the coals of the Fruitland Formation.

The composition of the gas in samples from shallow, private drinking water wells was analyzed to confirm the well owners' observations. The data obtained showed that the methane in approximately half of the samples appeared to have originated in the Fruitland Formation coalbeds and not from other possible sources such as septic tanks (BLM, 1999).

Similar sampling and analyses conducted in an additional study cited by BLM (1999) concluded that gas in a domestic well in alluvium overlying the Fruitland Formation had the same gas composition and carbon-13 isotope ratio as gas from a nearby gas well also in the Fruitland Formation. This study found that C13 isotopic signatures of individual near-surface gas samples correlated with production gas from discrete formations beneath the study area (BLM, 1999). In addition, an area resident's well contained 680 ppm TDS, primarily sodium bicarbonate. Fruitland-produced water has the same composition, although other domestic wells in the area do not. (TDS values tend to be in the 100 to 200 ppm in these other domestic wells.) Both the gas and the water analyses indicate that the shallow aquifer in the area (from which the methane-contaminated domestic wells draw drinking water) is in hydraulic communication with the deeper Fruitland Formation coalbeds.

Possible conduits for fluid movement from the coalbeds to the aquifer

Several studies have assessed possible natural or manmade conduits to account for the confirmed occurrence of methane in wells tapping the shallow aquifer that overlies the deeper coalbeds in the Fruitland Formation. Possible pathways enabling methane to move from a deep source to a shallow aquifer include natural fractures, hydraulically induced fractures, disposed of produced water from coalbed methane wells, and poorly constructed, sealed, or cemented conventional gas wells, coalbed methane wells, shallow drinking water wells, and cathodic protection wells installed to protect oil and gas pipelines from corrosion (BLM, 1999).

The history of documented gas seeps and methane occurrence in water wells indicates that natural fractures probably serve as conduits in parts of the basin where coal formations are near or at the surface and in the interior of the basin, where the coal formations are deeper. These conduits may enable hydraulic fracturing fluids to travel from targeted coalbeds to shallow aquifers. However, there is no unequivocal evidence that this fluid movement is occurring and, even given the presence of these possible conduits, other hydrogeologic conditions (such as certain pressure gradients, etc.) would be required for fluid movement from targeted coalbeds to shallow aquifers.

A study comparing soil-gas-methane concentrations adjacent to 352 gas-well casings and 192 groundwater wells found that the gas-well annuli (i.e., the spaces between the steel well casings and the walls of the drilled bore holes) were frequently the reason methane moved from the coalbeds to the near-surface environment (BLM, 1999). Thus, gas-well annuli are clearly one type of conduit for movement of methane from deeper sources up to overlying shallow aquifers.

The possibility of leaking gas wells acting as conduits through which methane flows from the Fruitland Formation to shallow aquifers was investigated by a joint Colorado Oil and Gas Conservation Commission/BLM study (BLM 1999). One hundred twenty water wells were tested for methane before and after nearby gas wells were “remediated” (better sealed). The study concluded that the relationship between gas well remediation and lower methane concentrations in drinking water was “complex” and may have been affected by the lingering presence of methane in drinking water after gas well remediation. More than half the water wells showed no significant changes in methane occurrence, a quarter showed lower methane levels, and one-tenth showed increased methane.

In summary, there appears to be evidence that methane seeps and methane in shallow geologic strata and water wells may occur because the methane moves through a variety of conduits. These conduits include natural fractures; poorly constructed, sealed, or cemented manmade wells used for various purposes. No reports provide direct information regarding hydraulic fracturing. Methane, fracturing fluid, and water with a naturally high TDS content could possibly move through any of these conduits. In some cases, improperly sealed gas wells have been remediated, resulting in decreased concentrations of methane in drinking water wells.

6.2 The Powder River Basin (Wyoming and Montana)

EPA spoke with several individuals familiar with coalbed methane activity in the Powder River Basin area who believe coalbed methane production is causing water quantity issues. These individuals have reported that dewatering during coalbed methane production resulted in loss of water from wells and in flooding problems on the surface. Many of the drinking water wells in the Powder River Basin are screened and completed in the same formation being dewatered for methane production. According to a consulting hydrogeologist, as much as 1 million gallons of water are pumped from each coalbed methane production well during its lifetime. Consequently, the aquifer has dropped 200 feet in some areas (Merchat, 1999). EPA has also learned that, as of 1999, oil and gas companies have drilled 2,000 wells in the Powder River Basin, and they reportedly plan to drill 15,000 in total (Merchat, 1999). However, deeper aquifers are available, and the oil and gas companies have drilled new water wells in those aquifers for private individuals.

Reports of incidents in the Powder River Basin are summarized below. However, hydraulic fracturing is performed infrequently in the Powder River Basin, and no one living in that area has reported problems relating to the process. Many of the complaints relate to water quantity issues, which are beyond the scope of this study.

EPA contacted the state and local offices of the Wyoming Health Department and the Water Quality Division of the Wyoming Department of Environmental Quality to determine if these departments had received complaints of water quality degradation due to coalbed methane production. Local authorities reported one complaint of black sediments in drinking water, but most concerns centered on water loss and flooding caused by large quantities of water discharged at the surface (Heath, 1999). There has been discussion among stakeholders regarding the handling of large volumes of water brought to the surface during coalbed methane production. Some individuals remain concerned about the consequences of dewatering aquifers, which include loss of the resource, effects on soil chemistry, flooding, and the potential for coalbed fires and subsidence.

EPA spoke with a consultant for the Powder River Basin Resource Council (PRBRC), a citizen’s group formed around environmental issues associated with coalbed methane production (Merchat, 1999). He stated that the biggest concern among people in the area is loss of water. However, some have had problems with increased methane content in their water. He said people reported methane in the water results in frothing and bubbles. The water is generally used for agricultural purposes and for drinking water. He said that each methane well produces millions of gallons of water in its lifetime. The discharge of water has created new ponds and swamps that are not naturally occurring in that region. The secondary effects from pumping water are subsidence and clinker beds (burning coal). When underground coal catches fire from lightning, it burns until it reaches groundwater. However, if there is no groundwater, the fire will continue to burn. The cost of manually extinguishing those fires is enormous. Furthermore, the burning of the coal can leave behind benzo(a)pyrene and other polycyclic aromatic hydrocarbons that are toxic and/or carcinogenic and could affect drinking water.

EPA Region 8 is participating in a study that addresses the environmental effects of all aspects of coalbed methane development and not just hydraulic fracturing.

6.3 The Black Warrior Basin (Alabama)

The *LEAF v. EPA* case arose from an alleged water quality degradation related to activities in Alabama. As discussed in Chapter 1, the Eleventh Circuit Court's 1997 decision in *LEAF v. EPA*, 118F.3d 1467, held that because hydraulic fracturing of coalbeds to produce methane is a form of underground injection, Alabama's EPA-approved UIC Program must effectively regulate this practice (11^{th} Cir, 1997). In response to the Court's decision, Alabama supplemented its rules governing the fracturing of wells to include additional requirements that govern the protection of USDWs during the hydraulic fracturing of coalbed methane. Summaries of reported incidents are presented in section 6.3.1 below.

6.3.1 Summary of Reported Incidents

- In the drinking water well case that precipitated *LEAF v. EPA*, an individual complained that drinking water from his well contained a milky white substance and had strong odors shortly after a fracturing event. He also reported that six months after the fracturing event his water had increasingly bad odors and occasionally contained black coal fines. The EPA Administrative Record regarding the Alabama Class II UIC Program contains other similar descriptions of well water problems.

- Another Alabama citizen reported to EPA problems with her drinking water well that began in 1989. In her letter, the citizen reported that her property was located near a coalbed methane gas well and that there was coal mining in the area. She wrote that she believes hydraulic fracturing of the coalbed methane well adversely affected her drinking water well, and coal resource exploitation in the area caused various, significant environmental damage. The individual believed that the hydraulic fracturing contributed to well contamination because, shortly after a fracturing event, her kitchen water contained globs of black, jelly-like grease and smelled of petroleum. She said her drinking water turned brown and contained slimy, floating particles. She reported that her neighbors also said their water smelled like petroleum.

  She included, as an attachment, a letter from the Alabama Oil and Gas Board (OGB) approving the use of proppants tagged with radioactive material. Their approval was based on the hydrogeology and the absence of water wells in the immediate area, the depths of the coal intervals to be fractured, well construction, and adherence to a program designed to monitor and contain radioactive material at the surface. Also attached was a letter from EPA Region 4 describing analytical results for samples the Agency collected from her drinking water well on June 26, 1990. The results indicated no purgeable and extractable organic compounds were detected. In addition, the letter said that a water/oil inter-phase detector was used to determine if petroleum products were floating in the well, and none was detected.

- An Alabama homeowner complained to the Natural Resources Defense Council that recovered hydraulic fracturing fluid from a nearby coalbed methane well installation was allowed to drain from the coalbed methane well site to a location near her home. She claimed that this fluid was initially obtained from an abandoned strip-mining quarry that had been used as a landfill for municipal and industrial waste. As this fluid drained from the fracturing site, the homeowner asserted, it killed all animal and plant life in its path. She further stated that shortly after this fracturing event and the associated runoff, her 110-foot deep drinking water well became contaminated with brown, slimy, petroleum-smelling fluid similar to the discharged fracturing fluid from the coalbed methane well site.

- In response to EPA's July 2001 call for information on water quality incidents (found in Water Docket W-01-09), an individual reported that her drinking water well had become filled with methane gas, causing it to hiss (66 FR 39396 (USEPA, 2001)); the tap water became cloudy, oily, and had a strong, unpleasant odor. In addition, the tap water left behind an oily film and contained fine particles. The drinking water well owner had her well tested by a private consultant, who confirmed the presence of methane.

  The Alabama OGB tested this drinking water well, but only looked for naturally occurring contaminants. EPA also sampled and tested this drinking water well, but not until 6 months after the event. No mention is made of the analytical results obtained from the drinking water well by these agencies.

6.3.2 State Agency Follow-Up (Alabama Oil and Gas Board)

LEAF v. EPA originated in Alabama. The water well that was reportedly contaminated as a result of hydraulic fracturing operations was sampled independently by the Alabama OGB, the Alabama Department of Environmental Management (ADEM), and EPA Region 4. Water analyses performed by these agencies indicated that the water well had not been contaminated as a result of the fracturing operation. The Alabama OGB reported to EPA that it investigates every complaint it receives, and it does not believe that hydraulic fracturing has affected water wells. Investigations include research into historical water quality data, some of which pre-dates coalbed methane activity. Such historical information is important because the coal-bearing Pottsville Formation often contains high concentrations of iron. Groundwater from this formation may contain iron-reducing bacteria, which can sometimes result in such water having an unpleasant taste or odor, or containing a white or red-brown, stringy, gelatinous material (Valkenburg and others, 1975, as cited by the Alabama OGB, 2002). In addition, sudden iron staining can occur in water with a history of good quality. Water well yield can also decline due to the presence of iron-reducing bacteria in high concentrations.

According to the Alabama OGB, one factor considered in each investigation is whether historical data are available on water quality in a particular area, including data that pre-date coalbed methane activity. Published reports and open-file data show that the quality of water in the coal-bearing Pottsville Formation can vary from good to very poor. Data collected from the 1950s through 1970s in localities throughout a large area where the Pottsville Formation has served as a source of water contain reports of water having "bad taste," "bad odors," "oily films or sheens," and waters causing "red stains" and "black stains" (Geological Survey of Alabama, 1930s to Present; Johnston, 1933, as cited by the Alabama OGB, 2002).

The Alabama OGB reported to EPA that it has investigated several complaints of methane gas in water wells. In each instance, the Alabama OGB determined that the water well problem was unrelated to coalbed methane extraction operations, which often were not occurring in the areas of reported water problems. Moreover, in some areas methane gas was reported in water wells many years before the advent of underground mining and the commercial development of this resource (Geological Survey of Alabama, 1930s to Present, as cited by the Alabama OGB, 2002). The problem of methane gas in water wells has generally occurred where water wells, usually less than 200 feet deep, penetrated gas-bearing coal strata, particularly following low rainfall years that caused a lowering of water tables. In these areas, there commonly had been a recent increase in the drilling of water wells and an acceleration in the rates of water withdrawal from the aquifer. When sufficient amounts of water are removed from these water wells, methane can begin to desorb from the coal seams and be produced.

Alabama's regulations have been approved by EPA for incorporation into Alabama's Class II UIC Program. Operators must provide written certification to the Board that the proposed fracturing operation will not occur in a USDW or that the fracturing fluids do not exceed the MCLs in 40 CFR §141 Subparts B and G. Fracturing is prohibited from ground surface to 299 feet bgs. For all fracture jobs performed between 300 feet and 749 feet bgs, the company must perform a reconnaissance of fresh-water supply wells within ¼ mile of the well to be fractured, submit a fracturing program to the OGB, and perform a cement bond log analysis. For fracturing events performed between 750 feet and 1,000 feet bgs, only a cement bond log is required. For fracturing events performed below 1,000 feet bgs, operators must submit to the Alabama OGB the depth to be fractured, well construction information, cementing specifications, and logs identifying overlying, impervious strata.

In Alabama, Rule 400-3-8-.03 states that coalbeds shall not be hydraulically fractured until written approval of the Oil and Gas Supervisor has been obtained. The Supervisor must be notified when an approved fracturing operation is to occur so that an agent of the Board may be present. In order to receive approval, operators must submit details of the proposed fracturing operation. The Board's staff evaluates each proposal for compliance to ensure USDW protection. Basic information that must be submitted with an operator's proposal to hydraulically fracture a well includes details on the depths of coalbeds to be fractured; construction of the well, including casing and cementing specifications; a geophysical log showing the type and thickness of impervious strata overlying the uppermost coalbed to be fractured; and, if the operation is to be performed in a USDW-bearing interval, a statement certifying that fracturing fluids will not exceed the MCLs of federally mandated primary drinking water regulations (40 CFR §141 Subparts B and G). In addition to the basic information, a fracturing program, a water well inventory within a ¼-mile radius, and a cement bond log must be provided with fracturing proposals in the depth interval 300 to 749 feet. Since water supply wells are generally shallower than coalbeds, Alabama's Rule 400-3-8-.03 was designed to increasingly strengthen the requirements for USDW protection with decreasing depths of proposed fracturing operations. Furthermore, the fracturing of coalbeds shallower than 300 feet is prohibited.

6.4 The Central Appalachian Basin (Virginia and West Virginia)

EPA became aware of several complaints relating to the effects of coalbed methane production on sources of drinking water in the southwestern portion of Virginia through correspondence initiated by citizens. Information about water quality incidents was gathered through meetings and telephone conversations with members of the Virginia Division of Oil and Gas within the Department of Mines, Minerals and Energy (VDMME); local health officials; and representatives of a county citizen's group. In total, VDMME provided EPA with over 70 "Complaint Detail Reports" (registered between 1990 and 2001) that related to drinking water source impacts by coalbed methane development.

Although the majority of the incidents outlined in the complaints pertain to water-loss issues, approximately one-quarter relate to water quality. Virginians living near coalbed methane production areas reported private well and spring water contamination evidenced by oily films, soaps, iron oxide precipitates, black sediments, methane gas, and bad odor and taste. Reports of water loss in the well ranged from noticeably reduced supply rates to total loss of water from domestic drinking water wells. Summaries of reported incidents and state follow-up are discussed in sections 6.4.1 and 6.4.2, respectively.

6.4.1 Summary of Virginia Incidents

- The state received complaints of soap bubbles flowing from residential household fixtures. VDMME attributes soap coming out of water faucets to the drilling process associated with both conventional wells and coalbed methane wells. Soaps are used to extract drilling cuttings from the borehole because the foam expands, rises, and, as it rises, carries the cuttings to the surface (Wilson, 2001). These soaps may migrate from the borehole into the drinking water zone that supplies private wells during drilling of the shallow portion of the hole and before the required groundwater casing is cemented in place. In the few occurrences of soap contamination, water was provided until the soap was completely purged from the contributing area surrounding their water well.

- In early August 2001, EPA met with approximately 15 to 20 residents of Buchanan and Dickenson Counties in Virginia. Coalbed methane production activity is steadily increasing in the area surrounding Buchanan County since the coal reserves in this area have proven to be extremely profitable sources for coalbed methane in recent years (Wilson, 2001). The subjects of the citizen complaints were very similar to those logged in the VDMME complaint reports. Residents described the presence of black sediments, iron precipitates, soaps, diesel fuel smells, and increased methane gas in drinking water from their wells. One resident brought a water sample collected from her drinking water well. The water was translucent with a dark gray color and with dark black suspended sediment. Several other citizens reported drinking water supplies diminishing or drying up entirely. One resident of Buchanan County said that he had an ample water supply from his drinking well for over 54 years, until shortly after coalbed methane wells were installed on his property. He reported that within 60 days of the coalbed methane well installations, his 276-foot deep drinking water supply well, which used to produce over 20 gallons per minute of potable flow, dried up. The resident mentioned that over 380 homes in the region do not have potable water as a result of coalbed methane mining activities.

  Most of the residents said that their complaints to the state usually resulted in investigations without resolution. Some residents mentioned that the gas companies were providing them with potable water to compensate for the contamination or loss of their drinking water wells. However, the residents said that this was not adequate compensation for the impacts to, or loss of, their private drinking water supplies.

- EPA was able to record numerous complaints through telephone conversations and e-mails with Virginia residents, who reported that they believed their drinking water wells had been affected by coalbed methane industry activities. All the logged complaints were from Buchanan and

Dickenson Counties. Complaints include water loss, soapy water, diesel odors, iron and sulfur in wells, rashes from showering, gassy taste, and murky water. One report discusses a miner who was burned by a fluid, possibly hydrochloric acid used in hydraulic fracturing, that infiltrated a mineshaft. Another report describes the contamination of a stream and the resulting fish kills caused by the runoff from drilling fluids. One complainant explained that several thousand wells had "gone dry, overnight." According to the individuals EPA spoke with, compensation to homeowners for these impacts is in the form of money, newly drilled wells to replace dry or contaminated wells or temporary provision of potable water, which is supplied "until things clear out."

6.4.2 State Agency Follow-Up (VDMME)

VDMME, Division of Gas and Oil, is responsible for responding to environmental issues associated with oil and gas development; it investigates every water problem reported. Responses may include an interview with the citizen reporting the problem, a site visit, water well testing, or a review of the physical aspects of the water well and surrounding activities. According to Robert Wilson of VDMME, his agency tests for contaminants that may be introduced by drilling such as chlorides, oil and grease, and volatile organics. The results of those analyses are compared to baseline values. VDMME witnesses surface casing and plugging jobs as part of its oversight duties. VDMME reviews information from drilling and completion reports to assist with investigations into complaints.

Based on investigations of the more than 70 complaints received, VDMME believes that coalbed methane production has not affected private drinking water wells. VDMME recognizes soap migrating into drinking water wells, but considers this only a transient problem. While a number of complaints report a noticeable reduction in or a total loss of drinking water supply, in almost all cases, the state investigator determined that the water loss was not likely to be caused by local hydraulic fracturing events or coalbed methane production activity because:

- The distance from the private well to the nearest coalbed methane well is too far (1,500 feet or more) to have any impact.

- There is no hydrologic connection between the water contribution zones of the private and coalbed methane wells; therefore, it is physically impossible for coalbed methane wells to affect private drinking water wells.

- The well was constructed according to VDMME regulatory guidelines; therefore, a sufficient buffer exists between the private well and the coalbed methane well.

- The existing supply was reduced because of recent drought conditions in the region.

- The complainant experienced mechanical difficulty with his or her pumping system, which led to a reduction in pumped water; however, the supply was not affected.

According to VDMME, these citizen complaints refer to incidents that can occur during the drilling of any type of well, not just coalbed methane. The few incidents of this kind were equally divided between conventional wells and coalbed wells (VDMME, 2002).

6.5 Summary

In this chapter, EPA has presented information (in addition to technical, conceptual, or theoretical information presented previously) on personal experiences with regard to coalbed methane activities and their potential (or perceived potential) to impact drinking water wells. These personal accounts of potential incidences in four producing coal basins across the United States do not present scientific findings. However, the body of reported problems considered collectively suggest that water quality (and quantity) problems might be associated with some of the production activities common to coalbed methane extraction. These activities include surface discharge of fracturing and production fluids, aquifer/formation dewatering, water withdrawal from production wells, methane migration through conduits created by drilling and fracturing practices, or any combination of these. Other potential sources of drinking water problems include various aspects of resource development, naturally occurring conditions, population growth and historical practices.

In several of the coalbed methane investigation areas, local agencies concluded that hydraulic fracturing could not affect drinking water wells. Generally, these conclusions were based on there being a significant horizontal and/or vertical distance between the coalbed methane production wells and the drinking water wells.

Chapter 7
Conclusions and Recommendations

Under SDWA, EPA's UIC Program is responsible for ensuring that fluids injected into the ground do not endanger USDWs. The goal of the Phase I study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into coalbed methane wells, and to determine, based on these findings, whether further study is warranted.

EPA's approach for evaluating the potential for contamination of USDWs was an extensive information collection and review of empirical and theoretical data. EPA reviewed water quality incidents potentially associated with hydraulic fracturing and evaluated the theoretical potential for hydraulic fracturing to affect the quality of USDWs through one of two mechanisms:

1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

7.1 Reported Water Quality Incidents

Citizens from Wyoming, Montana, Alabama, Virginia, Colorado, and New Mexico contacted EPA because they were concerned that their water wells were affected by coalbed methane production. The major geographic areas where citizens reported experiencing problems due to coalbed methane development are concentrated in the coal basins with the most coalbed methane activities – the San Juan, Black Warrior, Central Appalachian, and Powder River Basins. This study was initiated, partly, in response to those citizens' concerns. EPA followed-up on letters and telephone calls from citizens and resulting leads to understand specific complaints and citizens' concerns.

EPA published a *Federal Register* notice (66 FR 39396 (USEPA, 2001) requesting information on water quality incidents believed to be associated with hydraulic fracturing of coalbed methane wells. EPA notified over 500 local and/or county agencies in areas with potential coalbed methane production activity to make them aware of the *Federal Register* notice requesting information on coalbed methane-related complaints. The Agency received no information on complaints from these officials.

EPA reviewed responses and follow-up actions conducted by state agencies to address groundwater complaints involving coalbed methane. Hydraulic fracturing is not widely practiced in the Powder River Basin (which includes Wyoming and Montana) and concerned citizens from that area reported surface water and groundwater quantity problems rather than specifying hydraulic fracturing as a problem. Studies of groundwater quality in the San Juan Basin (which includes parts of Colorado and New Mexico) do not address hydraulic fracturing directly. However, problems with groundwater quantity and quality in Colorado may have plausible explanations other than hydraulic fracturing activities. For example, natural fractures, and poorly constructed, sealed, or cemented wells used for various purposes, may provide conduits for methane to move into shallow geologic strata and water wells, or even to surface water (BLM, 1999). The New Mexico Oil Conservation Division reported that citizens began reporting increased levels of methane in their water wells after coalbed methane development began in the San Juan Basin. New Mexico initiated a plugging and abandonment program to seal old, improperly abandoned production wells, which appears to have mitigated the problem (Chavez, 2001).

EPA also obtained individual incident reports from Virginia. None of Virginia's follow-up investigations provided evidence that hydraulic fracturing of coalbed methane wells had caused drinking water well problems. Incidents in Alabama were investigated by the Alabama Oil and Gas Board, the Alabama Department of Environmental Management, and EPA Region IV. Samples from drinking water wells did not test positive for constituents found in fracturing fluids. After reviewing all the available data and incident reports, EPA sees no conclusive evidence that water quality degradation in USDWs is a direct result of injection of hydraulic fracturing fluids into coalbed methane wells and subsequent underground movement of these fluids.

7.2 Fluid Injection Directly into USDWs or into Coal Seams Already In Hydraulic Communication with USDWs

To determine if USDWs are threatened by the direct injection of fracturing fluids into a USDW, EPA: 1) reviewed information on 11 major U.S. coal basins mined for coalbed methane to determine if coal seams lie within USDWs, and 2) identified components of fracturing fluids. EPA also used the information on the 11 major U.S. coal basins as well as information collected on water quality incidents potentially associated with hydraulic fracturing to determine if coal seams are already in hydraulic communication with USDWs. Hydraulic fracturing has been, or is being, performed in every basin reviewed. As summarized in Table 5-1 in Chapter 5, evidence suggests that coalbeds in 10 of the 11 major coal basins in the United States are located at least partially within USDWs. The coalbeds in the Piceance Basin in Colorado, however, are several thousand feet below USDWs, and are unlikely to be in hydraulic communication with USDWs.

Hydraulic fracturing fluids injected into coalbed methane wells consist primarily of water, or inert nontoxic gases, and/or nitrogen foam and guar (a naturally occurring substance derived from plants). According to information gathered from MSDSs, on-site reconnaissance of fracturing jobs, and interviews with service company employees, some hydraulic fracturing fluids may contain constituents of potential concern. Table 4.1 in Chapter 4 lists examples of chemicals found in hydraulic fracturing fluids according to the MSDSs. Constituents of potential concern include the following substances either alone or in combination: bactericides, acids, diesel fuel, solvents, and/or alcohols. Although the largest portion of fracturing fluid constituents is nontoxic (>95% by volume), direct fluid injection into USDWs of some potentially toxic chemicals does take place.

For example, potentially hazardous chemicals are introduced into USDWs when diesel fuel is used in fracturing fluids in operations targeting coal seams that lie within USDWs. Diesel fuel contains constituents of potential concern regulated under SDWA – benzene, toluene, ethylbenzene, and xylenes (i.e., BTEX compounds). However, the threat posed to USDWs by introduction of these chemicals is reduced significantly by coalbed methane production's dependence on the removal of large quantities of groundwater (and injected fracturing fluids) soon after a well has been hydraulically fractured. EPA believes that this groundwater production, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation, minimize the possibility that chemicals included in the fracturing fluids would adversely affect USDWs.

Because of the potential for diesel fuel to be introduced into USDWs, EPA requested, and the three major service companies agreed, to eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for coalbed methane production. Industry representatives estimate that these three companies perform approximately 95 percent of the hydraulic fracturing projects in the United States. These companies signed an MOA on December 15, 2003 and have indicated to EPA that they no longer use diesel fuel as a hydraulic fracturing fluid additive when injecting into USDWs for coalbed methane production (USEPA, 2003).

7.3 Breach of Confining Layer

The second mechanism by which hydraulic fracturing may affect the quality of USDWs is fracturing through a hydrologic confining layer, and creation of a hydraulic communication between a coal seam and an overlying USDW. If sufficiently thick and relatively unfractured shale is present, however, it may act as a barrier not only to fracture height growth, but also to fluid movement.

A hydraulic fracture will propagate perpendicularly to the minimum principal stress. In some shallow formations, the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. In deeper reservoirs, the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical. In general, horizontal fractures are most likely to exist at shallow depths (less than 1,000 feet) (Nielsen and Hansen, 1987 as cited in Appendix A: DOE, Hydraulic Fracturing). Most coal seams currently used for methane production are relatively shallow compared to conventional oil production wells, but still lie deeper than 1,000 feet.

Hydraulic fracturing may have increased or have the potential to increase the communication between coal seams and adjacent formations in some instances. For example, in the Raton Basin, some fracturing treatments resulted in higher than expected withdrawal rates for production water. Those increases, according to literature published by the Colorado Geologic Survey, may be due to well stimulations creating a connection between targeted coal seams and an adjacent sandstone aquifer (Hemborg, 1998). In the Powder River Basin, concerns over the creation of such a hydraulic connection are cited as one reason why hydraulic fracturing of coalbed methane reservoirs is not widely practiced in the region. Some studies that allow direct observation of fractures (i.e., mined-through studies) also provided evidence that fractures move through interbedded layers, sometimes taking a stair-step pathway through complex fracture systems, and sometimes enter or propagate through geologic strata above the coal (i.e., roof rock) (Diamond, 1987a and b; Diamond and Oyler, 1987; Jeffrey et al., 1993).

Fracture height is important to the issue of whether or not hydraulic fracturing fluids can affect USDWs because shorter fractures are less likely to extend into a USDW or connect with natural fracture systems that may transport fluids to a USDW. The extent of a fracture is controlled by the characteristics of the geologic formation (including the presence of natural fractures), the volume and types of fracturing fluid used, the pumping pressure, and the depth at which the fracturing is being performed. Deep vertical fractures can propagate vertically to shallower depths and develop a horizontal component (Nielsen and Hansen, 1987, as cited in Appendix A: DOE, Hydraulic Fracturing). In these "T-fractures," the presence of coal fines or a zone of stress contrast may cause the fracture to "turn" and develop horizontally, sometimes at the contact of the coalbed and an overlying formation (Jones et al., 1987b; Morales et al., 1990).

The low permeability of relatively unfractured shale may help to protect USDWs from being affected by hydraulic fracturing fluids in some basins. At some sites, shale may act not only as a hydraulic barrier, but also as a barrier to fracture height growth. Shale's ability to act as a barrier to fracture height growth is due primarily to the stress contrast between the coalbed and the higher-stress shale (see Appendix A)

Another factor controlling fracture height can be the highly cleated nature of some coalbeds. In some cases, highly cleated coal seams will prevent fractures from growing vertically. When the fracture fluid enters the coal seam, it is contained within the coal seam's dense system of cleats and the growth of the hydraulic fracture will be limited to the coal seam (see Appendix A).

Mined-through studies indicate many hydraulic fractures that penetrate into, or sometimes through, formations overlying coalbeds can be attributed to the existence of pre-existing natural fractures. However, given the concentrations and flowback of injected fluids, and the mitigating effects of fate and transport processes, EPA does not believe that possible hydraulic connections under these circumstances represent a significant potential threat to USDWs.

7.4 Conclusions

Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into coalbed methane wells poses little or no threat to USDWs and does not justify additional study at this time. This decision is consistent with the process outlined in the April, 2001 Final Study Design, in which EPA indicated that it would determine whether further investigation was needed after analyzing the Phase I information. Specifically, EPA determined that it would not continue into Phase II of the study if the investigation found that no hazardous constituents were used in fracturing fluids, hydraulic fracturing did not increase the hydraulic connection between previously isolated formations, *and* reported incidents of water quality degradation were attributed to other, more plausible causes.

Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is reduced significantly by groundwater production and injected fluid recovery, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation. Additionally, EPA has reached an agreement with the major service companies to voluntarily eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for coalbed methane production.

Often, a high stress contrast between adjacent geologic strata results in a barrier to fracture propagation. This may occur in those coal zones where there is a geologic contact between a coalbed and a thick, higher-stress shale that is not highly fractured. Some studies that allow direct observation of fractures (i.e., mined-through studies) indicate many fractures that penetrate into, or sometimes through, formations overlying coalbeds can be attributed to the existence of pre-existing natural fractures. However, and as noted above, given the concentrations and flowback of injected fluids, and the mitigating effects of dilution and dispersion, fluid entrapment, and potentially biodegradation, EPA does not believe that possible hydraulic connections under these circumstances represent a significant potential threat to USDWs.

EPA also reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing and found no confirmed cases that are linked to fracturing fluid injection into coalbed methane wells or subsequent underground movement of fracturing fluids. Although thousands of coalbed methane wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into coalbed methane wells.

Public Comment and Response Summary for the Study on the Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water

FINAL

Office of Water
Office of Ground Water and Drinking Water (4606M)
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FINAL

June 2004

United States Environmental Protection Agency
Office of Water
Office of Ground Water and Drinking Water
Drinking Water Protection Division
Prevention Branch
1200 Pennsylvania Avenue, NW (4606M)
Washington, DC 20460

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LIST OF ACRONYMS AND ABBREVIATIONS

BLM	Bureau of Land Management
BTEX	Benzene, Toluene, Ethylbenzene, and Xylenes
CBM	Coalbed Methane
CCL	Contaminant Candidate List
CFR	Code of Federal Regulations
COGCC	Colorado Oil and Gas Conservation Commission
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency or Agency
FR	Federal Register
GWPC	Ground Water Protection Council
MCL	Maximum Contaminant Level
MOA	Memorandum of Agreement
MSDS	Material Safety Data Sheet
MTBE	Methyl Tert Butyl Ether
NAS	National Academy of Science
PWS	Public Water System
RfD	Reference Dose
SDWA	Safe Drinking Water Act
UCMR	Unregulated Contaminant Monitoring Regulation
UIC	Underground Injection Control Program
USDW	Underground Source of Drinking Water

Public Comment and Response Summary for the Study on the Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Water

I. INTRODUCTION

The United States Environmental Protection Agency's (EPA's) Office of Ground Water and Drinking Water completed its Phase I study, which assesses the potential for contamination of underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids into coalbed methane (CBM) wells. EPA (or the Agency) began collecting information on hydraulic fracturing in the fall of 2000. Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time.

The draft report, titled, "Draft Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs" (hereafter referred to as the draft report), was made available for public comment by an announcement in the *Federal Register* on August 28, 2002.[1] The 60-day public comment period officially ended on October 28, 2002.

The Agency received and reviewed comments from 105 commenters. Several of these were signed by multiple parties (which were counted as one commenter), including a few coalitions of environmental organizations. The commenters include private citizens; environmental and citizen groups; government agencies at the local, state, and national levels; oil and gas companies; trade associations; and four other commenters that do not fit these categories. Table 1 below provides a listing of these commenters.

[1] US Environmental Protection Agency. 2002. Underground Injection Control (UIC) Program; Hydraulic Fracturing of Coalbed Methane (CBM) Wells Report--Notice. *Federal Register*. Vol. 67, No. 167. p. 55249, August 28, 2002.

TABLE 1: LIST OF PUBLIC COMMENTERS		
Docket ID[1]	**Edocket ID (OW-2001-0002)[2]**	**Organization (State)**
Environmental/Citizens Groups		
II-D1.014	045	Bull Mountain Landowners Association (MT)
II-D1.025	055	Land and Water Fund of the Rockies (CO)
II-D1.040	068	Dickenson County Citizens Committee (VA)
II-D1.046	074	Western Organization of Resource Councils and Coalition of 11 Other Environmental/Citizens Groups (DC)
II-D1.055	043	Coalition of 28 Environmental/Citizens Groups (varies)
II-D1.060	085	Oil & Gas Accountability Project and Coalition of 34 Other Environmental/Citizens Groups (CO)
II-D1.072	100	National Resources Defense Council (DC)
II-D1.101	139	San Juan Citizen's Alliance (CO)
II-D1.076; II-D2.001; II-D2.002	106 - 109	Kentucky Resources Council, Inc. (KY)
Private Citizens		
II-D1.004	033	Citizen (AK)
II-D1.050	031	Citizen (AL)
II-D1.012; II-D1.017	041; 048	Citizen (CA - 2)
II-D1.002; II-D1.003; II-D1.006; II-D1.008; II-D1.009; II-D1.011; II-D1.016; II-D1.018; II-D1.022; II-D1.023; II-D1.024; II-D1.026; II-D1.030; II-D1.031; II-D1.032; II-D1.034; II-D1.037; II-D1.038; II-D1.043; II-D1.044; II-D1.049; II-D1.058; II-D1.065; II-D1.067; II-D1.081; II-D1.083; II-D1.084; II-D1.085; II-D1.086; II-D1.087; II-D1.088; II-D1.089; II-D1.093; II-D1.095; II-D1.097; II-D1.099; II-D1.100; II-D1.102; II-D2.008	110; 032; 035; 037; 038; 040; 047; 049; 052; 053; 054; 056; 060; 061; 112; 128; 065; 066; 071; 072; 075; 083; 092; 094; 118; 120; 121; 122; 123; 124; 125; 126; 131; 133; 135; 137; 138; 140; 148	Citizen (CO - 39)
II-D1.015; II-D1.027; II-D1.029; II-D1.041; II-D1.098	046; 057; 059; 069; 136	Citizen (FL - 5)
II-D1.007	036	Citizen (KS)
II-D1.039; II-D1.048; II-D2.007	067; 030; 142	Citizen (MT - 3)
II-D1.005; II-D1.033; II-D1.051	034; 062; 076	Citizen (NM - 3)
II-D1.013; II-D1.019	044; 050	Citizen (NY - 2)
II-D1.042	070	Citizen (UT)
II-D1.028; II-D1.094	058; 132	Citizen (state unknown - 2)
State/Local/Federal Agencies		
II-D1.010	039	Sandia National Laboratories (NM)
II-D1.045	073	San Miguel County Board of Commissioners (CA)
II-D1.047	029	Alabama Oil and Gas Board (AL)
II-D1.057	082	State of New Mexico Energy, Minerals and Natural Resources Department (NM)
II-D1.059	084	Virginia Division of Gas and Oil (VA)
II-D1.061	086	Colorado Geological Survey (CO)
II-D1.062	087; 088	Michigan Department of Environmental Quality (MI)
II-D1.063	089	Pennsylvania Department of Conservation and Natural Resources (PA)
II-D1.064	090	State of Utah Department of Natural Resources, Division of Oil, Gas and Mining (UT)
II-D1.066	093	Alaska Oil and Gas Conservation Commission (AK)

TABLE 1: LIST OF PUBLIC COMMENTERS		
Docket ID[1]	Edocket ID (OW-2001-0002)[2]	Organization (State)
II-D1.068	095	State of South Dakota (SD)
II-D1.069	096	Ohio Department of Natural Resources (OH)
II-D1.073	101; 102	Conservation Division of the Kansas Corporation Commission (KS)
II-D1.079	116	State of Louisiana, Department of Natural Resources (LA)
II-D1.080	117	Colorado Oil & Gas Conservation Commission (CO)
II-D1.082	119	State of Missouri Department of Natural Resources, Geological Survey & Resource Assessment Division (MO)
II-D1.092	130	Indiana Department of Natural Resources, Division of Oil and Gas (IN)
II-D1.096	134	State of Oklahoma, Office of the Secretary of Energy (OK)
II-D1.103	147	Delta County Commissioners (CO)
II-D2.006	141	Office of Fossil Energy, Department of Energy (DC)
II-D2.009	149	Ohio Department of Natural Resources, Division of Mineral Resources Management (OH)
Oil and Gas Companies		
II-D1.070	097	Halliburton Energy Services (TX)
II-D1.075	105	Chevron Texaco North American Upstream (TX)
II-D1.090	127	Shell Exploration & Production Company (TX)
Trade Associations		
II-D1.035	113	Domestic Petroleum Council (DC)
II-D1.036	064	Independent Petroleum Association (DC)
II-D1.052	077	Interstate Oil and Gas Compact Commission (OK)
II-D1.053	080	Independent Oil & Gas Association of West Virginia (WV)
II-D1.054	042	Coalbed Methane Association of Alabama (AL)
II-D1.056	081	Oklahoma Independent Petroleum Association (OK)
II-D1.071	099	Ground Water Protection Council (OK)
II-D1.074	104	American Petroleum Institute (DC)
Other		
II-D1.020	051	Pace Law School (NY)
II-D1.021	111	University of Montana, Montana Bureau of Mines and Geology, Montana Tech (MT)
II-D1.077	114	Steven Harper, Attorney at Law (CO)
II-D1.078	129	Hansen Environmental Consultants (WA)

[1] Docket Identification numbers are assigned by the Water Docket in order to track each public comment with a unique identification number. Note that if a comment has a prefix of "II-D2," it indicates that the comment was received after the October 28, 2002 comment deadline. Comments with the following docket logs were updates, repeats, or clarifications of other comments: II-D1.91; II-D2.03; II-D2.04; and II-D2.05.

[2] An electronic version of each public comment is available through EPA's electronic public docket and comment system, EPA Dockets at http://www.epa.gov/edocket/. Each comment begins with the prefix "OW-2001-0002-". Edocket numbers were assigned to comment materials, as well as other relevant background documents in the order they were posted to the edocket Web site.

The remainder of this document contains summaries of the major public comments and EPA's responses related to the Agency's August 2002 report. The document is divided into seven other major sections as follows:

- **Section II: Scope of the Study** discusses public comments and EPA's responses on areas not included in the study, the literature used for the review, the number of coal basins included in the study, citizen complaints regarding water well contamination, and the peer review panel who reviewed the initial draft of the report.

- **Section III: Fracturing Fluids** describes public comments and EPA's responses related to the components of fracturing fluids, EPA's comparison of the concentration of fracturing fluid constituents to maximum contaminant levels (MCLs), EPA's estimates for the concentrations of fracturing fluid chemicals at the point-of-injection and the edge of the fracture zone, the amount of fracturing fluids that is recovered from CBM reservoirs, the amount of fracturing fluids used in hydraulic fracturing procedures, and the movement of "stranded" fluids in the coalbed formations.

- **Section IV: Fracture Behavior and Practices** discusses comments raised and EPA's responses to these comments regarding fracture growth, multiple fracturing of the same well, the relationship of drinking water wells to hydraulic fracturing activities, and differences in state geology.

- **Section V: Regulation of Hydraulic Fracturing Practices** describes comments and the Agency's responses regarding the states' authority over hydraulic fracturing practices, and the regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA).

- **Section VI: Language Used in the Report** summarizes specific comments and the Agency's responses related to the use of the term "USDW" in the report, use of scientific terms, and the tone of the language in the report.

- **Section VII: Chapter-Specific Comments** describes comments and the Agency's response regarding the glossary, executive summary, and Chapters 1 through 7 that were not already covered under Sections II through VI of this document.

- **Section VIII: Basin Descriptions** describes comments that pertain to the basin-specific descriptions in Attachments 1 through 11 of the report and EPA's response to these comments. The comments and responses in Section VIII do not include comments that were already discussed in Sections II through VII of this document.

II. SCOPE OF THE STUDY

A. Areas Not Included in the Review

1. Focus of the Report

Summary of Comments: One commenter indicated that the report should have focused on the possible impacts to human health instead of the hydraulic fracturing process. This commenter added that Chapter 4 of the report should have focused on dose-response curves and not on the properties of hydraulic fracturing fluids. The commenter also stated that EPA should have been able to conduct this analysis because the Agency should have access to research conducted on the toxicity of all constituents used in CBM production.

Another commenter stated that the study did not address the uncertainty in the risk assessment due to omissions and errors in the data used for the study. This commenter indicated that some of the reasons for these omissions and errors could be inadequate reporting by private well owners and counties, inadequate testing, and inadequate enforcement which would result in an underassessment of risk. This commenter also indicated that the report does not address risk resulting from deviations and failures in drilling, fracturing, and monitoring practices, especially for newer wells, or sufficiently address the testing error for volatile chemicals used in hydraulic fracturing.

EPA Response: The Phase I study was not intended to be a risk assessment, but rather, to be a fact-finding effort based primarily on existing literature to assess the potential threat to USDWs from the injection of hydraulic fracturing fluids into CBM wells and to determine based on these findings, whether additional study is warranted. The study is tightly focused on hydraulic fracturing of CBM wells and does not include other aspects of drilling or CBM production. EPA reviewed water quality incidents potentially associated with hydraulic fracturing, as well as evaluated the theoretical potential for hydraulic fracturing to affect USDWs. EPA researched over 200 peer-reviewed publications, interviewed approximately 50 employees from industry and state or local government agencies, and communicated with approximately 40 citizens and groups who are concerned that CBM production affected their drinking water wells.

For the purposes of this study, EPA assessed USDWs impacts by the presence or absence of documented drinking water well contamination cases caused by CBM hydraulic fracturing, clear and immediate contamination threats to drinking water wells from CBM hydraulic fracturing, and the potential for CBM hydraulic fracturing to result in USDW contamination based on two possible mechanisms described below.

1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

EPA's report includes a discussion of the types of fracturing fluids and additives, and fluid volumes that may be used in hydraulic fracturing operations. This discussion is intended to provide further background on the hydraulic fracturing process. In addition, the study provides a review of the fate and transport of injected fluids in the subsurface in order to determine whether a detailed risk assessment is warranted.

2. Monitoring

Summary of Comments: Several commenters questioned how EPA could decide whether hydraulic fracturing poses a risk to USDWs without collecting or reviewing monitoring data. Several commenters wanted EPA to proceed to Phase II of the study and to install monitoring wells in areas where hydraulic fracturing of CBM wells was occurring. One commenter recommended that, at a minimum, EPA identify whether any type of monitoring has been conducted by consulting firms, local or state agencies, or members of the academic community, and if this monitoring exists, to include the results in the report.

Another commenter recommended that EPA, in cooperation with the National Academy of Science (NAS), conduct unannounced inspections of hydraulic fracturing projects in order to collect samples of hydraulic fracturing fluids, and observe and measure the total volume of injected hydraulic fracturing fluid. This commenter also recommended that EPA establish reference doses (RfDs) and MCLs for all chemicals currently used in hydraulic fracturing fluids in significant volumes.

EPA Response: EPA has researched and reviewed a variety of monitoring information that may be related to the issue of possible conduits for fracturing fluid transport into USDWs. These data are discussed in Chapter 6 of the report. For example, EPA reviewed a 1999 Bureau of Land Management (BLM) report which focused on monitoring and data interpretation of methane concentrations in groundwater in the San Juan Basin area. EPA reviewed this report to determine if it contained information pertaining to hydraulic fracturing of CBM and its impacts, if any, to the quality of water in drinking water aquifers in this basin.

Chapter 6 of the report provides a detailed discussion of citizen complaints and state responses to their concerns. Complaints were responded to by various state agencies, and many of those responses included testing of water for contaminants. For example, the Virginia Department of Mines, Minerals and Energy is responsible for: responding to environmental issues associated with oil and gas development (including CBM); investigating all reported water problems; and testing water samples for contaminants that may be introduced by drilling (such as chlorides, oil and grease, and volatile organics).

EPA disagrees that monitoring data is needed to determine whether a Phase II study is warranted. As discussed in the previous response, EPA conducted an extensive literature review, conducted numerous interviews, reviewed water quality incidents potentially associated with hydraulic fracturing, and evaluated the theoretical potential for hydraulic fracturing to affect USDWs. EPA's decision that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time is consistent with the process outlined in the April, 2001 Final Study Design. In its final study design, EPA indicated that the Agency would make a determination regarding whether further investigation was needed after analyzing the Phase I information.

EPA has recently taken a specific and important measure to address one of the primary concerns regarding hydraulic fracturing fluid – the use of diesel fuel. During EPA's research, the Agency realized that diesel is sometimes used a component of fracturing fluids and is of specific concern because it contains BTEX compounds (benzene, toluene, ethylbenzene, and xylenes) for which MCLs have been established under SDWA. Because of the potential problem diesel can cause, EPA requested its removal from hydraulic fracturing fluids. On December 15, 2003, EPA entered into a Memorandum of Agreement (MOA) with three major service companies – BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation – to voluntarily eliminate diesel fuel from hydraulic fracturing fluids that are injected directly into USDWs for CBM production. If necessary, these companies will select replacements that will not cause hydraulic fracturing fluids to endanger USDWs. Industry representatives estimate that these three companies conduct an estimated 95 percent of the hydraulic fracturing projects in the United States. These three have indicated to EPA that they no longer use diesel fuel as a hydraulic fracturing fluid additive when injecting into USDWs.

EPA, through its Underground Injection Control (UIC) Program, as authorized under SDWA Part C, Sections 1421-1426), is responsible for ensuring that fluids injected into the ground do not endanger USDWs or cause a public water system (PWS) to violate its drinking water standards due to the contamination of a USDW by these injected fluids. Most states have primary enforcement authority (primacy) for implementation of the UIC Program, and thus have the authority under SDWA to place controls on any injection activities that may threaten USDWs. 40 CFR 145.12, Requirements for Compliance Evaluation Programs, requires that authorized states have programs for periodic inspections of injection operations. States may also have additional authorities by which they can regulate hydraulic fracturing. While surprise inspections are not specifically mandated, state programs have a responsibility to conduct inspections, as necessary, to determine compliance with permit conditions, and to verify the accuracy of monitoring data and other information. EPA requires that all UIC inspectors be certified in, and that inspectors be knowledgeable about, proper operation of injection facilities, protection of USDWs, and SDWA requirements.

Regarding the establishment of RfDs and MCLs for all hydraulic fracturing fluid chemicals used in significant volumes, EPA follows an established procedure for identifying the contaminants for which these standards will be set. The Contaminant Candidate List (CCL) and the Unregulated Contaminant Monitoring Regulation (UCMR) are the primary review mechanisms by which EPA identifies drinking water contaminants which pose the most urgent threat to public health. The CCL process uses the best available information on contaminants of concern and emerging contaminants to prioritize according to potential public health threat, and identify candidates for possible regulation. The UCMR provides occurrence information for determining human exposure, establishing the baseline for health effects and economic analyses, contaminant co-occurrence analyses, and treatment technology evaluation (related to the CCL contaminants). After identifying the top priorities for regulatory determination, EPA begins the process of determining RfDs and associated enforceable standards for protection of public health.

3. Use of Modeling Results

<u>Summary of Comments:</u> One commenter recommended that EPA compare the results of hydraulic fracturing after the process to "modeling" conducted before the process to "provide some degree of predictability of the impact of the fracturing before the actual work is done."

This commenter also recommended that any modeling should consider the effect of other existing activities and conditions that could affect the outcome of the model (e.g., existing oil and gas wells, water wells, location and type of surface structures). This commenter also stated that consideration of the impact of these "man induced activities and conditions" should be an integral part of any fracture program and of any analysis of CBM fracturing impact. This commenter stated that the fracturing process and fluids alone may not cause "harm" within the study's parameters, but when coupled with the existing "man induced conditions" could cause "considerable damage and risk."

EPA Response: As discussed in Chapter 3 of the report, operators use a number of techniques to estimate fracture dimensions to design fracture stimulation treatments. Operators have a financial incentive to keep the hydraulically induced fracture generally within the target coal zone, so that expenditures on hydraulic horsepower, fracturing fluids, and proppants are minimized. For precise and statistically reliable measurements, however, fracture height and length can be measured (as opposed to modeled) accurately by microseismic monitoring. Tiltmeter measurements can also provide fracture height and length measurements somewhat accurately. The results of hydraulic fracturing "after the process" have also been investigated in the mined-through studies by the U.S. Bureau of Mines and others. These studies provide important, directly-measured characteristics of hydraulic fracturing in coal seams and surrounding strata. In addition, paint tracer studies conducted as part of mined-through studies can provide lower bound estimates on the extent of fluid movement.

During its analysis of the threat of CBM fracturing practices on USDWs, EPA considered the impact of human activities (such as improperly sealed or abandoned wells). Chapter 6 of the report summarizes citizen complaints and resulting investigations by state agencies into possible impacts of hydraulic fracturing on drinking water wells and surface waters. In some cases, improperly sealed gas wells have been remediated, resulting in decreased concentrations of methane in drinking water wells.

B. Literature Used for the Study

Summary of Comments: Some commenters indicated that the literature used for the study was outdated. Another commenter questioned whether the search terms that the Agency used to find references for the report would locate "health-related" literature. This commenter also questioned whether the acronym "USDW" and/or "underground sources of drinking water" was used as a search term. Another commenter stated that the report was "simply a compilation of existing data, with no new information, references, or conclusions."

EPA Response: The search terms used by the Agency did not include health-related terms because the study's goals did not include conducting a human-health risk assessment or conducting a new investigation into the toxicity of any of the components of hydraulic fracturing fluids.

As stated in the study design (66 FR 39396)[2], EPA focused the study on a review of existing data. EPA's literature search included publications and documents that were publically available as of December 2000/January 2001. EPA reviewed over 200 peer-reviewed publications. Much of the appropriate literature comes from the mid-1990s when funding was available for this kind of research. EPA also reviewed additional studies recommended by commenters and the peer review panelists, and incorporated information from these documents into the study, when appropriate. Further, EPA obtained information for the study through interviews with approximately 50 employees from industry and state or local government agencies, and communication with approximately 40 citizens and groups who are concerned that CBM production affected their drinking water wells.

C. Basins Included in the Study

Summary of Comments: One commenter questioned why EPA's report only included 11 basins. This commenter indicated that there are 16 separate basins considered to have CBM resources in the lower 48 states. Further, the commenter stated that the Illinois Basin, which was not discussed in the study, is a major coal-bearing region in the central Midwest.

EPA Response: EPA's literature search did not find any CBM activity or hydraulic fracturing in the Illinois Basin. Other basins which have little or no current CBM production activity (e.g., Alaska) were also omitted from the study.

D. Citizen Complaints/Instances of Water Well Contamination

Summary of Comments: Many commenters stated that EPA and state agencies have not done an adequate job of investigating citizen complaints related to contamination of water wells near hydraulically fractured CBM wells. Some commenters also stated that the Agency disregarded these complaints by concluding in its draft report that hydraulic fracturing of CBM wells poses a low risk. Some commenters also believed that the volume of complaints was enough to warrant the need for the Agency to continue its study. One commenter criticized the Agency for only having a 30-day collection period associated with the July 30, 2001 *Federal Register* notice in which the Agency requested information on groundwater contamination incidents that could be due to hydraulic fracturing of CBM wells. This commenter added that EPA's outreach efforts were unlikely to have reached the general public, and also recommended that EPA set up hotlines and make resources available to "allow immediate, comprehensive investigations of citizen complaints related to hydraulic fracturing impacts on USDWs."

Conversely, others commenters indicated that based on the volume of hydraulic fracturing activities, that if the threat to public health from hydraulic fracturing of CBM wells were significant, confirmed instances of water well contamination would exist. Some of these

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[2] US Environmental Protection Agency. 2001. Underground Injection Control; Request for Information of Ground Water Contamination Incidents Believed To Be Due to Hydraulic Fracturing of Coalbed Methane Wells. *Federal Register*. Vol. 66, No. 146. p. 39396, July 30, 2001.

commenters indicated that EPA's report should acknowledge the 1998 study conducted by the Ground Water Protection Council (GWPC), "Survey Results On Inventory and Extent of Hydraulic Fracturing in Coalbed Methane Wells in the Producing States," GWPC (December 15, 1998) because this survey of state oil and gas regulators provides further support for EPA's study conclusions.

<u>EPA Response:</u> The response of state agencies and EPA to citizen complaints are documented in Chapter 6. EPA has responded to complaints, particularly at the Regional level. For instance, in the Powder River Basin, located in Wyoming and Montana, citizen complaints dealt primarily with water quantity issues, which were beyond the scope of this study. EPA Region 8 is participating in a study that addresses the environmental effects of all aspects of CBM development and not just hydraulic fracturing. In response to citizen complaints, the Alabama Department of Environmental Management and EPA Region 4 also conducted independent sampling on wells in the Black Warrior Basin. Water analyses indicated that the wells had not been contaminated as a result of the hydraulic fracturing activities.

In some regions responses to citizen complaints are made primarily at the state level. For example, the Colorado Department of Health and the Colorado Oil and Gas Conservation Commission (COGCC) responds to many complaints. In Colorado, the primary response of the COGCC to citizen complaints has been the remediation of old, improperly sealed gas wells. The remediation of such wells has reduced methane concentrations in approximately 27 percent of the water wells sampled. Reduction of methane concentrations in many of the additional wells is expected over time due to the COGCC's efforts.

Regarding public outreach efforts need improvement, EPA has made considerable efforts to ensure its outreach and communications reach the general public. In addition to making the August 2002 draft available for public comments, EPA's outreach steps included:

- Publishing *Federal Register* notices (EPA's primary mechanism for communicating with the public):
  - requesting comment on how an EPA study should be structured (65 FR 45774)[3];
  - requesting information on any impacts to groundwater believed to be associated with hydraulic fracturing (66 FR 39396) (see footnote 2) including a mailing to over 200 county agencies making them aware of the *Federal Register* notice; and
  - requesting comments on the August 2002 draft of the study (67 FR 55249) (see footnote 1).

- Holding a public meeting on August 24, 2000, to obtain additional stakeholder input on the study. Several of these commenters recommended that EPA's study include accounts of personal experiences with regard to CBM impacts on drinking water wells. These experiences are discussed in Chapter 6.

[3] US Environmental Protection Agency. 2000. Underground Injection Control (UIC) Program; Proposed Coal Bed Methane (CBM) Study Design. *Federal Register*. Vol. 65, No. 143. p. 45774, July 25, 2000.

- Providing periodic updates for stakeholders, including citizens groups, in the form of written communication; and

- Maintaining a Web site where stakeholders can view the project documents; get updates on the progress of the project (including announcements of the release of *Federal Register* notices); and provide information to EPA.

Regarding the comment that EPA only provided 30 days for the public to provide information on CBM-related groundwater contamination incidents following the July 30, 2001 *Federal Register* notice, note that the Agency has considered all complaints received from the public, regardless of the time at which EPA received them. In addition, EPA's Web site www.epa.gov/safewater/uic/cbmstudy.html has a link to a form that allows people to submit information on the potential effects of hydraulic fracturing.

In response to the commenter's suggestion regarding hotlines, EPA has its Safe Drinking Water Hotline, which callers within the United States may reach at (800) 426-4791. Citizens are welcome to contact EPA or the states regarding these issues.

Regarding the comment about the volume of CBM activities and lack of confirmed instances of water well contamination, during its review, EPA found no confirmed cases that are linked to fracturing fluid injection into CBM wells or subsequent underground movement of fracturing fluids. Although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by hydraulic fracturing fluid injection into CBM wells. EPA has included language to that effect in its final report, "Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs", June 2004, EPA document number: EPA 816-R-04-003 (hereafter referred to as final report).

E. Peer Review Panel

Summary of Comments: Many commenters questioned the composition of EPA's peer review panel, who reviewed the initial draft report. These commenters stated that this panel was heavily biased toward industry that has a stake in the outcome of the study. These commenters recommended that EPA convene a panel that is free of conflict of interest. Some recommended using members of the NAS as panelists.

One commenter indicated that he could not ascertain the composition of the panel although Appendix B of the report is supposed to contain a table with the list of the peer review panel. Another commenter stated that EPA made it very difficult for the public to obtain a copy of the peer review report, and that these comments were not attached in an appendix as originally promised.

EPA Response: EPA has a formal Agency Peer Review Policy that establishes the criteria and requirements for independent evaluation of scientific and technical studies and documents. Consistent with that policy, the Agency established a seven-member technical expert peer review panel, who performed a technical review of the study. Panel members were selected by identifying individuals with scientific or technical expertise in hydraulic fracturing through reviewing peer-reviewed publications in scientific journals and through communications with professional societies, trade and business associations, state organizations, and other federal agencies. EPA considered over 20 candidates before selecting 7 individuals based on their experience in the fields of hydraulic fracturing, rock mechanics, and/or natural gas production, and for their varying perspectives (industry, state government, academia, and a national laboratory). The charge to this committee was to review the report to determine if: 1) the report is complete, thorough, and accurate; and 2) the scientific/technical studies reviewed are applied in a sound, unbiased manner.

EPA posted the list of these reviewers and their qualifications on its Web site at www.epa.gov/safewater/uic/cbmstudy.html. EPA inadvertently omitted the table that identifies the peer reviewers in Appendix B of the draft report. This table is included in the final report.

III. FRACTURE FLUIDS

A. Components of Fracturing Fluids

1. Health Effects

Summary of Comments: Many commenters were concerned about the amount and health effects of certain chemicals used in hydraulic fracturing fluids and cited these concerns as reasons to continue the study. Some argued that very small quantities of toxic chemicals, such as benzene or methyl tert butyl ether (MTBE), could contaminate millions of gallons of groundwater.

Other commenters were concerned about the way in which the constituents of fracturing fluids and their potential health effects were presented in the draft report. For example, one commenter wanted the report to clearly convey the following: a wide variety of fracturing fluids exist, the health effects identified in the report apply to only some of the constituents that may or may not be present in the fracturing fluid, the health effects are associated with the product in its "pure form," and all the fluids additives are greatly diluted during fracturing operations.

EPA Response: As discussed in section II.A.2, EPA has recently entered into agreements with three major service companies to voluntarily eliminate diesel fuel from hydraulic fracturing fluids injected directly into USDWs for CBM production. Compounds such as benzene are components of diesel. These agreements will significantly reduce the use of diesel fuel in hydraulic fracturing fluids that are injected directly into USDWs for CBM production.

Chapter 4 of the final report provides a general description of the fate and transport processes which would minimize potential exposure to chemicals used in hydraulic fracturing fluids. Based on a 1991 fracturing fluid recovery study conducted in coal by Palmer et al., as much as 68 to 82 percent of the fracturing fluids may be removed when the methane is extracted.[4] This study is discussed in Chapter 3 of the report. As detailed in Chapter 4 of the report, the

[4] Palmer, I.D., Fryar, R.T., Tumino, K.A., and Puri, R. 1991. Comparison between gel-fracture and water-fracture stimulations in the Black Warrior basin; Proceedings 1991 Coalbed Methane Symposium, University of Alabama (Tuscaloosa), pp. 233-242).

unrecovered fluids will undergo processes that may limit their availability, concentration, and movement. These fluids may be significantly diluted and dispersed as they are transported through the subsurface. They may also interact chemically or physically with geologic material which may retard their movement and further disperse their concentrations.

EPA identified fluids and fluid additives commonly used in hydraulic fracturing through literature searches, reviews of relevant material safety data sheets (MSDSs) provided by service companies, and discussions with field engineers, service company chemists, and state and federal employees. The draft and final reports provide a discussion of the wide variety of hydraulic fracturing fluids that may be used. Table 4-1 of the report lists components that may be contained in fracturing fluids based on MSDSs. The final report emphasizes that not all fracturing fluid constituents, identified in Table 4-1 of this report, may be present in fracturing fluids, that the potential human health effects presented in the table apply to these compounds in their pure form, and that these compounds are significantly diluted prior to use.

An environmental impact statement (EIS) prepared by the BLM also identified MTBE as a compound that may be found in fracturing fluid (U.S. Department of the Interior, CO State BLM, 1998).[5] However, EPA was unable to find any indications in the literature, on MSDSs, or in interviews with service companies that MTBE is used in fracturing fluids to stimulate CBM wells.

2. Diesel Fuel

Summary of Comments: Several commenters supported EPA's recommendation that the industry use "water-based" alternatives in lieu of hazardous constituents such as diesel fuel. Some argued that EPA should make this a requirement and not a recommendation. Some of these commenters pointed to EPA's recommendation to "remove any threat whatsoever" from hydraulic fracturing fluid as a contradiction to the study's conclusions and as a reason to continue the study.

Conversely, several commenters indicated that there are valid reasons for using certain chemicals to enhance CBM production and that in choosing alternatives, the CBM well operators must take into account the specific geologic conditions of the site. These commenters recommended that EPA "encourage flexibility" with respect to the production of methane. One of these commenters noted that the draft report suggests that water-based alternatives are: currently available, feasible, and acceptable substitutes for diesel-based gels. This commenter indicated that the report findings should recognize that more research is needed on these potential alternatives. This commenter added that not all of the potential alternatives to the use of diesel may be water-based, citing polymer-based alternatives as one possibility. This commenter recommended that the term "water-based alternatives" be changed to read "non-diesel-based alternatives."

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[5] U.S. Department of the Interior, Bureau of Land Management, Colorado State Office. 1998. Glenwood Spring Resource Area: Oil & Gas Leasing Development, Draft Supplemental Environmental Impact Statement, June 1998.

One commenter indicated that in the State of Alabama, diesel is not used nor is it approved for hydraulic fracturing. The commenter added that service companies in his state primarily use a linear gel composed of guar gum, a surfactant, and silica.

EPA Response: The discussion of potential alternatives to the use of diesel is not included in the final report because it is outside the scope of the study. Instead, the report highlights the MOA with three major service companies to voluntarily eliminate the use of diesel fuel in hydraulic fracturing fluids injected directly into USDWs for the purpose of CBM production and if necessary, select replacements that will not cause hydraulic fracturing fluids to endanger USDWs (see the response to comment in section II.A.2).

Regarding the comment on the use of diesel in the State of Alabama, Table A2-1 in Attachment 2 of the draft and final report indicates that diesel is not used in that state.

3. MTBE

Summary of Comments: Several commenters were concerned about the use of MTBE in fracturing fluids. Many of them included the following statement in their comments: "only 28 tablespoons of MTBE could contaminate millions of gallons of groundwater."

One commenter indicated that the report contains several inconsistent statements regarding MTBE as a component of fracturing fluids. This commenter noted that in Chapter 4 of the draft report, EPA states that, based on its literature reviews and interviews with service companies, the Agency did not find any evidence that MTBE is used in fracturing fluids. This commenter also indicated that later in the same chapter, EPA states that "some gelling agents can contain hazardous substances including . . . [MTBE.]," and cites as its source a Supplemental EIS issued by BLM. This commenter provided arguments why he believed that the supplemental EIS was in error in listing MTBE as a potential component in fracturing fluids. This commenter further recommended that EPA should not have used this EIS as a source for identifying constituents in fracturing fluids or at a minimum, should have indicated the shortcomings associated with using this type of document to determine the components of fracturing fluids. This commenter provided a detailed discussion of some of the problems with using this particular EIS.

EPA Response: As stated in the response to comment in section III.A.1, an EIS prepared by the Colorado State BLM (1998) identified MTBE as a compound that may be found in fracturing fluid. EPA found no information in the literature, MSDSs, or through interviews with service companies indicating that MTBE is used in fracturing fluids to stimulate CBM wells. MTBE is not used during the manufacture of diesel fuel. It is generally only added to gasoline. However, in an effort to be fully inclusive of all the Agency's literature search findings, EPA included the information found in the EIS and noted that EPA was not able to confirm MTBE use in fracturing fluids.

B. Comparison of Concentrations of Hydraulic Fracturing Fluid Components to MCLs

Summary of Comments: A few commenters questioned the appropriateness of EPA's use of MCLs to compare the projected concentrations of fracturing fluids that may be injected into

USDWs. The commenters argued that MCLs apply to "treated water" and that the water associated with the formations in which hydraulic fracturing occurs would not be suitable for drinking water without first being treated.

EPA Response: Under the mandate of SDWA, EPA establishes MCLs as enforceable maximum permissible levels for contaminants in drinking water, to ensure the safety of public drinking water supplies. Because the concern about contamination relates to USDWs, which are actual or future supplies of drinking water for human consumption, MCLs are used in this study as standard reference points to compare calculated or anticipated levels of contaminants in hydraulic fracturing fluids and in the subsurface. MCLs provide a context for discussions regarding the concentrations of individual contaminants.

C. Concentrations of Constituents in Fracturing Fluids/Fluid Recovery Rates

1. Estimates of Concentrations of Constituents in Fracturing Fluids

Summary of Comments: EPA received several comments on its estimates of the concentrations of the constituents of concern in fracturing fluids that may be present at the point-of-injection and at the edge of the fracture zone. Many commenters were alarmed about the estimated concentrations of some of these constituents such as benzene because they were above the MCL. Further, some were concerned that EPA had revised its estimates since publication of the report. Conversely, other commenters indicated that EPA had overstated these concentrations. Each of these comments is discussed in more detail below.

One commenter indicated that EPA's estimates for the constituents of concern at the edge of the fracture zone, which assume a dilution factor of 30, still exceed drinking water standards for benzene, aromatics, 1-methylnapthalene, and methanol. This commenter added that EPA estimated high concentrations for the estimated point-of-injection for some chemicals for which drinking water standards have not yet been developed. This commenter acknowledged that these concentrations will be reduced as they mix with groundwater; however, he stated that very small amounts of some chemicals like benzene and MTBE can contaminate millions of liters of groundwater. Further, this commenter noted that most CBM wells are hydraulically fractured more than once, and therefore, "the groundwater in which it resides," will receive multiple doses of the fracturing fluids chemicals. The commenter stated a figure from the report that between 50,000 and 350,000 gallons of fracturing fluids are typically used in coalbed fracture treatments. Another commenter indicated that the report does not recognize that some of the constituents in fracturing fluids may affect human health at very low concentrations. This commenter added that with the potentially thousands of CBM wells being developed, the problem is magnified.

Several commenters claimed that EPA revised its calculations after the draft report was released. Some of these commenters indicated that EPA changed its scientific and policy conclusions under pressure from industry. One commenter provided detailed comments on the revised calculations. This commenter argued that EPA changed some of the parameters that were used in the draft report (such as length and height of a fracture, volume of injected hydraulic fracturing fluids, percentage of unrecovered hydraulic fracturing fluids) and they resulted in smaller estimated concentrations, including a revised estimate for benzene that does not exceed the MCL. This commenter questioned the basis for EPA's revising its estimates.

Other commenters were concerned that EPA did not adequately explain the assumptions used to generate its calculations. For example, one commenter indicated that it was unclear whether EPA based its estimates at the edge of the fracture zone on a specific fracture length or fracture radius. Some commenters also stated that EPA did not consider factors that would influence the availability and decrease the concentrations of the constituents at the edge of the fracture zone. These factors included: the recovery of the majority of the fracturing fluid, the relatively low permeability of coalbed formations will limit the movement of groundwater away from the wellbore, the coal will adsorb some of the constituents onto its surfaces, acids react with certain rock constituents and become spent, and some fracturing fluid constituents such as benzene will biodegrade. Some commenters also recommended that EPA's report should further emphasize that any constituents of concern in fracturing fluids are present only in very minimal amounts.

One commenter indicated that EPA had "significantly mischaracterized the nature of its estimates at both the point-of-injection and the edge of the fracture zone" because EPA had used a "worst case" scenario for estimating these concentrations. The commenter stated that, although the report indicates that EPA used mid-range values, the Agency used the maximum amount of diesel fuel that service companies reported to EPA instead of an average value. This commenter also explained why he believed that some of the point-of-injection concentrations that were presented in Table 4-2 of the draft report, such as that estimated for methanol, appeared to be inconsistent with the discussion in the text. Further, this commenter also recommended that EPA include its newer calculations in the report.

<u>EPA Response:</u> The values presented in the draft report are oversimplified estimates based on dilution alone and are not accurate enough to predict that a 30 times decrease is above or below the MCL. In the final report, EPA has revised its procedure for assessing the potential effect of fracturing fluid constituents on USDWs from that presented in the August 2002 draft as follows:

- The draft report included point-of-injection calculations for all constituents that may be contained in fracturing fluids. The final report focuses only on those constituents for which MCLs are established (i.e., BTEX compounds).

- EPA has revised the fraction of BTEX compounds in diesel used to estimate the point-of-injection concentrations from a single value to a documented broader range of values for the fraction of BTEX in diesel fuel. For example, the fraction of benzene in diesel was revised from $0.00006 g_{benzene}/g_{diesel}$ to a range with a minimum value of $0.000026\ g_{benzene}/g_{diesel}$ and a maximum value of $0.001\ g_{benzene}/g_{diesel}$. If the maximum value for benzene in diesel is used to estimate the concentration of benzene at the point-of-injection, the resulting estimate is 17 times higher than that presented in the draft report.

- In the final report, EPA used more current values for two of the parameters used to estimate the point-of-injection concentrations of BTEX compounds. Specifically, the estimates in this report use a density of the diesel fuel-gel mixture of 0.87 g/mL compared to 0.84 g/mL in the draft report, and a fraction of diesel fuel in gel of 0.60 g_{diesel}/g_{gel} compared to 0.52 g_{diesel}/g_{gel} in the draft report. The use of these more current values does not affect the order of magnitude of the revised point-of-injection calculations.

- The August 2002 draft report included estimates of the concentration of benzene at an idealized, hypothetical edge of the fracture zone located 100 feet from the point-of-injection. Based on new information and stakeholder input, EPA concluded that the edge of fracture zone calculation is not an appropriate model for reasons including:

  - Mined-through studies reviewed by EPA indicated that hydraulic fracturing injection fluids had traveled several hundred feet beyond the point-of-injection.

  - The assumption of well-mixed concentrations within the idealized fracture zone is insufficient. One mined-through study indicated an observed concentration of gel in a fracture that was 15 times the injected concentration, with gel found to be hanging in stringy clumps in many fractures. The variability in gel distribution in hydraulic fractures indicates that the gel constituents are unlikely to be well mixed in groundwater.

  - Based on more extensive review of the literature, the width of a typical fracture was estimated to be much thinner than that used in the draft report (0.1 inch versus 2 inches). The impact of the reduced width of a typical fracture is that the calculated volume of fluid that can fit within a fracture is less. After an initial volume calculation using the new width, EPA found that the volume of the space within the fracture area may not hold the volume of fluid pumped into the ground during a typical fracturing event. Therefore, EPA assumes that a greater volume of fracturing fluid must "leakoff" to intersecting smaller fractures than what was assumed in the draft report, or that fluid may move beyond the idealized, hypothetical "edge of fracture zone." This assumption is supported by field observations in mined-through studies, which indicate that fracturing fluids often take a stair-step transport path through the natural fracture system.

- In the draft report, EPA approximated the edge of fracture zone concentrations considering only dilution. Based on new information and stakeholder input on the draft report, EPA does not provide estimates of concentrations beyond the point-of-injection in the final report. Developing such concentration values with the precision required to compare them to MCLs would require the collection of significant amounts of site-specific data. This data in turn would be used to perform a formal risk assessment, considering numerous fate and transport scenarios. These activities are beyond the scope of Phase I of this study.

- In Chapter 4 of the final report, EPA provides a qualitative evaluation of the fate and transport of unrecovered fracturing fluids on residual concentrations of BTEX in groundwater. EPA describes in Chapter 4 how subsurface flow would significantly disperse and dilute BTEX compounds in groundwater, minimizing potential exposure to these constituents. BTEX compounds may also interact chemically or physically with geologic material which may retard their movement and further disperse their concentrations.

See also EPA's response to comment in section III.A.1 of this document.

No data or conclusions in the final report or in any previous draft were altered to accommodate any industry parties, states, environmental groups, or others. This study was a thorough and transparent data collection and technical evaluation exercise. The report and its conclusions were prepared by career technical staff at EPA.

The study was designed based upon a transparent process including public comment on the conceptual study design which included comments from state drinking water and oil and gas agencies, industry, environmental groups, and private citizens. EPA consulted with experts in the United States Geological Survey and the Department of Energy. Consistent with principles of good science, a draft of the study was subjected to a technical peer review from hydraulic fracturing experts. The conclusions of the study were not submitted for review to any private sector parties.

2. Fluid Recovery Rates

Summary of Comments: Many commenters were concerned that a large percentage of fracturing fluid remains behind and is available to potentially migrate into USDWs, citing these concerns as a reason to continue EPA's study. Some commenters indicated that EPA was inconsistent in the recovery percentages that the Agency cited in the report. Two commenters noted that the recovery experiment that is referenced in the report only ran for 19 days and that additional fracturing fluids may be recovered after that time. Another commenter stated that one fluid recovery rate (i.e., 61 percent) should not be "indiscriminately applied to over 14,000 CBM wells."

Some commenters cited a study by three Amoco scientists in which the study found "that a significant volume of fracturing fluids is not withdrawn." These commenters explained that the scientists found that the gelling agents used in the fracturing fluids remained in the coal samples although they had been flushed with water and strong acids. The commenters argued that, since these chemicals are not fully recovered, they could "serve as continuous sources of groundwater contamination."

EPA Response: Section III.A.1 provides a discussion of processes that can limit the availability, concentration, and movement through groundwater of unrecovered fracturing fluids. EPA has ensured that the recovery percentages cited in the report are both internally consistent and consistent with the literature reviewed. Three studies on recovery rates of hydraulic fracturing fluids were reviewed in Chapter 3 of the report. Only one of these studies, Palmer et al., 1991, involved hydraulic fracturing of coalbeds (refer to footnote 1 for the study reference). Thus, the Palmer study was considered the most relevant of the three studies for the purposes of this report. The final report clarifies that the recovery rate of 61 percent was based on a 19-day flowback period. Palmer et al., 1991, predicted recovery rates as high as 82 percent over a longer recovery period.

Regarding the study by three Amoco scientists, EPA contacted one of the commenters to obtain a copy of the study to review.[6] The commenter was unable to provide the study and EPA's additional library research efforts were also unsuccessful at obtaining this study.

3. Amount of Fracturing Fluids

Summary of Comments: Some commenters were concerned about the volume of fracturing fluids used in a "typical fracturing job" and cited the following statement from the report, "Coalbed fracture treatments typically use 50,000 to 350,000 gallons of various fracturing fluids, and from 75,000 to 320,000 pounds of sand as proppant... ." Others questioned the accuracy of the quantities of fracturing fluid and proppant cited in the report, stating that these figures were more consistent with a massive hydraulic fracture. Another commenter stated that the unique properties that make many coal formations effective receptacles for methane also allow them to hold large quantities of water. This commenter stated that injection of hydraulic fracturing fluids into USDWs risks permanent contamination of these USDWs because fracturing fluids often contain large amounts of toxic chemicals.

EPA Response: EPA has clarified in the final report that more typical injection volume may be closer to a maximum of 150,000 gal/well, and a median value of 57,500 gal/well. These values are based on average injection volume data provided by Halliburton for six CBM locations.

Refer to section III.A.1 regarding factors that would influence the availability, concentration, and movement of fracturing fluids and their constituents.

4. Movement of Fracturing Fluids

Summary of Comments: Some commenters stated that unrecovered fracturing fluids will flow toward the well because of the pressure gradients. Others noted that this was only true while the well was in production. These commenters argued that once pumping stops, the aquifer will attempt to resume a normal flow pattern and the remaining hydraulic fracturing fluids will move freely within the coalbed formation.

EPA Response: Chapter 4 of the final report has been expanded to more clearly explain:

- hydraulic gradients that occur during injection versus those during fluid recovery;
- the significance of the capture zone of the production well on fracturing fluid recovery (i.e., the portion of the aquifer that contributes water to the well); and
- the movement of fracturing fluids (and what influences their movement) both inside and outside the capture zone.

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[6] Puri, R., G.E. King, and I.D. Palmer, 1991, "Damage to Coal Permeability During Hydraulic Fracturing," Society of Petroleum Engineers Proceedings from Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium, Denver, CO, p. 109-115, (SPE #21813).

IV. FRACTURE BEHAVIOR AND PRACTICES

A. Fracture Growth

Summary of Comments: EPA received many comments on the statements in its report that, "Vertical fracture heights in coalbeds have been measured in excess of 500 feet and lengths can reportedly reach up to 1,500 feet." Some of these commenters stated that these distances indicate the potential for communication with and contamination of USDWs. Other commenters believed that these measurements were incorrect. Some commenters also discussed whether confining layers act as barriers to vertical fracture growth.

One commenter described in detail why he believed that confining layers above and below the hydraulically fractured coal formations would also be fractured and permeated by fluids. This commenter noted that the fracture heights cited in the report exceed the thickness of the thickest coal formations identified in the report. In addition, this commenter noted that the report indicates that some of the coal seams are bounded by sandstone and conglomerate (which have different lithological properties, and therefore different fracturing properties, than shale). Further, he indicated that the report supports his position that the risk for migration of fracturing fluids into adjacent USDWs is significant because it indicates that "Stimulation fluids in coal penetrate from 50 to 100 feet away from the fracture and into the surrounding formation. In these and other cases, when stimulation ceases and production resumes, these chemicals may not be completely recovered and pumped back to the CBM well, and, if mobile, may be available to migrate through an aquifer." This commenter also noted that the report shows that many of the coal formations are located in mountainous regions such as the Rocky Mountains and Appalachian Mountains. The commenter stated that the rock formations in these regions, including the coal formations, have been subjected to intense orogenic and tectonic stress resulting in regional, systematic fractures and faults. The commenter argued that it is likely that coal formations, and other rocks above and below them, are characterized by cracks and fractures, and that because of these deformation features, rates of groundwater transport tend to be higher.

One commenter indicated that the report's description of how fractures travel is incorrect (i.e., they travel horizontally vs. vertically). This commenter added that there is some vertical expansion as the fracture moves horizontally but that this is not the primary direction of fracturing. This commenter stated that their state geologists estimate vertical fracture heights at 50 to 60 feet. Another commenter provided detailed comments on the studies that were conducted on fracture height growths. This commenter indicated that he had been involved in numerous fracture experiments (in all types of reservoirs) where the fracture height has actually been measured (using microseismic or downhole tiltmeter), as well as in mineback tests where hydraulic fractures have been excavated. Based on his experience, the fracture height has always been less than or equal to the height that would be predicted by just using stresses in the various layers (which the commenter indicated was the only factor considered in all the references used in the draft report). The commenter reported that in some cases, the differences were factors of two or three. This commenter also provided detail on factors that influence fracture height growth, such as horizontal stress in the coal, the horizontal stress in the surrounding layers, the characteristics of the layering, and the type of hydraulic fracturing fluids being pumped.

Another commenter noted that the discussion on fracture dimensions in the report was based on literature from 1993 and earlier, but acknowledged that there were "virtually no post-1993 published reports on hydraulic fracturing." The commenter recommended that EPA contact operators, service companies, and state regulatory agencies for current practices and models. Further, this commenter noted that newer data based on more sophisticated FracPro models are available for many basins. He added that, in his state, model results indicate that fracture height is "generally less than 100 feet, whereas fracture half length is typically between 150 and 700 feet." This commenter also noted that the report should state that the fracture heights have been "modeled" not "measured" because vertical fracture heights have never been fully measured in the field.

EPA Response: EPA has revised Chapter 3 to provide clarification on the characterization of fracturing behavior during hydraulic stimulations. The statement that fractures have been "measured in excess of 500 feet and lengths can reach up to 1,500 feet" has been removed because it refers to modeled estimates, rather than direct measurements. Instead, the results of 22 mined-through studies have been summarized, because they provide direct measurements of the dimensions of hydraulic fractures, as well as lower bounds on the extent of fracturing fluid movement. Chapter 3 has also been revised to better distinguish between fracture characterizations based on modeling vs. those that are directly measured.

In addition, EPA has revised Chapter 3 to clarify the issue of hydraulic barriers and barriers to fracture growth above coalbeds. EPA agrees with the commenter that when shales overlying targeted coals are extensively fractured, they may not act as barriers to hydraulic fracture growth or as hydraulic barriers. On the other hand, thick, relatively unfractured shale may present a barrier to upward fracture growth because of the stress contrast between the coalbed and the overlying shale. Deep vertical fractures can propagate vertically to shallower depths and develop a horizontal component. In the formation of these "T-fractures," the fracture tip may fill with coal fines or intercept a zone of stress contrast, causing the fracture to turn and develop horizontally, sometimes at the contact of the coalbed and an overlying formation.

B. Multiple Fractures

Summary of Comments: Some commenters raised concern over the statement in the draft report that "each well, over its lifetime is fractured several times" and urged EPA to continue to Phase II of the study. Others questioned the accuracy of EPA's statement that wells are fractured multiple times. One commenter indicated that in their state, most wells have not been re-fractured multiple times but that instead, two to four coal groups were generally fractured in each well.

EPA Response: EPA has revised the statements regarding multiple stimulations in Chapter 3. In the draft report EPA stated that "many coalbeds are refractured at sometime after the initial treatment." The text has been revised to indicate that the literature on refracturing that was reviewed pertains only to the Black Warrior Basin. EPA's extensive literature review did not find any information indicating that wells are fractured multiple times in any basin other than the Black Warrior Basin.

C. Relationship of Drinking Water Wells to Hydraulic Fracturing Activities

Summary of Comments: Some commenters were concerned about the potential for fracturing fluids to contaminate USDWs due to the high occurrence of coal reservoirs within USDWs. One commenter cited a statement from the report "if coalbeds are located within USDWs, then any fracturing fluids injected into coalbeds have the potential to contaminate the USDW." The commenter added that the report indicates that as much as 91 percent of U.S. coal reservoirs may be located within USDWs.

Two commenters indicated that hydraulic fracturing activities take place at depths far below groundwater sources used as drinking water sources. One of these commenters added that his company's records show that it conducts hydraulic fracturing at shallow depths, (i.e., less than 300 feet below ground surface), in less than one percent of all hydraulic fracturing jobs. This commenter provided this as one reason that he believed that hydraulic fracturing is unlikely to pose a threat to drinking water.

EPA Response: EPA found that 10 of the 11 coal basins, included in the study, may lie, at least in part, within USDWs. Given the concerns associated with the use of diesel fuel and the introduction of BTEX constituents into USDWs, EPA negotiated an MOA with three major hydraulic fracturing service companies for the voluntary elimination of diesel fuel in hydraulic fracturing fluids injected directly into USDWs for the purpose of CBM production. Nevertheless, even when fracturing fluids are injected directly into coalbeds located in USDWs, fracturing fluid components are likely to be significantly diluted and dispersed, as well as subject to other fate and transport processes (discussed in Chapter 4) which are likely to lower their concentrations or prevent their mobility underground. Also see the response to comment in section III.A.1.

D. Differences in State Geology

Summary of Comments: Several commenters indicated that the report did not adequately address the variability present in the different geologic formations that are subject to hydraulic fracturing, and therefore, did not address the possible impacts associated with that variability regarding regional groundwater flow and/or the occurrence and distribution of CBM resources, on assessing the potential threat of hydraulic fracturing on USDWs. One commenter indicated that to accurately represent the threats to USDWs, risk levels should be "differentiated based on modeling and actual data on similar geologic conditions."

EPA Response: EPA agrees that variability of geologic formations and regional groundwater flow are key to the assessment and understanding of the potential threat to USDWs posed by hydraulic fracturing. The study findings and conclusions are based on literature from each of the 11 major coal basins in the United States. In addition, the draft and final report contains separate attachments which discuss basin-specific geologic and hydrogeologic investigations related to each of the 11 basins. The discussions provided were intended to characterize regional coal basin methane production with respect to its effect on USDWs and to supplement the generalized information provided within the body of the report. EPA also agrees that if modeling risk levels, the variability of geologic conditions should be considered. However, such a modeling exercise is beyond the scope of the current study.

V. REGULATION OF HYDRAULIC FRACTURING PRACTICES

A. States' Authority

Summary of Comments: Several commenters recommended that EPA expand its discussion in the final report of the states' role in regulating hydraulic fracturing. Others suggested clarifying the language from the draft report regarding states' authority to regulate hydraulic fracturing. For example, one commenter indicated that EPA's statement, "States with primacy for their UIC program enforce and have the authority to place controls on any injection activities that may threaten USDW's" implies that state UIC Programs can or would regulate hydraulic fracturing. The commenter recommended that EPA add clarifying language that removes the implication that hydraulic fracturing is commonly regulated under UIC Programs.

One commenter stated that the report was inaccurate in its description of Virginia's authority to place restrictions on the depth at which hydraulic fracturing can occur. The commenter indicated that the "restrictions" are instead voluntary procedures. The commenter also clarified the purpose of these procedures.

EPA Response: EPA did not conduct a systematic review of state regulations of hydraulic fracturing and, therefore, has no basis for expanding its discussion of the state's role in the regulation of hydraulic fracturing. However, the Agency added clarifying language regarding the state's ability to regulate hydraulic fracturing. EPA also added clarifying wording to the report regarding Virginia's voluntary program.

B. Regulation of Hydraulic Fracturing under SDWA

Summary of Comments: Several commenters wanted EPA to regulate hydraulic fracturing of CBM wells under SDWA and did not believe that recommended measures such as using "water-based alternatives" instead of diesel were sufficient. One commenter stated that based on *Legal Environmental Assistance Foundation, Inc. v. U.S. E.P.A.*, 118 F.3d 1467, 1470 (11th Cir. 1997), EPA is to decide how to regulate hydraulic fracturing under SDWA, and not to determine whether "further investigation was necessary to evaluate any potential threats" before EPA acts. Another commenter was concerned whether EPA was using the presence of documented cases of "health harm from non-regulation" as the criterion for determining whether to regulate hydraulic fracturing injection activities under SDWA. This commenter argued that the purpose of the UIC Program is "to forestall and prevent such harm by isolating the injected fluids from aquifers that are or could be developed as USDWs"; and therefore, using proven harm as a regulatory threshold goes against the purpose and intent of the law.

Conversely, other commenters indicated that EPA should "recognize the need for industry to be allowed reasonable flexibility in the means that its uses to produce CBM." These commenters also indicated that under 42 U.S.C. § 300h(b)(2), Congress intended that EPA not impose restrictions through the UIC Program that interfere with or impede activities related to oil and gas development unless such restrictions are essential for preventing endangerment of drinking water sources. Another commenter specifically recommended that UIC permits not be required for hydraulic fracturing practices.

EPA Response: Based on the information collected and reviewed, EPA has determined that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs. Continued investigation under a Phase II study is not warranted at this time. The lack of confirmed incidents of drinking water well contamination due to hydraulic fracturing fluid injection from past hydraulic fracturing activities was one among many factors EPA considered. If threats to USDWs from hydraulic fracturing of CBM wells were significant, EPA would expect to have found confirmed instances of drinking water well contamination from the practice. Although thousands of CBM wells are fractured annually, EPA did not find confirmed evidence that drinking water wells have been contaminated by the injection of hydraulic fracturing fluids into CBM wells.

EPA's recent agreements with three major service companies, discussed in section II.A.2, will significantly reduce the use of diesel fuel in hydraulic fracturing fluids that are injected directly into USDWs for CBM production.

It is important to note that states with primary enforcement authority (primacy) for their UIC Programs implement and enforce their regulations, and have the authority under SDWA to place additional controls on any injection activities that may threaten USDWs. States may also have additional authorities by which they can regulate hydraulic fracturing. With the expected increase in CBM production, the Agency is committed to working with states to monitor this issue.

VI. LANGUAGE USED IN THE REPORT

A. Use of the Term "USDW"

Summary of Comments: Some commenters indicated that EPA used the term "USDW" too broadly. In particular, one commenter indicated that the report "carelessly utilizes the USDW term in the context of hydrocarbon bearing formations." This commenter added that these hydrocarbon-bearing aquifers subjected to hydraulic fracturing are unlikely to be used for drinking water, especially without treatment for two reasons: 1) the high total dissolved solids level of the waters in these formations; 2) the waters in these formations may be considered an "exempted aquifer" under SDWA because the aquifer is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated to be commercially producible. This commenter also stated that the inferences in the report, that some risks may be attributed to hydraulic fracturing, conflict with "the reality that such a formation would not be used for water supply without treatment, if it were ever to be used."

EPA Response: EPA disagrees that it has applied the term "USDW" too broadly in the report. SDWA mandates the protection of USDWs from injection activities – "if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any PWS of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons." The broad definition of a USDW by Congress was to ensure that future USDWs would be protected, even where those aquifers were not currently used as a drinking water source or could not be used without some form of water treatment such as desalination. It is also important to note that an exempted aquifer is a USDW, but is exempt from regulation.

B. Use of Scientific Terms

Summary of Comments: A few commenters provided corrections to some of the terminology used in the report. One commenter felt that there was a general misuse of geologic terminology in the report, and specifically indicated that the geologic terms "system," "formation," and "seams" should not have been used interchangeably. This commenter provided other specific clarifications or corrections to some of the discussions in the report (e.g., Section 3.1 regarding the depositional history of coal-bearing rocks in the United States).

EPA Response: EPA appreciates the careful review of the report by many of the commenters. EPA has revised some of the terminology used in the report and incorporated some of the clarifications suggested by the commenters.

C. Use of Qualifying Language

Summary of Comments: Both the commenters that supported EPA's conclusions and those who opposed it indicated that the tone of the language used throughout the report conflicted with EPA's conclusions. Commenters cited examples of this language that included the following:

- "Based on the information collected, the potential threats to USDWs posed by hydraulic fracturing ***appear to be low*** and do not justify additional study.";
- ..."the ***apparent risk*** to public health from hydraulic fracturing is not compelling enough to warrant expending resources on a phase II effort"; and
- "***the apparent threat*** to public health from hydraulic fracturing."

One of the commenters indicated that this language showed "a weak articulation of EPA's confidence in its own report." Many of the commenters who were opposed to EPA's findings, pointed to EPA's qualified statements as a reason to continue the study.

Another commenter, who supported EPA's findings, stated that the primary definition of the word, "apparent," is, "something that is clearly seen or understood, obvious, self-evident, glaring." This commenter, among others who supported the Agency's findings, recommended that EPA replace all uses of the word "apparent" when describing the threat posed to USDWs by hydraulic fracturing with words that more accurately describe the low likelihood of this threat.

EPA Response: In the final report, EPA has eliminated the use of the word "apparent" and "appears" to describe its study conclusions and has made the language more consistent with the report's results.

VII. CHAPTER-SPECIFIC COMMENTS

This summary of chapter-specific comments focuses mainly on those comments that have not been summarized within the issue-specific Sections II through VI of this document. Comments were received on almost every chapter of the document, ranging from minor editorial suggestions, to factual corrections. EPA appreciates the thorough comments that were submitted regarding the contents of the hydraulic fracturing report. The Agency has considered all comments, researched the accuracy of some comments (where necessary), and incorporated comments where appropriate.

A. Glossary

Summary of Comments: One commenter submitted recommended changes to the list of acronyms and abbreviations, and the glossary pertaining to "M"; "KCl"; "pad"; and the phrase, "wells that have been 'screened-out' cannot be used for gas production."

EPA Response: After reviewing and checking on the accuracy of the above comments, EPA incorporated changes to the glossary and list of acronyms, where appropriate.

B. Other Executive Summary Comments

Summary of Comments: EPA received many comments that were specific to the executive summary of the report, including recommendations for revising the text, tables, and figures. A few commenters suggested that the language regarding the findings and conclusions of the study needs to be clearer and stronger (e.g., qualifiers such as "appear to be low" and "persuasive evidence" weakens the conclusions). Another suggested that, in general, the executive summary and the main document need to point out that not all USDWs are currently being used nor will they ever be used as sources of drinking water. Some commenters felt that the executive summary was inappropriately long and provided suggestions for making the section shorter, including eliminating all tables from this section. Many commenters provided specific editorial comments.

A few commenters expressed concern regarding the "graphic language" in Table ES-2 *(Summary of MSDSs for Hydraulic Fracturing Fluid Additives)* used to describe the health effects of fracturing fluids, and noted that they felt it may be unnecessarily alarming, and potentially misleading to readers (i.e., it does not clarify that the health effects only pertain to some constituents that may or may not be present in the fracturing fluids). Commenters added that Table ES-2 suggests that linear gel delivery systems always contain diesel and does not indicate that fluid additives are greatly diluted. One commenter felt that the information provided in Table ES-4 *(Evidence in Support of Coal-USDW Co-Location in U.S. Coal Basins)* was too general, and believed that the information should just be presented in the more detailed sections from which it was summarized. Other commenters were concerned that the information provided in Table ES-5 *(Summary of Reported Incidents that Associate Water Quality/Quantity with Coalbed Methane (CBM) Activity)* could be misleading to the public.

One commenter felt that the executive summary figures in general were "confusing and misleading." Other commenters questioned the accuracy and clarity of Figure ES-2 *(Graphical Representation of the Hydraulic Fracturing Process in Coalbed Methane Wells)*, which depicts drinking water wells drawing down into coal seams. One commenter questioned the accuracy of the illustrations in Figures ES-3 *(Direct Fluid Injection into a USDW (Coal within USDW))* and ES-4 *(Fracture Creates Connection to USDW)* regarding the depth of the water wells and the direction of fluid migration (i.e., fracturing fluids are shown to be flowing away from the well bore toward the drinking water wells). The commenter pointed out that the descriptive text on page ES-10 conflicts with the depiction of fluid migration in Figure ES-4.

EPA Response: EPA has reviewed and considered all comments regarding the executive summary of the document. The Agency originally designed the executive summary to be a stand-alone document. Because many readers of such a document (such as Congress or the leaders of various stakeholder organizations) may have limited time to dedicate to the review of a large technical document, EPA included essential summary information, including tables and figures, in the executive summary. However, based on the comments received, EPA has pared down the executive summary by taking out most of the tables and summarizing key information from these tables in narrative form. EPA incorporated many of the specific suggestions related to the figures (e.g., decreasing the depth of drinking water wells), and in some instances, provided clarifying language to explain the figures.

C. Other Chapter 1 Comments (Introduction)

Summary of Comments: A few commenters provided comments regarding the Introduction to the hydraulic fracturing report. Comments included questions about the accuracy of the figures, and how they were depicted: groundwater flow; the relation between well depths and coal seams; and the point-of-injection for the fracturing fluids. One commenter objected to the statement that the study was "based on a high level of interest of stakeholders..." when it was the commenters' understanding that it was based only on a "handful" of complaints.

EPA Response: The statement that the study was "based on a high level of interest of stakeholders..." is an accurate statement but the term "stakeholders" was vague. To be more descriptive, Chapter 1 of the final report indicates that a reason for conducting the study was "concerns voiced by individuals who may be affected by coalbed methane development. . ." The Agency addressed each of the other comments by either incorporating suggested language or making relevant clarifications in the document language and figures.

D. Other Chapter 2 Comments (Methodology)

No substantive comments received on this chapter.

E. Other Chapter 3 Comments (Characteristics of CBM Production and HF Practices)

Summary of Comments: EPA received several comments regarding the information in Chapter 3. In particular, several commenters questioned the study's assumptions regarding recovery rates and fracture heights. A more detailed summary of the comments received on these topics can be found in sections III.C.2 and IV.A, respectively. One commenter had several specific questions regarding statements made in this chapter, including: the meaning of the term "conventional coal mines"; statements regarding the number of CBM wells in Alabama; the discussion of the origin of CBM; the statement that "coal has very little natural permeability"; contradictions between the discussion of fluids migration in this chapter compared to that shown in Figures ES-4 and 1-3; accuracy and clarity of statements regarding the rate of fluid recovery; and the statement that many CBM wells are re-fractured.

EPA Response: EPA appreciates the detailed comments that were submitted regarding Chapter 3 of the hydraulic fracturing report. The Agency made several editorial corrections and clarifications to this chapter based on these comments. A more detailed response regarding recovery rates, fracture heights, and re-fracturing of the same wells can be found in sections III.C.2, IV.A, and IV.B, respectively.

F. Other Chapter 4 Comments (HF Fluids)

Summary of Comments: Comments specific to Chapter 4 of the report included questions about the calculation of the constituents of concern at the point-of-injection, and other editorial comments and suggestions.

EPA Response: In response to comments received on Chapter 4, EPA has incorporated clarifying language regarding its calculations of BTEX compounds at the point-of-injection. Other editorial corrections and clarifications have also been incorporated. For a discussion of how EPA revised its procedure for assessing the potential effect of fracturing fluid constituents on USDWs from that presented in the draft report, refer to section III.C.1.

G. Other Chapter 5 Comments (Basin Descriptions)

Summary of Comments: Several comments were received regarding the basin descriptions, including updates from a few states on the numbers of wells in the applicable basins. One commenter suggested additional references that should be used to correct some of the statements regarding the Pottsville Formation. The other four commenters each provided specific editorial suggestions on one of the following four basins: the Central Appalachian Basin, the Northern Appalachian Basin, the Uinta Basin, and the Powder River Basin.

EPA Response: EPA has incorporated the updated well information provided by states. All other editorial comments were considered, and most were incorporated. Other basin-specific issues are discussed in section VIII of this document.

H. Other Chapter 6 Comments (Water Quality Incidents)

Summary of Comments: Several comments were received regarding the water quality incidents chapter of the report. Commenters made specific editorial suggestions, and provided clarifications about specific complaints, additional information about how their state investigates complaints, and information about state-specific hydraulic fracturing regulations. One commenter stated that the discussion of the Pottsville, Allegheny, Conemaugh, and Monongahela Groups were "oversimplified" and questioned the conflicting use of the terms "cyclothem" and "complex" when describing the depositional environments of the Allegheny Group.

A few commenters expressed concern that the descriptions of public complaints (including the information summarized in Table 6-2) are presented in the report as if the information was factual, without linking the complaints to actual findings following the state and EPA investigations. One commenter indicated that EPA does not present any data from state agencies, which suggests to the commenter that no real scientific studies were conducted. Commenters recommended that the complaints be immediately followed by a summary of the evaluation and resolution of the complaint. One recommendation was that, if kept in the report, the information be moved to an appendix.

Finally, some commenters felt that EPA was contradictory regarding the question of whether hydraulic fracturing of CBM wells threaten USDWs. For example, one commenter indicated that EPA had concluded in Chapter 6 that there is insufficient evidence to determine if there is a link between fracturing and USDW contamination. However, elsewhere in Chapter 6, EPA states that "water quality problems might be associated with some of the variety of production activities common to CBM extraction. These production activities include... methane migration through conduits created by drilling and fracturing practices..."

EPA Response: In response to stakeholder's comments on EPA's original study methodology, EPA compiled citizen complaints and reported incidences of CBM impacts on drinking water wells and included these accounts in Chapter 6 of the report. In the final report, EPA has clarified the rationale for including citizen complaints in its report.

The final report also clarifies that many of the reported impacts (such as impacts to water supply quantities and effects of discharge of groundwater extracted in the CBM production process) included in Chapter 6 are outside of the scope of SDWA and beyond the scope of the Phase I study. The goal of the Phase I study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into CBM wells, and to determine based on these findings if further study is warranted. EPA also incorporated information that was provided by states regarding incident reports, and state-specific regulations. Finally, the Agency took Table 6-2 out of the document because, as suggested by some commenters, summarizing citizen complaints in a tabular format oversimplified this information, and created a potential for misinterpretation. The information in Table 6-2 is presented in detail in the main body of Chapter 6.

See also EPA's response to comment in section II.D of this document regarding other issues pertaining to water contamination incidents and citizen complaints.

I. Other Chapter 7 Comments (Conclusions and Recommendations)

Summary of Comments: Most comments received regarding Chapter 7 of the report also relate back to prior report chapters. Several commenters had specific suggestions or questions regarding the conclusions and recommendations section of the report. Some of these commenters agreed with the conclusions of the study, but recommended that EPA put more emphasis on the conclusions, and include information about the findings of the study earlier in the document. Specifically, commenters suggested that, at the beginning of the document, EPA include a statement clarifying that: "EPA finds no evidence of harm from hydraulic fracturing while investigating the reported incidents that spurred the study." These commenters felt that EPA's findings that Phase II of the study is unnecessary, and that little or no public health threat is posed by hydraulic fracturing should be more strongly stated in the conclusions of the report.

Note that commenter opinions regarding Chapter 7 of the report do not reflect the overall commenter perspectives regarding the outcome and conclusions of the study. Most of the commenters expressed opinions regarding the study's conclusions, but did not state them within the context of Chapter 7.

EPA Response: EPA has reviewed all commenter suggestions regarding Chapter 7, and incorporated the majority of these comments where appropriate. Other revisions to Chapter 7, which relate back to changes in previous chapters, have been made in order to ensure internal consistency within the document.

VIII. BASIN DESCRIPTIONS

This summary of basin-specific comments focuses mainly on those comments that have not been summarized within the issue-specific Sections II through VI of this document. Many comments were received that provided minor editorial suggestions and factual corrections regarding basin descriptions. The Agency has considered all comments, researched the accuracy of some comments (where necessary), and incorporated public comments where appropriate.

A. San Juan Basin

Summary of Comments: One commenter provided suggested edits and corrections pertaining to the San Juan Basin geology, hydrology and USDW identification, and CBM production activity. This commenter also provided additional references.

EPA Response: EPA reviewed and considered all suggested edits and corrections and has incorporated revisions to the San Juan Basin descriptions. EPA also reviewed the additional references provided by the commenter, and incorporated additional pertinent information.

B. Black Warrior Basin

Summary of Comments: One commenter provided a variety of editorial comments and factual clarifications regarding the Black Warrior Basin. Examples of information the commenter questioned include: coal thickness; total dissolved solids levels; number of active Class II wells in this area; fracture height vs. length; and chemical components of fracturing fluids.

EPA Response: EPA has incorporated into the final report the majority of the commenter's suggestions regarding the description of the Black Warrior Basin.

C. Piceance Basin

Summary of Comments: One commenter provided a brief description of the activities and progress of the pilot program in the White River Dome field.

EPA Response: The final report contains the information provided by the commenter.

D. Uinta Basin

Summary of Comments: One commenter indicated that the information on the Castlegate Field is out of date. The commenter clarified that the field is currently in production, and explained why he believes that cross-contamination from the Blackhawk to the Castlegate Sandstone and Star Point Sandstone (as indicated in the report) is unlikely.

EPA Response: EPA has made revisions to the basin description based on this information.

E. Powder River Basin

Summary of Comments: *No substantive comments were submitted on this section.*

F. Central Appalachian Basin

Summary of Comments: One commenter provided clarifications and corrections regarding CBM activity, regulations, and drinking water sources in Virginia.

EPA Response: EPA has incorporated many of the commenter's clarifications into the basin description.

G. Northern Appalachian Basin

Summary of Comments: One commenter provided information on the square mileage and number of CBM wells in this basin, with associated references. This commenter, who is the individual that was interviewed for some of the information provided in this attachment, provided edits to the interview summary. Another commenter suggested several editorial corrections pertaining to the location of specific coal groups, the use of the term "group," and the use of the term "separated laterally" vs. "vertical separation."

EPA Response: EPA has incorporated all appropriate information into the basin description.

H. Western Interior Basin

Summary of Comments: This commenter questioned the accuracy of the statement that "coal seams could be coincident with a USDW" within the Cherokee Basin. The commenter discussed the aerial extent to which various coal seams in the Cherokee Basin coincide with USDWs, and recommended that EPA also review a 1997 paper entitled "Kansas coal resources and their potential for coalbed methane."

EPA Response: EPA has modified the report to indicate that "all or part of targeted coal seams could be coincident with a USDW," thereby clarifying the summary of the data provided in Table A8-2, which presents the relative depths of coal seams and USDWs.

I. Raton Basin

Summary of Comments: *No comments were submitted on this section.*

J. Sand Wash Basin

Summary of Comments: One commenter pointed out that in the Sand Wash Basin, the pilot at Craig Dome was abandoned "due to excessive water production." This commenter also believed that EPA's findings that hydraulic fracturing poses very little potential threat to USDWs does not account for proximity or overlap with natural fault lines. The commenter stated that: "if a fracture propagates into and along a fault plane, it may contaminate a USDW."

EPA Response: EPA has incorporated the commenter's information into Attachment 10 of the final report.

K. Washington Coal Regions (Pacific and Central)

Summary of Comments: *No comments were submitted on this section.*

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This master reference list pertains only to Chapters 1 through 7 of this document. Separate reference lists are provided for each appendix and attachment, and are provided at the end of each of these sections.

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Appendix A
Department of Energy - Hydraulic Fracturing White Paper

1.0 Introduction

The first hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in the Hugoton field.[1] The Kelpper Well No. 1, located in Grant County, Kansas was a low productivity well, even though it had been acidized. The well was chosen for the first hydraulic fracture stimulation treatment so that hydraulic fracturing could be compared directly to acidizing. Since that first treatment in 1947, hydraulic fracturing has become a standard treatment for stimulating the productivity of oil and gas wells.

Hydraulic fracturing is the process of pumping a fluid into a wellbore at an injection rate that is too high for the formation to accept in a radial flow pattern. As the resistance to flow in the formation increases, the pressure in the wellbore increases to a value that exceeds the breakdown pressure of the formation that is open to the wellbore. Once the formation “breaks-down”, a crack or fracture is formed, and the injected fluid begins moving down the fracture. In most formations, a single, vertical fracture is created that propagates in two directions from the wellbore. These fracture “wings” are 180^{o} apart, and are normally assumed to be identical in shape and size at any point in time. In naturally fractured or cleated formations, such as gas shales or coal seams, it is possible that multiple fractures can be created and propagated during a hydraulic fracture treatment.

Fluid that does not contain any propping agent, often called “pad”, is injected to create a fracture that grows up, out and down, and creates a fracture that is wide enough to accept a propping agent. The purpose of the propping agent is to “prop open” the fracture once the pumping operation ceases, the pressure in the fracture decreases, and the fracture closes. In deep reservoirs, we use man-made ceramic beads to prop open the fracture. In shallow reservoirs, sand is normally used as the propping agent. The sand used as a propping agent in shallow reservoirs, such as coal seams, is mined from certain quarries in the United States. The silica sand is a natural product and will not lead to any environmental concerns that would affect the United States Drinking Water (USDW).

The purposes of this paper are (1) to discuss the processes an engineer uses to design and pump a hydraulic fracture treatment, and (2) to provide an overview of the theories, design methods and materials used in a hydraulic fracture treatment. Currently, a discussion is taking place on the effects of hydraulic fracturing in coal seams on the USDW. Gas production from coal seams is increasing in importance in the United States. In 2000, over 6% of the natural gas production in the US was produced from coal seams, and that percentage will increase in the future. Because of the ever-increasing importance of natural gas production from coal seams, coal seam examples have been included in this technical paper.

<u>Objectives of Hydraulic Fracturing</u>

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well, or the injectivity index of an injection well. The productivity index defines the volumes of oil or gas that can be produced at a given pressure differential between the reservoir and the well bore. The injectivity index refers to how much fluid can be injected into an injection well at a given pressure differential.

There are many different applications for hydraulic fracturing, such as:

- Increase the flow rate of oil and/or gas from low permeability reservoirs,
- Increase the flow rate of oil and/or gas from wells that have been damaged,
- Connect the natural fractures and/or cleats in a formation to the wellbore,
- Decrease the pressure drop around the well to minimize sand production,
- Decrease the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition,
- Increase the area of drainage or the amount of formation in contact with the wellbore, and
- Connect the full vertical extent of a reservoir to a slanted or horizontal well.

Obviously, there could be other uses of hydraulic fracturing, but the majority of the treatments are pumped for these seven reasons.

A low permeability reservoir is one that has a high resistance to fluid flow. In many formations, chemical and/or physical processes alter a reservoir rock over geologic time. Sometimes, these diagenetic processes restrict the openings in the rock and reduce the ability of fluids to flow through the rock. Low permeability rocks are normally excellent candidates for stimulation by hydraulic fracturing.

Regardless of the permeability, a reservoir rock can be damaged when a well is drilled through the reservoir and when casing is set and cemented in place. Damage occurs because drilling and/or completion fluids leak into the reservoir and plug up the pores and pore throats. When the pores are plugged, the permeability is reduced, and the fluid flow in this damaged portion of the reservoir may be substantially reduced. Damage can be severe in naturally fractured reservoirs, like coal seams. To stimulate damaged reservoirs, a short, conductive hydraulic fracture is often the desired solution. As such, hydraulic fracturing works very well in many damaged, coal seam reservoirs.

In many cases, especially for low permeability formations, damaged reservoirs and horizontal wells in a layered reservoir, the well would be “uneconomic” unless a successful hydraulic fracture treatment is designed and pumped. Thus, the engineer in charge of the economic success of such a well, must (1) design the optimal fracture treatment, and then (2) go to the field to be certain the optimal treatment is pumped successfully.

Candidate Selection

The success or failure of a hydraulic fracture treatment often depends on the quality of the candidate well selected for the treatment. Choosing an excellent candidate for stimulation often ensures success, while choosing a poor candidate will normally result in economic failure. To select the best candidate for stimulation, the design engineer must consider many variables. The most critical parameters for hydraulic fracturing are formation permeability, the *in-situ* stress distribution, reservoir fluid viscosity, skin factor, reservoir pressure, reservoir depth and the condition of the wellbore. The skin factor refers to whether the reservoir is already stimulated or, perhaps is damaged. If the skin factor is positive, the reservoir is damaged and could possibly be an excellent candidate for stimulation.

The best candidate wells for hydraulic fracturing treatments will have a substantial volume of oil and gas in place, and will have a need to increase the productivity index. Such reservoirs will have (1) a thick pay zone, (2) medium to high pressure, (3) *in-situ* stress barriers to minimize vertical height growth, and (4) either be a low permeability zone or a zone that has been damaged (high skin factor). For coalbed methane reservoirs, the ideal candidate, in addition to the 4 factors listed above, will be a thick coal seam containing both (1) a large volume of sorbed gas and (2) abundant coal cleats to provide permeability.

Reservoirs that are not good candidates for hydraulic fracturing are those with little oil or gas in place due to thin reservoirs, low reservoir pressure, or small aerial extent. Reservoirs with extremely low permeability may not produce enough hydrocarbons to pay all the drilling and completion costs even if successfully stimulated; thus, such reservoirs would not be good candidates for stimulation. In coal seam reservoirs, the number, thickness and location of the coal seams must be considered when deciding if the coals can be completed and stimulated economically. If the coal seams are too thin or too scattered up and down the hole, the coals may not be ideal candidates for stimulation by hydraulic fracturing.

Developing Data Sets

For most petroleum engineering problems, developing a complete and accurate data set is often the most time consuming part of solving the problem. For hydraulic fracture treatment design, the data required to run both the fracture design model and the reservoir simulation model can be divided into two groups. One group lists the data that can be "controlled" by the engineer. The second group reflects data that must be measured or estimated, but cannot be controlled.

The primary data that can be controlled by the engineer are the well completion details, treatment volume, pad volume, injection rate, fracture fluid viscosity, fracture fluid density, fluid loss additives, propping agent type, and propping agent volume. The data that must be measured or estimated by the design engineer are formation depth, formation permeability, *in-situ* stresses in the pay zone, *in-situ* stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of the reservoir. There are actually three (3) thickness that are important to the design engineer: the gross thickness of the reservoir; the net thickness of the oil or gas producing interval; and the permeable thickness that will accept fluid loss during the hydraulic fracture treatment.

The most critical data for the design of a fracture treatment are, roughly in order of importance, (1) the *in-situ* stress profile, (2) formation permeability, (3) fluid loss characteristics, (4) total fluid volume pumped, (5) propping agent type and amount, (6) pad volume, (7) fracture fluid viscosity, (8) injection rate, and (9) formation modulus. Since most engineers have more work to do than time to do the work, the design engineer should focus most of his/her time on the most important parameters. In hydraulic fracture treatment design, by far, the two most important parameters are the *in-situ* stress profile and the permeability profile of the zone to be stimulated and the layers of rock above and below the target zone.

In new fields or reservoirs, most operating companies are normally willing to spend money to run logs, cut cores and run well tests to determine important factors such as the *in-situ* stress and the permeability of the major reservoir layers. By using such data, along with fracture treatment records and production records, accurate data sets for a given reservoir in a given field can normally be compiled. These data sets can be used on subsequent wells to optimize the fracture treatment designs. It is normally not practical to cut cores and run well tests on every well. Thus, the data obtained from cores and well tests must be correlated to log parameters so the logs on subsequent wells can be used to compile accurate data sets.

To design a fracture treatment, most engineers use pseudo 3-dimensional (P3D) models. Full 3-D models exist; however, the use of full 3-D models is currently limited to supercomputers and research organizations. To use a P3D model, the data must be input by reservoir layer. Fig. 1 illustrates the profiles of important input data required by a P3D model. For the situation in

Fig. 1, the fracture treatment would be initiated in the sandstone reservoir. The fracture would typically grow up and down until a barrier is reached to prevent vertical fracture growth. In many cases, thick marine shale will be a barrier to vertical fracture growth. In some cases, coal seams will prevent fractures from growing vertically. Many coal seams are highly cleated, and when the fracture fluid enters the coal seam, it remains contained within the coal seam. In thick, highly cleated coal seams, the growth of the hydraulic fracture will normally be limited to the coal seam.

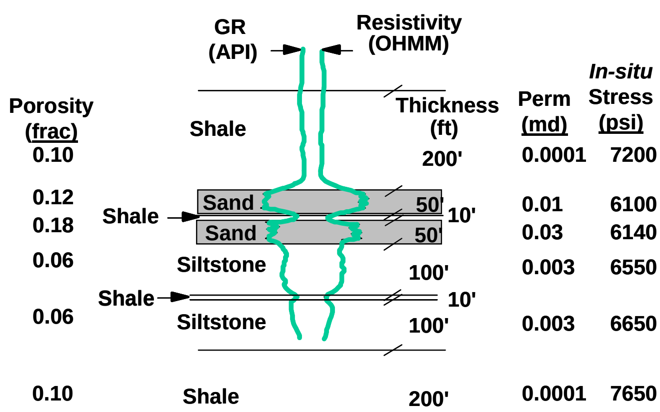


Fig. 1 – Typical input data for a P3D model.

The data used to design a fracture treatment can be obtained from a number of sources, such as drilling records, completion records, well files, open hole geophysical logs, cores and core analyses, well tests, production data, geologic records, and other public records, such as publications. In addition, service companies provide data on their fluids, additives and propping agents. Table 1 illustrates typical data needed to design a fracture treatment and possible sources for the data.

Fracture Treatment Optimization

The goal of every design engineer should be to design the optimum fracture treatment for each and every well. In 1978, Holditch *et al.*[2] wrote a paper concerning the optimization of both the

Table 1 – Sources of Data

Data	Units	Sources
Formation Permeability	md	Cores, Well Tests, Correlations, Production Data
Formation Porosity	%	Cores, Logs
Reservoir Pressure	psi	Well Tests, Well Files, Regional Data
Formation Modulus	psi	Cores, Logs, Correlations
Formation Compressibility	psi	Cores, Logs, Correlations
Poisson's Ratio		Cores, Logs, Correlations
Formation Depth	ft	Logs, Drilling Records
In-situ Stress	psi	Well Tests, Logs, Correlations
Formation Temperature	°F	Logs, Well Tests, Correlations
Fracture Toughness	psi - $\sqrt{in}$	Cores, Correlations
Water Saturation	%	Logs, Cores
Net Pay Thickness	Ft	Logs, Cores
Gross Pay Thickness	Ft	Logs, Cores, Drilling Records
Formation Lithology		Cores, Drilling Records, Logs, Geologic Records
Wellbore Completion		Well Files, Completion Prognosis
Fracture Fluids		Service Company Information
Fracture Proppants		Service Company Information

propped fracture length and the drainage area (well spacing) for low permeability gas reservoirs. Fig. 2 illustrates the methodology used to optimize the size of a fracture treatment [3,4]. Fig. 2 clearly shows the following:

- As the propped length of a fracture increases, the cumulative production will increase, and the revenue from hydrocarbon sales will increase,
- As the fracture length increases, the incremental benefit ($ of revenue per foot of additional propped fracture length) decreases,
- As the treatment volume increases, the propped fracture length increases,
- As the fracture length increases, the incremental cost of each foot of fracture ($ of cost per foot of additional propped fracture length) increases, and

- When the incremental cost of the treatment is compared to the incremental benefit of increasing the treatment volume, an optimum propped fracture length can be found for every situation.

Additional economic calculations can be made to determine the optimum fracture treatment design. However, in all cases, the design engineer must consider the effect of the fracture upon flow rates and recovery, the cost of the treatment, and the investment guidelines of the operator of the well.

Field Considerations

After the optimum fracture treatment has been designed, it must be pumped into the well successfully. A successful field operations requires planning, coordination and cooperation of all parties. Treatment supervision and the use of quality control measures will improve the successful application of hydraulic fracturing. Safety is always the primary concern in the field. Safety begins with a thorough understanding by all parties on their duties in the field. A safety meeting is always held to review the treatment procedure, establish a chain of command, be sure everyone knows his/her job responsibilities for the day, and to establish a plan for emergencies. The safety meeting should also be used to discuss the well completion details and the maximum allowing injection rate and pressures, as well as the maximum pressures to be held as backup to an annulus. All casing, tubing, wellheads, valves, and weak links, such as liner tops, should be thoroughly tested prior to rigging up the fracturing equipment. Mechanical failures during a treatment can be costly and dangerous. All mechanical problems should be repaired prior to pumping the fracture treatment.

Prior to pumping the treatment, the engineer-in-charge should conduct a detailed inventory of all the equipment and materials on location. The inventory should be compared to the design and the prognosis. After the treatment has concluded, the engineer should conduct another inventory of all the materials left on location. In most cases, the difference in the two inventories can be used to verify what was mixed and pumped into the wellbore and the hydrocarbon bearing formation.

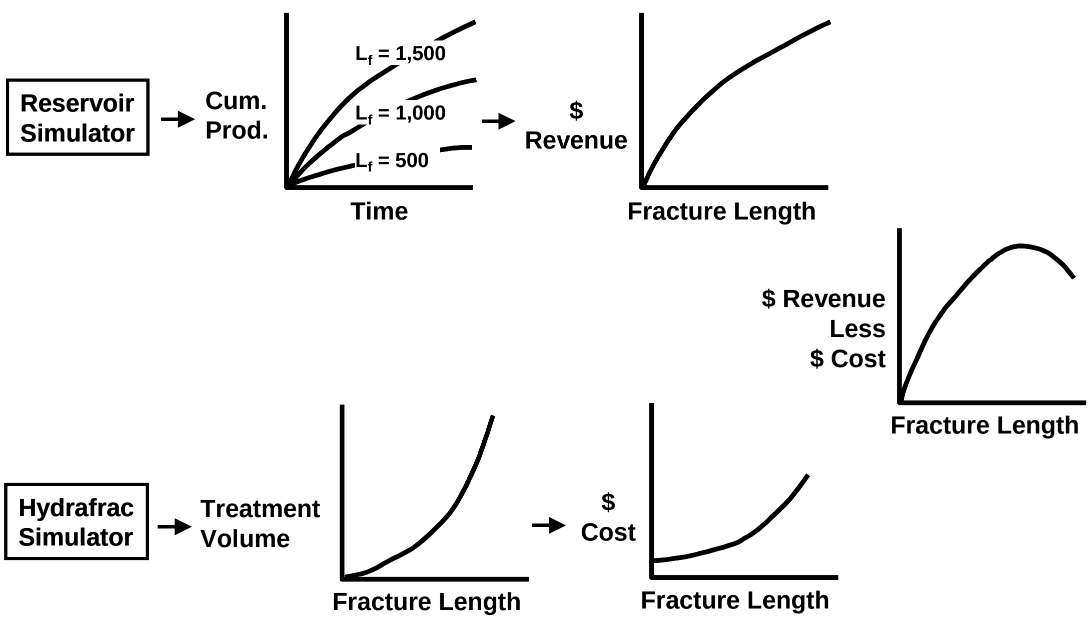


Fig. 2 – Fracture treatment optimization process.

In addition to an inventory, samples of the base fracturing fluid (usually water) should be taken and analyzed. Typically, a water analysis is done on the base fluid to determine the minerals present and the type of bacteria in the water. The data from the water analysis can be used to select the additives required to mix the viscous fracture fluid required to create a wide fracture and to transport the propping agent into the fracture. Table 2 shows the typical compositions for mix waters used in different fracturing situations. In addition to testing the water, samples of the additives used during a treatment and the fracture fluid after all additives have been added should be taken during the job and saved for future analyses, if required.

Table 2 – Fracturing Fluids and Conditions for Their Use

Base Fluid	Fluid Type	Main Composition	Used For
Water Based	Linear Fluids	Gelled Water, GUAR< HPG, HEC, CMHPG	Short Fractures, Low Temperatures
	Crosslinked Fluids	Crosslinker + GUAR, HPG, CMHPG, CMHEC	Long Fractures, High Temperatures
Foam Based	Water Based Foam	Water and Foamer + N_2 or CO_2	Low Pressure Formations
	Acid Based Foam	Acid and Foamer + N_2	Low Pressures, Water Sensitive Formations
	Alcohol Based Foam	Methanol and Foamer + N_2	Low Pressure Formations With Water Blocking Problems
Oil Based	Linear Fluids	Oil, Gelled Oil	Water Sensitive Formations, Short Fractures
	Crosslinked Fluids	Phosphate Ester Gels	Water Sensitive Formations, Long Fractures
	Water External Emulsions	Water + Oil + Emulsifier	Good For Fluid Loss Control

Formation temperature is one of the main factors concerning the type of additives required to mix the optimum fracturing fluid. In deep, hot reservoirs (>250^{o}F), more additives are required than in shallow, low temperature reservoirs. Since most coal seams are very shallow, fewer additives are normally required to mix the optimum fracture fluid.

2.0 Fracture Mechanics

Fracture mechanics has been part of mining engineering and mechanical engineering for hundreds of years. No one is more interested in underground rock fractures than a miner working in an underground mine. In petroleum engineering, we have only used fracture mechanics theories in our work for about 50 years. Much of what we use in hydraulic fracturing theory and design has been developed by other engineering disciplines many years ago. However, certain aspects, such as poroelastic theory, are unique to porous, permeable underground formations. The most important parameters are *in-situ* stress, Poisson's ration, and Young's modulus.

In-situ Stresses

Underground formations are confined and under stress. Fig. 3 illustrates the local stress state at depth for an element of formation. The stresses can be divided into 3 principal stresses. In Fig. 3, σ_1 is the vertical stress, σ_2 is the maximum horizontal stress, while σ_3 is the minimum horizontal stress, where $\sigma_1>\sigma_2>\sigma_3$. This is a typical configuration for coalbed methane reservoirs. However, depending on geologic conditions, the vertical stress could also be the intermediate (σ_2) or minimum stress (σ_3). These stresses are normally compressive and vary in magnitude throughout the reservoir, particularly in the vertical direction (from layer to layer). The magnitude and direction of the principal stresses are important because they control the pressure required to create and propagate a fracture, the shape and vertical extent of the fracture, the direction of the fracture, and the stresses trying to crush and/or embed the propping agent during production.

A hydraulic fracture will propagate perpendicular to the minimum principal stress (σ_3). If the minimum horizontal stress is σ_3, the fracture will be vertical and, we can compute the minimum horizontal stress profile with depth using Eq. 1.

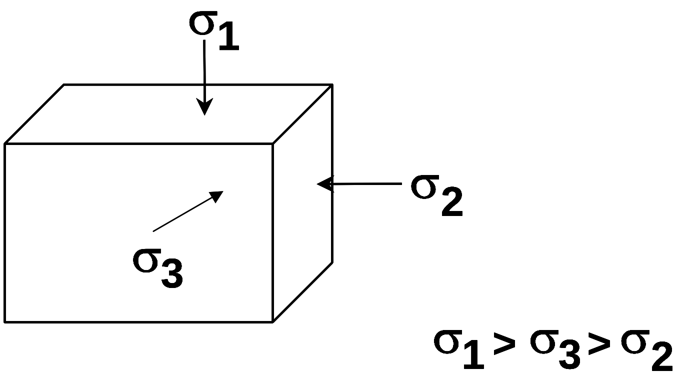


Fig. 3 – Local in-situ stress at depth.

$$\sigma_{min} \cong \frac{\nu}{1-\nu}\left(\sigma_{ob} - \alpha\,\sigma_p\right) + \alpha\,\sigma_p + \sigma_{ext} \qquad \text{Eq. 1}$$

Where:

σ_{min}	=	the minimum horizontal stress (*in-situ* stress)
ν	=	Poissons' ratio
σ_{ob}	=	overburden stress
α	=	Biot's constant
σ_p	=	reservoir fluid pressure or pore pressure
σ_{ext}	=	tectonic stress

Poisson's ratio can be estimated from acoustic log data or from correlations based upon lithology. For coal seams, the value of Poisson's ratio will range from 0.2 – 0.4. The overburden stress can be computed using density log data. Normally, the value for overburden pressure is about 1.1 psi per foot of depth. The reservoir pressure must be measured or estimated. Biot's constant must be less than or equal to 1.0 and typically ranges from 0.5 to 1.0. The first two (2) terms on the right hand side of Eq.1 represent the horizontal stress resulting from the vertical stress and the poroelastic behavior of the formation. The tectonic stress term is important in many areas where plate tectonics or other forces increase the horizontal stresses.

Poroelastic theory can be used to determine the minimum horizontal stress in tectonically relaxed areas.[8,9] Poroelastic theory combines the equations of linear elastic stress-strain theory for solids with a term that includes the effects of fluid pressure in the pore space of the reservoir rocks. The fluid pressure acts equally in all directions as a stress on the formation material. The "effective stress" on the rock grains is computed using linear elastic stress-strain theory. Combining the two sources of stress results in the total stress on the formation, which is the stress that must be exceeded to initiate fracturing.

In many areas, however, the effects of tectonic activity must be included in the analyses of the total stresses. To measure the tectonic stresses, injection tests are conducted to measure the minimum horizontal stress. The measured stress is then compared to the stress calculated by the poroelastic equation to determine the value of the tectonic contribution.

Basic Rock Mechanics

In addition to the *in-situ* or minimum horizontal stress, other rock mechanical properties are important when designing a hydraulic fracture. Poisson's ratio is defined as "the ratio of lateral expansion to longitudinal contraction for a rock under a uniaxial stress condition".[10] The value of Poisson's ratio is used in Eq. 1 to convert the effective vertical stress component into an effective horizontal stress component. The effective stress is defined as the total stress minus the pore pressure.

The theory used to compute fracture dimensions is based upon linear elasticity. To apply this theory, the modulus of the formation is an important parameter. Young's modulus is defined as "the ratio of stress to strain for uniaxial stress".[10] The modulus of a material is a measure of the stiffness of the material. If the modulus is large, the material is stiff. In hydraulic fracturing, a stiff rock will result in more narrow fractures. If the modulus is low, the fractures will be wider. The modulus of a rock will be a function of the lithology, porosity, fluid type, and other variables. Table 3 illustrates typical ranges for modulus as a function of lithology.

Table 3. Typical Ranges of Young's Modulus for Various Lithologies

Lithology	Young's Modulus
Soft Sandstone	2-5 x 10^6 psi
Hard Sandstone	6-10 x 10^6 psi
Limestone	8-12 x 10^6 psi
Coal	0.1-1 x 10^6 psi
Shale	1-10 x 10^6 psi

Because coal is highly cleated, the modulus of the coal seam *in-situ* may be very low. In very low modulus, highly cleated coal seams, it is likely that most fractures will be wide and short, that is, not penetrating far into the formation from the well bore.

Fracture Orientation

A hydraulic fracture will propagate perpendicular to the least principle stress (Fig. 3). In some shallow formations the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. Nielsen and Hansen published a paper where horizontal fractures in coal seam reservoirs were documented [11]. In reservoirs deeper than 1000 ft or so, the least principal stress will likely be horizontal; thus, the hydraulic fracture will be vertical. The azimuth orientation of the vertical fracture will depend upon the azimuth of the minimum and maximum horizontal stresses. Lacy and Smith provided a detailed discussion of fracture azimuth in SPE Monograph 12.[12]

Injection Tests

The only reliable technique for measuring *in-situ* stress is by pumping into a reservoir, creating a fracture, and measuring the pressure at which the fracture closes [13]. The well tests used to measure the minimum principal stress are as follows: *in-situ* stress tests; step-rate/flow back tests; mini-fracture tests; and step-down tests. For most fracture treatments, mini-fracture tests and step-down tests are pumped ahead of the main fracture treatment. As such, accurate data are normally available to calibrate and interpret the pressures measured during a fracture treatment. *In-situ* stress tests and step-rate/flow back tests are not run on every well. However, it is common to run such tests in new fields or new reservoirs to help develop the correlations required to optimize fracture treatments for subsequent wells.

An *in-situ* stress test (or micro-frac) can be either an injection-falloff test or an injection-flow back test. The *in-situ* stress test is conducted using small volumes of fluid (a few barrels), injected at low injection rates (gals/min), normally using straddle packers to minimize well bore storage effects, into a small number of perforations (1-2 ft). The objective is to pump a thin fluid (water or nitrogen) at a rate barely sufficient to create a small fracture. Once the fracture is open, then the pumps are shut down, and the pressure is recorded and analyzed to determine when the fracture closes. Thus, fracture closure pressure is synonymous with *in-situ* stress and with minimum horizontal stress. When the pressure in the fracture is greater than the fracture closure pressure, the fracture is open. When the pressure in the fracture decreases below the fracture closure pressure, the fracture is closed. Fig. 4 illustrates a typical wellbore configuration for conducting an *in-situ* stress test. Fig. 5 shows typical data that are measured. Multiple tests are conducted to ensure repeatability. The data from any one of the injection-falloff tests can be analyzed to determine when the fracture closes.

Fig. 6 illustrates how one such test can be analyzed to determine *in-situ* stress.

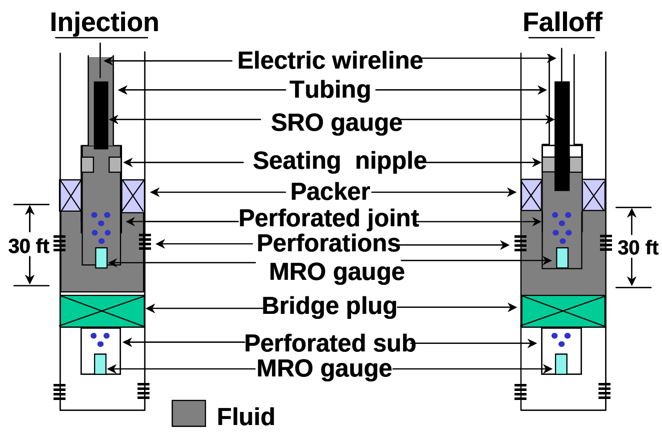


Fig. 4 – Cased hole test configuration.

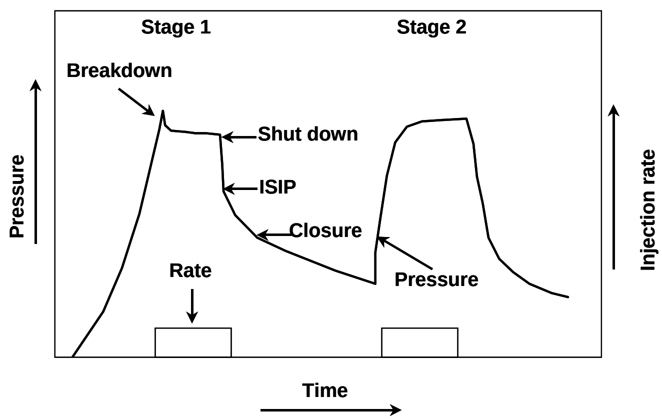


Fig. 5 – Typical stress test pump-in/shut-in.

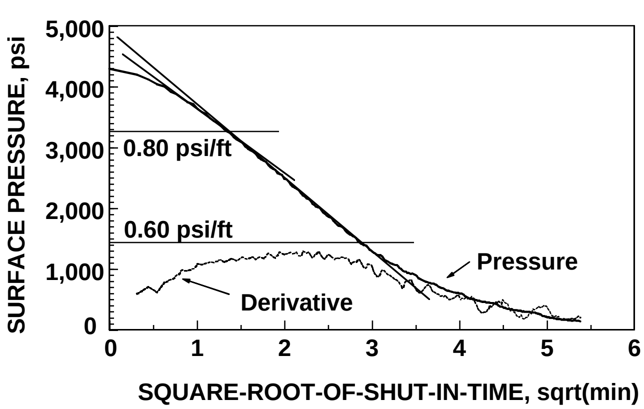


Fig. 6 – Closure pressure analysis.

Mini-fracture tests are run to reconfirm the value of *in-situ* stress in the pay zone and to estimate the fluid loss properties of the fracture fluid. A mini-fracture test is run using fluid similar to the fracture fluid that will be used in the main treatment. Several hundred barrels of fracturing fluid are normally pumped at fracturing rates. In coal seams, because the fracture height will usually be small, the mini-fracture test will often be eliminated or pumped with only a small volume of fracturing fluid. The purpose of the injection is to create a fracture that will be of similar height to the one created in the main fracture treatment. After the mini-fracture has been created, the pumps are shut down and the pressure decline is monitored. The pressure decline can be used to estimate the fracture closure pressure and the total fluid leak-off coefficient. Data from mini-fracture treatments can be used to alter the design of the main fracture treatment if the data determined during the mini-fracture test is substantially different that the data used to design the main fracture treatment.

For an injection-falloff test to be conducted successfully, it is necessary to have a clean connection between the wellbore and the created fracture. The purpose of *in-situ* stress tests and mini-fracture tests are to determine the pressure in the fracture when the fracture is open, and the pressure when the fracture is closed. If there is excess pressure drop near the wellbore, due to poor connectivity between the wellbore and the fracture, the interpretation of *in-situ* stress test data can be difficult. In coal seam reservoirs, due to the highly cleated nature of the coal, multiple fractures that follow tortuous paths are often created during injection tests.[14] When these tortuous paths are created, the pressure drop in the "near-wellbore" region can be very high, which complicates the analyses of the pressure falloff data. As such, *in-situ* stress test data and data from mini-fracture tests in coal seams are very difficult to measure and interpret.

The design engineer needs data from well tests to design the optimum fracture treatment. It is common for an operator to spend a lot of money and time running injection tests to determine values of *in-situ* stress, formation permeability, and leak-off coefficient. Fracture treatment theory is well grounded in science and engineering and, in most cases, data are collected from logs, cores and well tests to assure that designs are as accurate as possible.

3. Fracture Propagation Models

The first fracture treatments were pumped just to see if a fracture could be created and if sand could be pumped into the fracture. In 1955, Howard and Fast[15] published the first mathematical model that an engineer could use to design a fracture treatment. The Howard and Fast model assumed the fracture width was constant everywhere, allowing the engineer to compute fracture area based upon fracture fluid leakoff characteristics of the formation and the fracturing fluid.

2D Fracture Propagation Models

The Howard and Fast model was a two-dimensional (2D) model. In the following years, other 2D models were published.[16-19] When using a 2D model, the engineer fixes one of the dimensions (normally the fracture height), then calculates the width and length of the fracture. With experience and accurate data sets, 2D models can be used with confidence because the design engineer can accurately estimate the created fracture height beforehand.

Figs. 7 and 8 illustrate two of the most common 2D models used in fracture treatment design. The PKN geometry (Fig. 7) is normally used when the fracture length is much greater than the fracture height, while the KGD geometry (Fig. 8) is used if fracture height and length are similar [20]. Either of these two models can be used successfully to design hydraulic fractures. The key is to use models to make decisions. The design engineer must always compare actual results with the predictions from model calculations. By "calibrating" the 2D model with field results, the 2D models can be used to make design changes and improve the success of stimulation treatments.

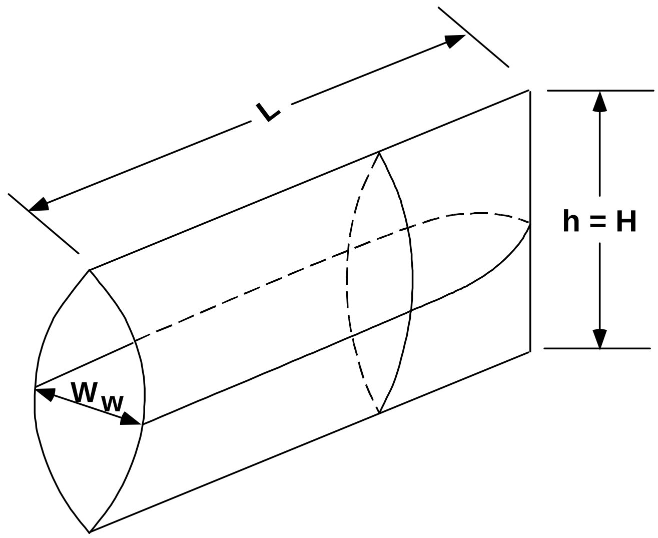


Fig. 7 – PKN geometry.

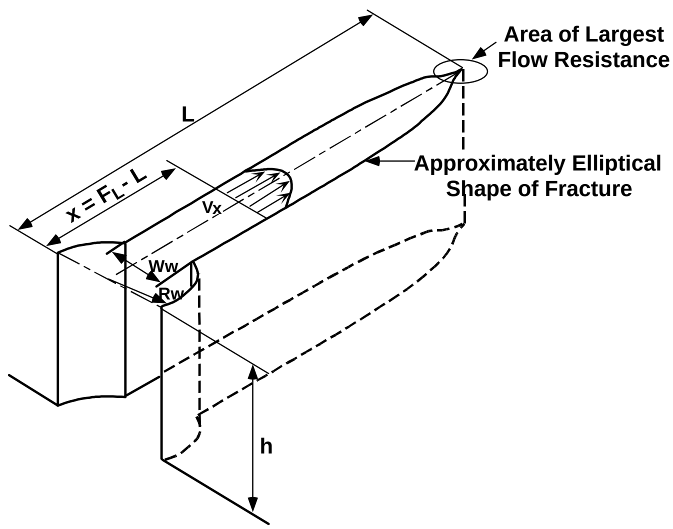


Fig. 8 – KGD geometry.

If the correct value of fracture height is used in a 2D model, the model will give reasonable estimates of created fracture length and width, provided, of course, that other parameters, such as *in-situ* stress, Young's modulus, formation permeability and total leakoff coefficient are also entered correctly. Engineers had to use 2D models for years due to the lack of computing power. Today, with high-powered computers available to most engineers, Pseudo 3-Dimensional (P3D) models are used by most fracture design engineers. P3D models are better than 2D models for most situations because the P3D model computes the fracture height, width and length distribution using the data for the pay zone and all the rock layers above and below the perforated interval.

<u>*3D Fracture Propagation Models*</u>

Clifton[21] provides a detailed explanation of how 3-Dimensional fracture propagation theory is used to derive equations for programming 3D models, as well as P3D models. Figs. 9 and 10 illustrate typical results from a P3D model. P3D models give more realistic estimates of fracture geometry and dimensions, which can lead to better designs and better wells. P3D models are used to compute the shape of the hydraulic fracture as well as the dimensions.

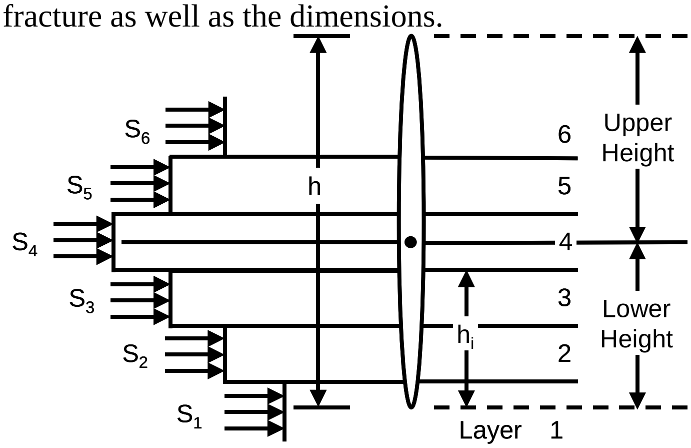


Fig. 9 – Width from a P3D model.

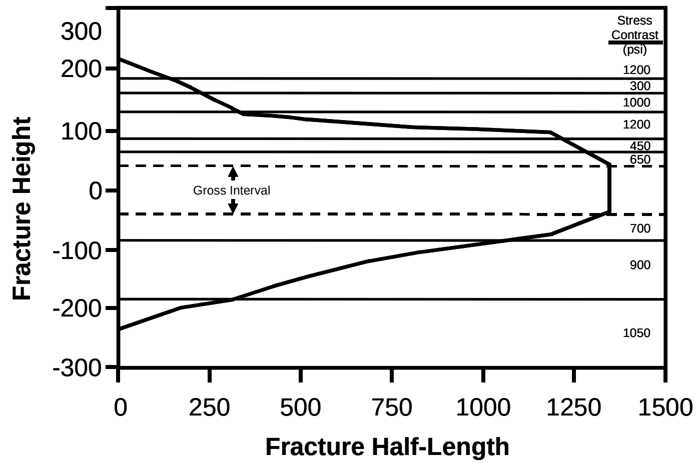


Fig. 10 – Width and height from P3D model.

4. Fracturing Fluids and Additives

To create the fracture, a fluid is pumped into the wellbore at high rate to increase the pressure in the wellbore at the perforations to a value greater than the breakdown pressure of the formation. The breakdown pressure is generally believed to be the sum of the *in-situ* stress and the tensile strength of the rock. Once the formation is broken down, and the fracture is created, then the fracture can be propagated at a pressure called the fracture propagation pressure. The fracture propagation pressure is equal to the sum of the *in-situ* stress, plus the net pressure drop, plus the near wellbore pressure drop. The net pressure drop is equal to the pressure drop down the fracture due to viscous fluid flow in the fracture. The near wellbore pressure drop can be a combination of the pressure drop of the viscous fluid flowing through the perforations and/or the pressure drop due to tortuosity between the wellbore and the propagating fracture. Thus, the fracturing fluid properties are very important in the creation and propagation of the fracture.

<u>Properties of a Fracturing Fluid</u>

The ideal fracturing fluid should be compatible with the formation rock, compatible with the formation fluid, generate enough pressure drop down the fracture to create a wide fracture, be able to transport the propping agent in the fracture, break back to a low viscosity fluid for clean up after the treatment, and be cost effective. The family of fracture fluids available consist of water base fluids, oil base fluids, acid base fluids and foam fluids. Table 2 lists the types of fracturing fluids that are available and the general use of each type of fluid. For most reservoirs, water base fluids with appropriate additives will be the best fluid. In some cases, foam generated using N_2 or CO_2 can be used to successfully stimulate shallow, low-pressure zones. When water is used as the base fluid, the water should be tested for quality. Table 4 presents generally accepted levels of water quality for use in hydraulic fracturing.

Table 4 - Acceptable Levels for Mix Water

pH	6-8
Iron	< 10 ppm
Oxidizing Agents	None
Reducing Agents	None
Carbonate*	< 300 ppm
Bicarbonate*	< 300 ppm
Bacteria	None
Cleanliness	Reasonable
*Higher Carbonate/Bicarbonate Content Will Require Further Pilot Testing on Gel Break, and Crosslinking	

The viscosity of the fracture fluid is important. The fluid should be viscous enough (normally 50–1000 cp) to create a wide fracture (normally 0.2–1.0 in) and transport the propping agent into the fracture (normally 10s to 100s of feet). The density of the fluid is also important. Water based fluids have densities near 8.4 ppg. Oil base fluids, although never used to fracture treat coal seam reservoirs, will have densities that are 70-80% of the water based fluids. Foam fluids can have densities that are 50% or less those of water based fluids. The density affects the surface injection pressure and the ability of the fluid to flow back after the treatment. In low pressure reservoirs, low density fluids, like foam, can be used to assist in the fluid clean up.

A fundamental equation used in all fracture models is that the fracture volume is equal to the total volume of fluid injected minus the volume of fluid that leaks off into the reservoir. The fluid efficiency is the percentage of fluid that is still in the fracture at any point in time, when compared to the total volume injected at the same point in time. The concept of fluid loss was used by Howard and Fast to determine fracture area [15]. If too much fluid leaks off, the fluid has a low efficiency (say 10-20%) and the created fracture volume will be only a fraction of the total volume injected. However, if the fluid efficiency is too high (say 80-90%), the fracture will not close rapidly after the treatment. Ideally, a fluid efficiency between 40-60% will provide an optimum balance between creating the fracture and having the fracture close down after the treatment.

In most low permeability reservoirs, fracture fluid loss and efficiency is controlled by the formation permeability. In high permeability formations, a fluid-loss additive must be added to the fracture fluid to reduce leak-off and improve fluid efficiency. In highly cleated coal seams, the leak-off can be extremely high, with efficiencies down in the 10-20% range. To fracture treat these highly cleated coal seams, the treatment must often be pumped at high injection rates using fluid loss additives. In general, the objective of most fracture treatments in coal seams is to create a short, wide fracture to connect the coal cleat system to the well bore vs. creating long hydraulic fractures that penetrate deeply into the coal seam. Therefore, water with very few additives, pumped at medium to high injection rates is commonly used to stimulate coal seam reservoirs.

Fracture Fluid Additives

Typical additives for a fracture fluid have been described in detail by Ely [22]. Typical additives for a water based fluid are briefly described below.

- Polymers – used to viscosify the fluid
- Crosslinkers – used to change the viscous fluid to a pseudo-plastic fluid
- Biocides – used to kill bacteria in the mix water
- Buffers – used to control the pH of the fracture fluid
- Surfactants – used to lower the surface tension
- Fluid loss additives – used to minimize fluid leak-off into the formation
- Stabilizers – used to keep the fluid viscous at high temperature
- Breakers – used to break the polymers and crosslink sites at low temperature

Additional information on additives is presented in Table 5.

Table 5 – Summary of Chemical Additives

Type of Additive	Function Performed	Typical Products
Biocide	Kills bacteria	Gluteridehyde carbonate
Breaker	Reduces fluid viscosity	Acid, oxidizer, enzyme breaker
Buffer	Controls the pH	Sodium bicarb., fumaric acid
Clay stabilizer	Prevents clay swelling	KCl, NH CL, KCl substitutes
Diverting agent	Diverts flow of fluid	Ball sealers, rock salt, flake boric-acid
Fluid loss additive	Improves fluid efficiently	Diesel, particulates, fine sand
Friction reducer	Reduces the friction	Anionic copolymer
Iron Controller	Keeps iron in solution	Acetic & citric acid
Surfactant	Lowers surface tension	Fluorocarbon, Nonionic
Gel stabilizer	Reduces thermal degradation	MEOH, sodium thiosulphate

The owner of the oil or gas well normally does not own the equipment or the additives required to pump a fracture treatment. The operator will hire a service company to pump the fracture treatment. Each service company has their own research department for developing fracture fluids and additives. Each service company obtains their additives from various suppliers. As such, there is no set of rules one can use to select the proper additives for a fracture fluid, without first consulting with the service company that will mix and pump the fluid into the well. Many times, pilot tests of the fracture fluids must be conducted to be certain all the additives will work properly at the temperature in the reservoir and for the duration of the treatment.

All operating and service companies are concerned with protecting the environment and the USDW. As such, research is being conducted in developing "green additives" to use in hydraulic fracturing, especially in shallow formations like coal seam reservoirs. It costs a lot of money to handle additives and dispose of fracturing fluids that are either left over after the treatment or produced back from the well bore. The development of new, green additives will be a new technology that will benefit all parties.

5. Propping Agents and Fracture Conductivity

Propping agents are required to "prop-open" the fracture once the pumps are shut down and the fracture begins to close. The ideal propping agent will be strong, resistant to crushing, resistant to corrosion, have a low density, and readily available at low cost.[23] The products that best meet these desired traits are silica sand, resin-coated sand, and ceramic proppants.

Types of Propping Agents

Silica sand is obtained from sand mining operations. There are several sources in the

United States and a few outside the US. The sand must be tested to be sure it has the necessary compressive strength to be used in any specific situation. Generally, sand is used to prop open fractures in shallow formations. For coal seam reservoirs, sand is usually the best choice for a propping agent and virtually every fracture treatment in a coal seam reservoir uses sand. Sand is much less expensive per pound than the resin-coated sand or the ceramic proppants.

Resin-coated (epoxy) sand is stronger than sand and is used where more compressive strength is required to minimize proppant crushing. Some resins can be used to form a consolidated sand pack in the fracture, which will help to eliminate proppant flow back into the wellbore. Resin coated sand is more expensive than sand.

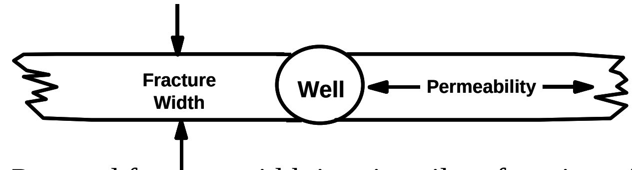
Ceramic proppants consist of sintered bauxite, intermediate strength proppant (ISP), and light weight proppant (LWP). The strength of the proppant is proportional to its density. Also, the higher strength proppants, like sintered bauxite, cost more than ISP and LWP. Ceramic proppants are used to stimulate deep (>8,000 ft) wells where large values of *in-situ* stresses will apply large forces on the propping agent.

Factors Affecting Fracture Conductivity

The fracture conductivity is the product of propped fracture width and the permeability of the propping agent, as illustrated in Fig. 11. The permeability of all the propping agents, sand, resin-coated sand, and the ceramic proppants, will be 200+ darcies when no stress has been applied to the propping agent. However, the conductivity of the fracture will be reduced during the life of the well because of increasing stress on the fracture, stress corrosion affecting the proppant strength, proppant crushing, proppant embedment into the formation, and damage due to gel residue or fluid loss additives.

- Fracture Conductivity, wk_f

  wk_f = fracture width x fracture permeability



- Propped fracture width is primarily a function of proppant concentration

Fig. 11 – Definition of fracture conductivity.

The effective stress on the propping agent is the difference between the *in-situ* stress and the flowing pressure in the fracture, as illustrated in Fig. 12. As the well is produced, the effective stress on the propping agent will normally increase because the value of the flowing bottom hole pressure will be decreasing. However, as can be seen by examining Eq. 1, the *in-situ* stress will decrease with time as the reservoir pressure declines. This phenomenon of decreasing *in*-situ stress as the reservoir pressure declines was proven conclusively by Salz.[8] In shallow coal seam reservoirs, the effective stress on the propping agent is always low and does not normally affect the fracture conductivity.

- **The stress on proppant (P_{eff}) increases as the flowing bottomhole pressure decreases**

$$\Delta P_{eff} = \sigma_{insitu} - P_{wf}$$

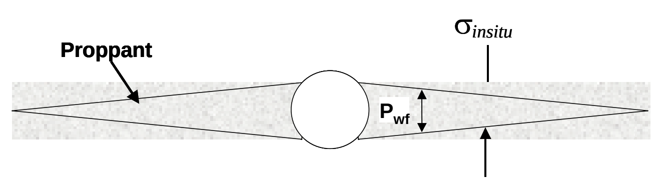


Fig. 12 – Effective stress on proppant.

Fig. 13 illustrates the differences is fracture conductivity vs. increasing effective stress on the propping agent for a variety of commonly used propping agents. The data in Fig. 13 clearly show that for shallow wells, where the effective stress is less than 4000 psi, sand can be used to create high conductivity fractures. As the effective stress increases to larger and larger values, then the higher strength, more expensive propping agents must be used to create a high conductivity fracture.

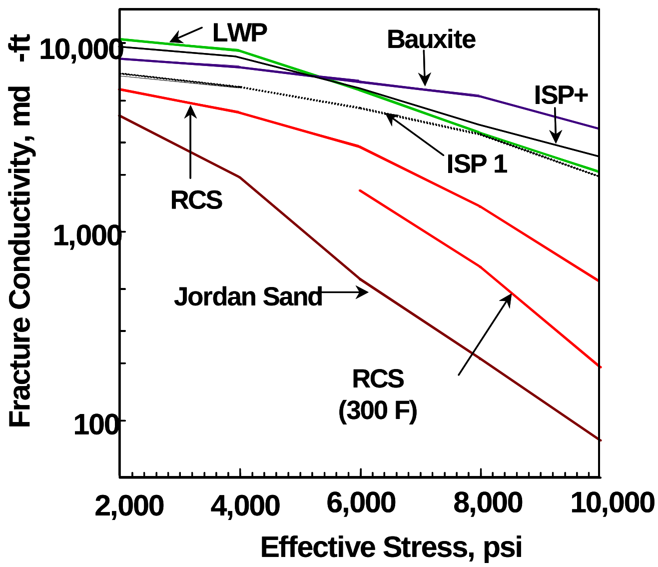


Fig. 13 – Effect of stress on conductivity.

6. Fracture Treatment Design

Data Requirements

In **Section 1** of this paper, the data required by the engineer to design a hydraulic fracture treatment was discussed. The data were divided into two groups: (1) data that must be measured or estimated and (2) data that can be controlled by the design engineer. The primary data that can be controlled by the engineer are the well completion details, treatment volume, pad volume, injection rate, fracture fluid viscosity, fracture fluid density, fluid loss additives, propping agent type, and propping agent volume.

As stated earlier, the most important data are (1) the *in-situ* stress profile, (2) formation permeability, (3) fluid loss characteristics, (4) total fluid volume pumped, (5) propping agent type and amount, (6) pad volume, (7) fracture fluid viscosity, (8) injection rate, and (9) formation modulus. The two most important parameters are the *in-situ* stress profile and the permeability profile of the zone to be stimulated and the layers of rock above and below the target zone.

There is a structured methodology followed by the engineer to design, optimize, execute, evaluate and re-optimize the fracture treatments in any reservoir. The first step is always the construction of a complete and accurate data set. Table 1 lists the sources for the data required to run fracture propagation and reservoir models. Notice that the design engineer must be capable of analyzing logs, cores, production data, well test data, and digging through well files to obtain all the information needed to design and evaluate a well that is hydraulically fracture treated.

Design Procedures

To design the optimum treatment, the engineer must determine the effect of fracture length and fracture conductivity upon the productivity and the ultimate recovery from the well. As in all engineering problems, sensitivity runs need to be made to evaluate uncertainties, such as formation permeability and drainage area. In coal seam reservoirs, uncertainties can also exist in variables such as the gas content and the desorption rate. The production data obtained from the reservoir model should be used in an economics model to determine the optimum fracture length and conductivity. Then a fracture treatment must be designed using a P3D fracture propagation model to achieve the desired length and conductivity at minimum cost. The most important concept is to design a fracture using all data and appropriate models that will result in the optimum economic benefit to the operator of the well.

A P3D hydraulic fracture propagation model should be run to determine what needs to be mixed and pumped into the well to achieve the optimum values of propped fracture length and fracture conductivity. The base data set should be used to make a base case run. Then, the engineer determines which variables are the most uncertain. Many times, the values of *in-situ* stress, modulus, permeability, fluid loss coefficient, for example, are not known with certainty and have to be estimated. The design engineer acknowledges these uncertainties and makes sensitivity runs with the P3D model to determine the effect of these uncertainties on the design process. As databases are developed, the number and magnitude of the uncertainties will diminish.

In effect, the design engineer should fracture treat the well many times on his or her computer screen. Making these sensitivity runs will (1) lead to a better design and (2) educate the design engineer on how certain variables affect the ultimate values of both the created and the propped fracture dimensions. Such designs will be comprehensive, will consider uncertainties, and will be developed using professional processes.

Fracturing Fluid Selection

A critical decision by the design engineer is the selection of the fracture fluid for the treatment. Economides *et al.* [24] developed a flow chart that can be used to select the category of fracture fluid on the basis of factors such as reservoir temperature, reservoir pressure, the expected value of fracture half-length, and a determination if the reservoir is water sensitive. Their fluid selection flow chart for a gas well is presented in Fig. 14.

Most productive coal seam reservoirs are less than 5000 ft deep. The permeability in highly cleated coal seams decreases with increasing depth and overburden stress. At depths greater than about 5000 ft, in most cases, the coal seam does not have enough permeability to be economically developed.

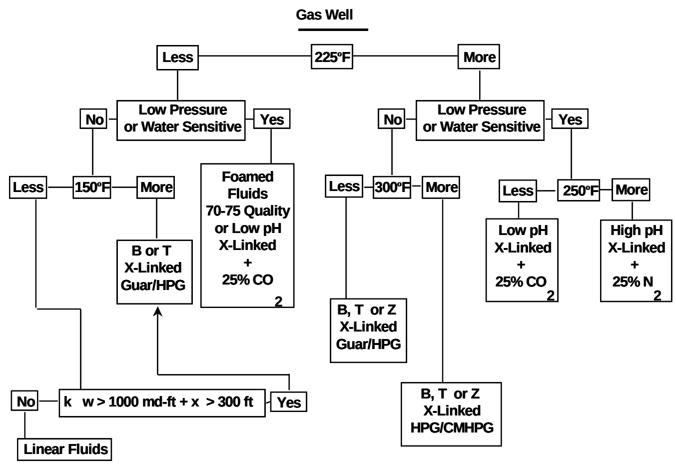


Fig. 14 – Selecting a fracture fluid.

Because most productive coal seams are shallow, low temperature reservoirs, then the choice of fracturing fluid (according to Fig. 14) will be (1) N_2 foam for low pressure reservoirs, (2) linear water based fluids if all you need is a short, low conductivity fracture, or (3) cross-linked gel if you need a wide or long fracture. Holditch *et al.*[14] discussed the criteria for selecting a fracturing fluid in the Gas Research Institute's Coal Seam Stimulation Manual.

For thick highly cleated coals, a crosslinked fluid should be used to create wide fractures and place as much proppant as possible in the fractures close to the wellbore. The purpose of the treatment is to link up the cleats to the wellbore using the hydraulic fracture and the proppant. The fluid should use the minimum amount of gel possible and breaker should be used to minimize damage to the fracture, and to assist in cleanup.

If the fracture is intended to connect up several thin coal seams that are vertically scattered up and down the wellbore, then coil tubing can be used to selectively stimulate each coal seam. Fig. 15 illustrates how coil tubing can be used to stimulated multiple intervals, one at a time.

- Single or multiple fracturing stimulation using coiled tubing as a conduit for both the isolation and the treatment.

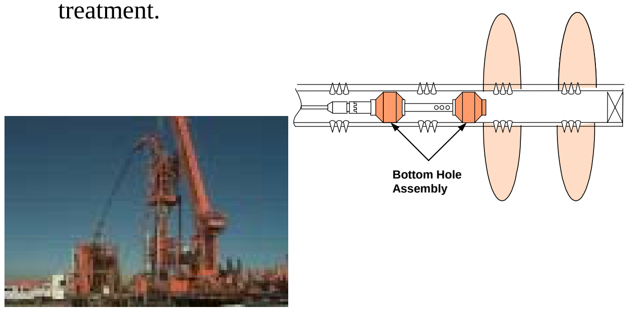


Fig. 15 – Fracturing using coil tubing.

In low-pressure coal seams, N_2 foam can be used as the fracture fluid. Foamed fracture fluids will create wide fractures, can transport the propping agent, and are easier to clean up than fluids that do not contain N_2.

Propping Agent Selection

Economides *et al.* [24] also produced a flow chart for selecting propping agents. Their chart is included as Fig. 16. Because most productive coal seams are shallow, sand is always used as the propping agent. In certain cases, where proppant flow back becomes a problem, then resin-coated sand is sometimes used. Special care must be used to design such treatments, because at low temperature, it may be difficult to get the resin to set and to create the consolidated sand pack needed to prevent proppant flow back.

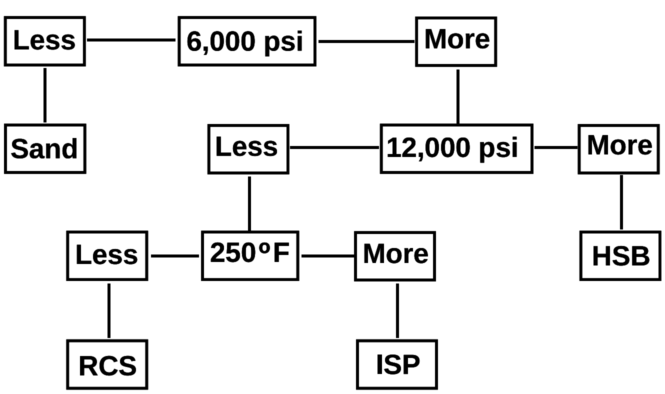


Fig. 16 - Proppant selection based on closure pressure.

To determine the optimum fracture conductivity, the design engineer should use the dimensionless conductivity (Cr) concept published by Cinco-Ley [25].

$$C_r \; \frac{P_i \; K \; L_f}{wk_f} \qquad \text{Eq. 2}$$

where w is the fracture width (ft), k_f is the proppant permeability (md), k is the formation permeability (md), and L_f is the fracture half-length. To minimize the pressure drop down the fracture, the value of Cr should be approximately equal to ten (10).

For example, in a coal seam, if the formation permeability is 25 md, and the optimum fracture half-length is 50 ft, then the optimum fracture conductivity would be 3,927 md-ft. The engineer needs to design the treatment to create a fracture wide enough, and pump proppants at concentrations high enough to achieve the high conductivity required to optimize the treatment.

Some engineers tend to compromise fracture length and conductivity in an often-unsuccessful attempt to prevent damage to the formation around the fracture. Holditch[26] showed that substantial damage to the formation around the fracture can be tolerated as long as the optimum fracture length and conductivity are achieved. Ideally, the design engineer can create the optimum fracture length and conductivity while minimizing damage to the formation. If the opposite occurs, that is, the formation is not damaged, but the fracture is not long enough or conductive enough, then the well performance will be disappointing.

The operator of the well should always evaluate the risks such as mechanical risks, product price risks and geologic risks. Uncertainties in the input data can be evaluated by making sensitivity runs using both the reservoir models and the fracture propagation models. One of the main risks in hydraulic fracturing is that the entire treatment will be pumped and/or paid for (i.e. the money is spent), but for whatever reason, the well does not produce at the desired flow rates nor recovers the expected cumulative recovery. Many times, mechanical problems with the well or the surface equipment cause the treatment to fail. Other times, the reservoir does not respond as expected.

To evaluate the risk of mechanical or reservoir problems, the design engineer can use 100% of the costs on only a fraction of the revenue in the economic analyses. For example, say one (1) in every five (5) fracture treatments in a certain formation is not successful. Then one can use 80% of the expected revenue and 100% of the expected costs to determine the optimum fracture length. An illustration of how such an analyses can alter the desired fracture length is presented in Fig. 17.

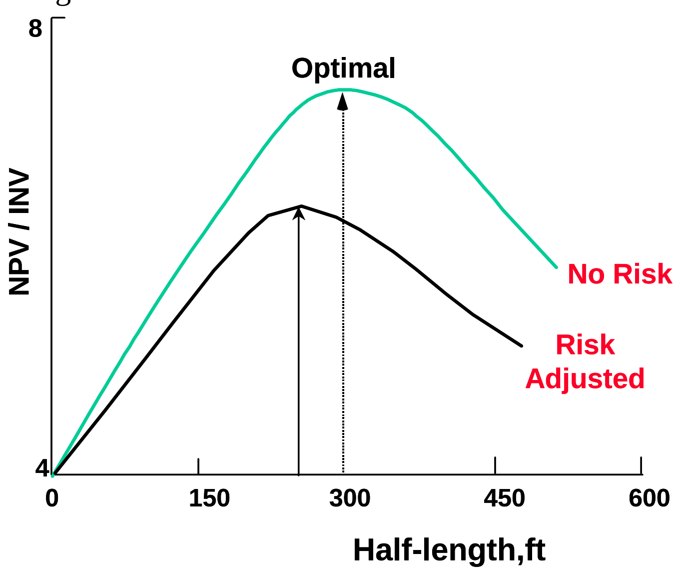


Fig. 17 – Economic analysis.

Finally, after the optimum, risk adjusted fracture treatment has been designed, it is extremely important to be certain the optimum design is pumped correctly into the well. For this to occur, the design engineer and the service company should work together to provide quality control before, during and after the treatment is pumped. The best engineers tend to spend sufficient time in the office to design the treatment correctly, then go to the field to help supervise the field operations (or provide on-site advice to the supervisor).

7. Post-Fracture Well Behavior

The original fracture treatments in the 1950's were designed to increase well productivity. These treatments were normally pumped to remove damage in moderate to high permeability wells. McGuire and Sikora[27] and Prats[28] published equations that were used for many years to design fracture treatments that resulted in desired folds of increase in the productivity index of a well. The productivity index of an oil well is

$$J = \frac{q_o}{(p_e - p_{wf})} \qquad \text{Eq. 3}$$

and for a gas well is

$$J = \frac{q_g \;\; \mu \, z}{(p_e^2 - p_{wf}^2)} \qquad \text{Eq. 4}$$

J is the productivity index in terms of barrels per psi per day or mcf per psi squared per day. The viscosity and compressibility are included in the equation for productivity index of a gas well, because they are pressure dependent.

Assuming J is the productivity index for a fractured well at steady state flow, and Jo is the productivity index of the same well under radial flow conditions, Prats[28] found that

$$\frac{J}{J_o} = \frac{\ln\left(\dfrac{r_e}{r_w}\right)}{\ln\left(\dfrac{r_e}{0.5\,L_f}\right)} \qquad \text{Eq. 5}$$

for a well containing an infinite conductivity fracture whose fracture half-length is L_f. Prats found that a well with a fracture half-length of 100 ft will produce as if the well had been drilled with a 100 ft diameter drill bit. In other words, the hydraulic fracture, if conductive enough, acts to extend the wellbore and stimulate flow rate from the well. If the dimensionless fracture conductivity, Cr (Eq. 2), is equal to 10 or greater, the hydraulic fracture will essentially act as if it is an infinately conductive fracture.

In coal seam reservoirs, the gas diffuses through the coal into the cleat system. If the cleat system is poorly developed and the permeability of the coal is low (<<1md), then the coal reservoir will probably not be economic to produce because it is almost impossible to create long, conductive fractures in thin coal seams. Thus, most commercial coal seam reservoirs are highly cleated, moderate permeability (5md<k<100md) reservoirs. As such, short, conductive fractures are required and large volumes of fluids are not needed to stimulate highly cleated coal seam reservoirs. The object of a hydraulic fracture in a highly cleated coal seam is to connect the cleat system with the well bore using the hydraulic fracture fluids and proppants.

8.0 Fracture Diagnostics

Fracture diagnostics involves analyzing the data before, during and after a hydraulic fracture treatment to determine the shape and dimensions of both the created and propped fracture. Fracture diagnostic techniques have been divided into several groups.[29]

Group 1 – Direct far field techniques

Direct far field methods are comprised of tiltmeter fracture mapping and microseismic fracture mapping techniques. These techniques require delicate instrumentation that has to be emplaced in boreholes surrounding and near the well to be fracture treated. When a hydraulic fracture is created, the expansion of the fracture will cause the earth around the fracture to deform. Tiltmeters can be used to measure the deformation and to compute the approximate direction and size of the created fracture. Surface tiltmeters are placed in shallow holes surrounding the well to be fracture treated and are best for determining fracture orientation and approximate size. Downhole tiltmeters are placed in vertical wells at depths near the location of the zone to be fracture treated. As with surface tiltmeters, downhole tiltmeter data can be analyzed to determine the orientation and dimensions of the created fracture, but are most useful for determining fracture height. Tiltmeters have been used on an experimental basis to map hydraulic fractures in coal seams.[11]

Microseismic fracture mapping relies on using a downhole receiver array of accelerometers or geophones to locate microseisms or micro-earthquakes that are triggered by shear slippage in natural fractures surrounding the hydraulic fracture. The principle of microseismic fracture mapping[29] is illustrated in Fig. 18. In essence, noise is created in a zone surrounding the hydraulic fracture. Using sensitive arrays of instruments, the noise can be monitored, recorded, analyzed and mapped.

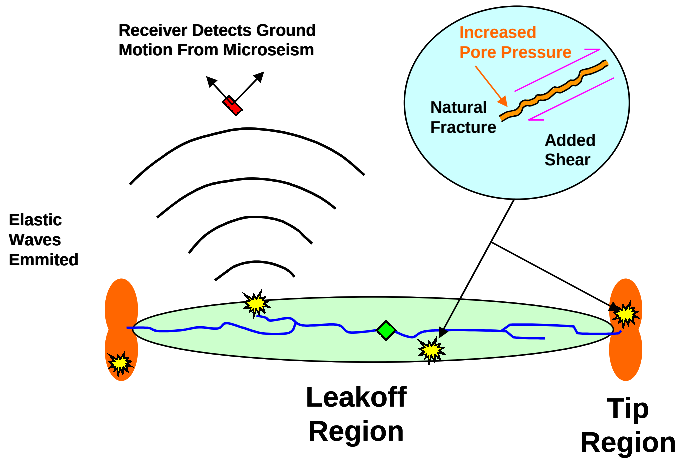


Fig. 18 – Principle of microseismic fracture mapping.

Tiltmeters have been used extensively in the oil and gas industry for more than 10 years, although it has only been recent that the technology has been available to look at fractures at depths greater than 4,000ft. Current surface tiltmeter technology can see below 10,000ft. Microseismic monitoring has traditionally been too expensive to be used on anything but research wells, but its cost has dropped dramatically in the past few years, so although still expensive (on the order of $50,000 to $100,000), it is being used more commonly throughout the industry. As with all monitoring and data collection techniques, however, the economics of marginal wells makes it difficult to justify any extra expense. If the technology is used at the beginning of the development of a field, however, the data and knowledge gained are often used on subsequent wells, effectively spreading out the costs.

<u>Group 2 – Direct near-wellbore techniques</u>

Direct near-wellbore techniques are run in the well that is being fracture treated to locate or image the portion of fracture that is very near (inches) the wellbore. Direct near-wellbore techniques consist of tracer logs, temperature logging, production logging, borehole image logging, downhole video logging, and caliper logging. If a hydraulic fracture intersects the wellbore, these direct near-wellbore techniques can be of some benefit in locating the hydraulic fracture.

However, these near-wellbore techniques are not unique and can not supply information on the size or shape of the fracture once the fracture is 2-3 wellbore diameters in distance from the wellbore. In coal seams, where multiple fractures are likely to exist, the reliability of these direct near-wellbore techniques are even more speculative. As such, very few of these direct near-wellbore techniques are used on a routine basis to look for a hydraulic fracture.

<u>Group 3 – Indirect fracture techniques</u>

The indirect fracture techniques consist of hydraulic fracture modeling of net pressures, pressure transient test analyses, and production data analyses. Because the fracture treatment data and the post-fracture production data are normally available on every well, the indirect fracture diagnostic techniques are the most widely used methods to determine the shape and dimensions of both the created and the propped hydraulic fracture.

The fracture treatment data can be analyzed with a P3D fracture propagation model to determine the shape and dimensions of the created fracture. The P3D model is used to history match the fracturing data, such as injection rates and injection pressures. Input data, such as the *in-situ* stress and permeability in key layers of rock can be varied (within reason) to achieve a history match of the field data.

Post-fracture production and pressure data can be analyzed using a 3D reservoir simulator to estimate the shape and dimensions of the propped fracture. Values of formation permeability, fracture length and fracture conductivity can be varied in the reservoir model to achieve a history match of the field data.

The main limitation of these indirect techniques is that the solutions are not very unique and require as much fixed data as possible. For example, if the engineer has determined the formation permeability from a well test or production test prior to the fracture treatment, so that the value of formation permeability is known and can be fixed in the models, the solution concerning values of fracture length become more unique. Most of the information in the literature concerning post-fracture analyses of hydraulic fractures has been derived from these indirect fracture diagnostic techniques.

Limitations of fracture diagnostic techniques

Warpinski discussed many of these same fracture diagnostic techniques.[30] Table 6, from Warpinski's paper, lists certain diagnostic techniques and their limitations. In general, fracture diagnostics is expensive and only used in research wells. Fracture diagnostic techniques do work and can provide important data when entering a new area or a new formation. However, in coal seam wells, where costs must be minimized to maintain profitability, fracture diagnostic techniques are rarely used and are generally cost prohibitive.

Table 6 – Limitations of Fracture Diagnostic Techniques

Parameter	Technique	Limitation
Fracture Height	Tracer logs	Shallow depth of investigation; shows height only near the wellbore
Fracture Height	Temperature logs	Difficult to interpret; shallow depth of investigation; shows height only near wellbore
Fracture Height	Stress profiling	Does not measure fracture directly; must be calibrated with *in-situ* stress tests
Fracture Height	P3D models	Does not measure fracture directly; estimates vary depending on which model is used
Fracture Height	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Height	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Length	P3D models	Length inferred, not measured; estimates vary greatly depending on which model is used
Fracture Length	Well testing	Large uncertainties depending upon assumptions and lack of prefracture welltest data
Fracture Length	Microseismic	Optimally requires nearby offset well; difficult to interpret; expensive
Fracture Length	Tiltmeters	Difficult to interpret; expensive and difficult to conduct in the field
Fracture Azimuth	Core techniques	Expensive to cut core and run tests; multiple tests must be run to assure accuracy
Fracture Azimuth	Log techniques	Requires open hole logs to be run; does not work if natural fractures are not present
Fracture Azimuth	Microseismic	Analysis intensive; expensive for determination of azimuth
Fracture Azimuth	Tiltmeters	Useful only to a depth of 5000 ft; requires access to large area; expensive

9.0 Nomenclature

CMHPG	=	Carboxymethylhydroxypropyl-guar
HEC	=	Hydroxyelthycellulose
HPG	=	Hydroxypropylguar
ISIP	=	Instantaneous shut-in pressure
ISP	=	Intermediate strength proppant
k	=	Formation permeability, md
KCL	=	Potassium chloride
KGD	=	Kristonovich, Geertsma, Daneshy
L_f	=	Fracture half-length, ft
LWP	=	Light weight proppant
MEOH	=	Methanol
MRO	=	Memory readout gauge
NH_4CL	=	Ammonium chloride
PKN	=	Perkins, Kern, Nordgren
RSC	=	Resin coated sand
SRO	=	Surface Readout gauge
wk_f	=	Fracture conductivity, md-ft
α	=	Biot's constant
ν	=	Poissons' ratio
σ_{ext}	=	Tectonic stress
σ_{min}	=	Minimum horizontal stress (*in-situ* stress)
σ_{ob}	=	Overburden stress
σ_p	=	Reservoir fluid pressure or pore pressure
σ_1	=	Vertical (overburden) stress
σ_2	=	Minimum horizontal stress
σ_3	=	Maximum horizontal stress

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Appendix B

Quality Assurance Plan: Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs

The U.S. Environmental Protection Agency (EPA), bases environmental protection efforts on the best available scientific information and sound science. The credibility of the resulting policy decision depends, to a large extent, on the strength of the scientific evidence on which it is based. Sound science can be described as organized investigations and observations conducted by qualified personnel using documented methods and leading to verifiable results and conclusions (SETAC, 1999).

This Quality Assurance Plan for data collection and evaluation describes the procedures the Agency used for a systematic and well-documented, graded approach to realizing the goal for the "Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs." The goal of Phase I of EPA's hydraulic fracturing study was to assess the potential for contamination of USDWs due to the injection of hydraulic fracturing fluids into CBM wells and to determine based on these findings, whether further study is warranted. This Quality Assurance Plan (developed following the guidelines of EPA publication 240/B-01/003) guides the production of a set of data and scientific findings that are sound, with conclusions supported by the data.

1.0 Project Management

This section of the Quality Assurance Plan addresses the basic area of project management, including the project history and objectives, and roles and responsibilities of the participants.

1.1 Project and Task Organization

Overall project management was provided by the EPA's Office of Water, Groundwater and Drinking Water (OGWDW), Groundwater Protection Division. Data was gathered by an EPA OGWDW contractor.

The contractor compiled the gathered data into a draft summary report, reviewed the draft report, and submitted the draft report to EPA and other federal agencies for review. After the contractor addressed comments from EPA and other federal agencies, EPA submitted the draft report to a Peer Review Panel for their comments (see Table B-1 for a list of the members of the Peer Review Panel). Following receipt of comments from the Peer Review Panel, EPA and its contractors responded to those comments. The availability of the report for stakeholder review and comment was announced in the *Federal Register* on August 28, 2002.

Table B-1: Peer Review Panel

Name	Affiliation	Education	Experience
Morris Bell	Engineer, Colorado Oil and Conservation Commission	Engineering Degree, University of Oklahoma	Closely involved with coalbed methane development in the San Juan and Raton Basins. Has investigated water well complaints and directed projects to test water wells. Worked for Amoco as a production engineer, drilling and completing tight gas wells. Also worked as a consultant, specializing in the completion and evaluation of coalbed methane wells.
Peter E. Clark	Associate Professor, Dept. of Chemical Engineering and Material Science, University of Alabama	Ph.D., University of Oklahoma State University	Specializes in complex fluid flows and hydraulic fracturing. Has taught several courses in the Chemical Engineering, Mineral Engineering, Engineering Mechanics, and Civil Engineering Departments. These courses included fluid mechanics, petroleum rock and fluids, well completion, drilling, and natural gas engineering.
David Hill	Manager, Engineering Resources, Gas Technology Institute (GTI)	MBA, Northwestern University; BS, Marietta College, Petroleum Engineering	Expertise includes unconventional reservoirs (e.g., coalbed methane, gas shales, tight sands); hydraulic fracturing; and reservoir evaluation in technical, managerial, and marketing aspects of technology development, deployment, and commercialization. Has authored and co-authored over 40 articles about oil- and gas-related research and development, and field-based operations.

Table B-1: Peer Review Panel

Name	Affiliation	Education	Experience
Buddy McDaniel	Technical Advisor for Production Enhancement Technology, Halliburton	B.S., Chemical Engineering, University of Oklahoma	Specializes in applications for highly deviated and horizontal wellbores and understanding of reservoir response to fracturing applications. Conducted research related to laboratory measurement of fracture conductivity of proppants under simulated reservoir conditions. Was actively involved in design and application of hydraulic fracturing treatments in soft chalks, deviated and horizontal wellbores, gas storage wells, geothermal wells, and conventional hydrocarbon reservoirs.
Jon Olson	Asst. Professor, Dept. of Petroleum and Geosystems Engineering, University of Texas at Austin	Ph.D., Stanford University, Applied Earth Sciences	Worked in the areas of fracture mechanics and coal geology and has published several papers on these subjects. Was employed by Mobil Exploration for several years as research engineer in the areas of rock mechanics, structural geology, and well performance.
Ian Palmer	Senior Petroleum Engineer, BP Amoco	Ph.D., University of Adelaide in Australia	Has worked extensively in coalbed methane extraction, including fracture design and prediction, rock mechanisms of coal, and openhole cavity completions. Also developed hydraulic fracturing models.
Norm Warpinski	Distinguished Member of Technical Staff, Sandia Laboratories	Ph.D., University of Illinois, Mechanical Engineering	Authority on hydraulic fracturing, geomechanics, poroelasticity, in situ stresses, and production mechanisms. Has expertise ranging from theoretical modeling and laboratory testing to field and in situ mineback experiments. Serves as project manager and lead scientist for a program to develop hydraulic fracture diagnostic technology for use in industry fracturing applications. Has published extensively on subject of hydraulic fracturing.

1.2 Problem Definition and Background

Hydraulic fracturing is a half century-old technology used in oil and natural gas production. The hydraulic fracturing process uses very high hydraulic pressures to initiate a fracture. A hydraulically induced fracture acts as a conduit in the rock or coal formation that allows the oil or coalbed methane to travel more freely from the rock pores (where the oil or methane is trapped) to the production well that can bring it to the surface.

After a well is drilled into a reservoir rock that contains oil, natural gas, and water, every effort is made to maximize the production of oil and gas. One way to improve or maximize the flow of fluids to the well is to connect many pre-existing fractures and flow pathways in the reservoir rock with a larger fracture. This larger, man-made fracture starts at the well and extends out into the reservoir rock for as much as several hundred feet. To create or enlarge fractures, a thick fluid, typically water-based, is pumped into the coal seam at a gradually increasing rate and pressure. Eventually the coal seam is unable to accommodate the fracturing fluid as quickly as it is injected. When this occurs, the pressure is high enough that the coal fractures along existing weaknesses within the coal. Along with the fracturing fluids, sand (or some other propping agent or “proppant”) is pumped into the fracture so that the fracture remains “propped” open even after the high fracturing pressures have been released. The resulting proppant-containing fracture serves as a conduit through which fracturing fluids and groundwater can more easily be pumped from the coal seam.

To initiate coalbed methane production, groundwater and some of the injected fracturing fluids are pumped out (or “produced” in the industry terminology) from the fracture system in the coal seam. As pumping continues, the pressure eventually decreases enough so that methane desorbs from the coal, flows toward, and is extracted through the production well.

EPA is conducting a study to assess the potential for contamination of underground sources of drinking water (USDWs) due hydraulic fracturing fluid injection into coalbed methane wells. The study focuses on hydraulic fracturing used specifically for enhancing coalbed methane production. EPA, through its contractors and subcontractors, gathered information on the hydraulic fracturing process and requested comment from the public on contamination allegedly due to hydraulic fracturing practices. In this Phase I effort, EPA did not incorporate new, scientific fact finding, but used existing sources of information, and consolidated pertinent data in a summary report to serve as the basis for the study. EPA decided if additional research was required based on the findings from this effort.

1.3 Project and Task Description

The purpose of this project is to assist EPA in assessing the potential for contamination of USDWs from the injection of hydraulic fracturing fluids into coalbed methane wells, and to determine based on these findings if further study is warranted. EPA will use the information from this study in any regulatory or policy decisions regarding hydraulic fracturing. The first step in investigating the potential for hydraulic fracturing to affect the quality of USDWs was to define mechanisms by which contamination could occur.

EPA defined two hypothetical mechanisms by which hydraulic fracturing of coalbed methane wells could potentially impact USDWs:

1. Direct injection of fracturing fluids into a USDW in which the coal is located, or injection of fracturing fluids into a coal seam that is already in hydraulic communication with a USDW (e.g., through a natural fracture system).

2. Creation of a hydraulic connection between the coalbed formation and an adjacent USDW.

The objective of the project is to consider these two mechanisms, based on existing literature and data, when evaluating whether hydraulic fracturing fluid injection into coalbed methane wells could contaminate USDWs.

Information was collected regarding the geology and hydrogeology of the coalbed methane production regions, the processes used to hydraulically fracture coalbed methane production wells, and the fluids used in the fracturing process. EPA also evaluated water supply incidents possibly related to hydraulic fracturing of coalbed methane production wells. EPA relied on currently available literature and data as the primary source of information for project efforts.

1.4 Quality Objectives and Criteria

To ensure that findings are valid, the following quality assurance questions will be addressed for all sources of data:

- What was the purpose of the study?
- Whose data are they?
- What is their source?
- Are the data reliable?
- Is the interpretation biased?

This Quality Assurance Plan establishes a set of guidelines and general approaches to assess available data and information in a clear, consistent, and explicit manner. Data collection and review according to this process will make conclusions more transparent, and thus more readily understood and communicable to stakeholders.

The objectives of the systematic expert review of data and information are transparency, avoidance of bias, validity, replicability, and comprehensiveness. Following a data and information review protocol can ensure a common understanding of the task and adherence to a systematic approach. The components of this Quality Assurance Plan are as follows:

- Specification of the hypotheses to be addressed;
- Justification of the expertise represented in the expert investigators team;
- Specification of the methods to be used for identification of relevant studies, assessment of evidence of the individual studies, and interpretation of the entire body of available evidence (WHO, 2000);
- Review process; and
- Communication of findings.

Revisions to the Quality Assurance Plan may be necessary as new aspects of the task emerge during the study development process.

1.5 Special Training and Certification

To provide authoritative assessments of data and information, it is important to rely on expert investigators to evaluate the evidence, draw conclusions on the existence of actual and/or potential hazard, and estimate the magnitude of the associated risk. The team of expert investigators, that evaluated the evidence associated with this study, possesses the following qualifications:

- Formal training in basic scientific principles applicable to the project;
- Basic knowledge of the subject or the body of technical information pertaining to it;
- Experience in scientific review of technical data and information;
- Ability to use descriptive and analytical tools appropriately;
- Ability to design studies to test hypotheses;
- Ability to communicate results accurately to decision-makers and stakeholders; and
- Experience coordinating multiple tasks and disciplines to ensure timely and accurate delivery of study components.

The above-listed qualifications ensure that the project team was able to fulfill the objectives of this project.

1.6 Documents and Records

Documents produced for the project and submitted to EPA included the draft and final summary reports (hard copy and digital format). Information and records included in the data report package following completion of the project included:

- Maps (hard copies);
- Scientific literature (hard copies);
- Books (hard copies);
- Database search results (hard copies);
- Logbooks (hard copies); and
- Site visit notes and photographs (hard copies).

All the above-listed materials are maintained by the EPA OGWDW.

2.0 Data Generation and Acquisition

Processes and methods used to collect the data and information must be clear, explicit, and based on valid practice. It is important to adhere to a rigorous and thorough approach to the processes of data collection and data logging.

In Phase I, EPA did not incorporate new, scientific fact finding, but instead used existing sources of information, and consolidated pertinent data in a summary report to serve as the basis for the study. EPA decided if additional research is required based on the findings from this effort. As such, this Quality Assurance Plan does not cover areas of sampling process design, sampling methods, sample handling and custody, analytical methods, quality control, instrument/equipment testing, inspection, and maintenance, instrument/equipment calibration and frequency, and inspection/acceptance of supplies and consumables.

2.1 Non-Direct Measurements

All information summaries and conclusions developed during the course of this project were based on non-direct measurements. Available literature and data were used as the primary source of information for the summary report. An extensive literature search was conducted using the Engineering Index and GeoRef on-line reference databases. Searches will be guided by subject topics and key words within the following areas:

- Hydrogeology of the coalbed methane basins;
- Hydraulic fracturing practices;
- Fracture behavior;
- Hydraulic fracturing fluids and additives; and
- Information regarding water quality incidents.

All search results were printed, catalogued, and surveyed for pertinent journal articles, books and conference proceedings that may contain information meeting the specific data needs of the summary report. Most pertinent articles were acquired from the University of Texas Library in Austin, Texas, as this library's holdings include an extensive collection of oil and gas-related publications. References from the articles were researched and documents relevant to the study were acquired. All papers collected for the study were archived by topic for future reference.

To verify facts extracted from the literature, state regulatory agencies, geological surveys, gas companies, service companies and other relevant organizations were contacted by telephone. Dated telephone logs were used to document all communications. Personal conversations with the employees of the various organizations yielded additional information in the form of literature, figures and maps. These were collected and referenced in conjunction with literature identified in the literature searches.

Internet-based searches were used to locate additional information. Relevant web sites were located using various search engines such as Google™, Yahoo®, and Alta Vista®. More specialized search engines, such as those provided on state geological survey web sites, also were searched. All relevant web sites were logged and referenced appropriately. Efforts were made to acquire the most recent literature. EPA offered state drinking water agencies and the public an opportunity to provide information to EPA on any impacts to groundwater believed to be associated with hydraulic fracturing by a request for public comment. Submissions were reviewed by EPA staff for information pertinent to this report. In addition, a request to provide information and comments regarding incidents of public and private well impacts that could potentially be associated with hydraulic fracturing was published in the July 30, 2001 *Federal Register* (*Federal Register*: July 30, 2001; Volume 66; Number 146; Page 39395-39397).

Details on specific methods used to collect information for each of the major report chapters is included in Chapter 2 of this report.

2.2 Data Management

Gathered information and data was managed to facilitate finding any one piece of gathered data. To achieve this goal, the following data management procedures were used:

- All telephone interviews were recorded in labeled log books;
- All scientific literature, published maps, existing water quality data, conference proceedings, and trade journal articles were filed by coal basin;
- Material safety data sheets and product literature were filed separately;
- Trip folders (to contain notes and photographs) were generated for each site visit;
- Computer database searches were filed separately; and
- Internet websites were referenced in the summary report.

Most data was stored in hard copy format. Wherever possible, data was stored digitally on compact disc.

3.0 Assessment and Oversight

The quality assurance review process provides a means to examine if the results and conclusions are verifiable. The review process results in a determination of whether the conclusions are directly supported by the data or evidence gathered and can be independently validated by others. This quality assurance review process is hierarchical and includes four review levels:

- Weighted emphasis on data based on source;
- Cross referencing of data sources when possible;
- EPA and other federal agencies review; and
- Review by a Peer Review Panel.

EPA's review was accomplished by the Work Assignment Manager in conjunction with other EPA headquarter offices and with other EPA Underground Injection Control regional offices involved with coalbed methane or hydraulic fracturing. Other federal agencies asked to review work products produced by this project, included the United States Geological Survey and the Department of Energy.

EPA assembled a peer review panel consisting of experts in hydraulic fracturing or associated subjects. The panelists provided comments to EPA regarding the sources of data used in the study, the data themselves, and the conclusions drawn from those data.

Comments were requested to assist the investigators in making the study as sound as possible and to ensure that the study met EPA standards for objectivity, evidence, and responsiveness to the study charge. Reviewer comments and objections were preserved and made a part of the record for the study. Issue papers were written containing detailed explanations of responses to comments and objections. Reasons for proceeding or not proceeding with the study were clearly explained.

4.0 Data Validation and Usability

This section describes activities that occurred after the initial collection of data. These activities determined whether or not the gathered data were useful and helpful to the project.

4.1 Data Review, Verification, and Validation

Subsequent to the data logging process, those reports potentially providing useful information underwent a selection process to evaluate quality of the information and usefulness to the study. Systematic evaluation of the validity of individual studies, data, and information included assessment of the following:

- Source of the data and information;
- Qualitative review of the literature;
- Qualitative review of data and information collected;
- Scientific strength of the data and information;
- Geographical, geological, geochemical, spatial, and temporal relevance;
- Relevance to determining baseline conditions;
- Validity of extrapolation to the scope of the study;
- Characteristics of associations, plausibility, alternative explanations;
- Consistency and specificity of the results;
- Scientific uncertainties, limitations, and confounding variables; and

- Other evaluation parameters, as appropriate.

A scale or rating of the data and information with respect to a level of proof required to support conclusions is specifically not proposed as part of this quality assurance process. Establishing a specific level of scientific evidence required to justify a subsequent conclusion would generate significant controversy. Instead, expert judgment was used to evaluate and weigh available data and information.

A variety of technical methods and tools were utilized to sort through the pertinent information and decipher the meaning of the data. These data analysis methods may include:

- Quantitative review of selected data and information collected;
- Tabulating valid data and information;
- Constructing geologic cross sections;
- Evaluating current and historical site operations;
- Review of consistencies between studies;
- Review of sources of discrepancies between studies and information; and
- Other methods/tools as appropriate.

All assumptions were explicitly documented, the basis for the use of any models explained, lack of evidence noted, and scientific uncertainties described as precisely as possible.

4.2 Reconciliation with User Requirements

This sub-section describes how the gathered and validated data and information were used to meet the requirements of this project and EPA.

4.2.1 Drawing Conclusions

Drawing conclusions from evaluated, analyzed, and summarized data and information involve judgment as to whether observations are consistent with the study hypotheses/objectives, or, whether some alternative is suggested. The expert investigators drew upon all evaluated and appropriately summarized data and information; however, no checklist or formula was applied to arrive at conclusions. Instead, critical scientific reasoning and judgment was used to draw conclusions. The process of scientific reasoning and judgment was made explicit by describing and documenting how investigators:

- Assessed completeness of data and information;
- Accounted for lack of evidence and limitations, and impacts on the conclusions;
- Assessed and accounted for bias in original data and/or information;
- Used applicable guidelines and rationales;
- Used any ranges of estimates to arrive at conclusions, where appropriate and;
- Incorporated assumptions into assessments and accounted for the implications of those assumptions in their conclusions.

Conclusions were drawn within the boundaries of the data and the scope of the study. Lack or absence of evidence was addressed. The relative strength or weakness of available information to support conclusions, limitations on where a conclusion may apply, and alternative interpretations of data, was recognized. Any qualification on the use of the data and factors that contribute to uncertainty was conveyed.

Much of the information obtained from public response to the *Federal Register* Notice or from other sources cannot be confirmed through review of peer-reviewed publications or other data sources. However, the information was reviewed and contrasted to evaluate the extent of complaints received and any trends in the complaints within and between individual coalbed methane production basins.

4.2.2 Communication of Findings

This Quality Assurance Plan is reflected in the communication of scientific findings in a clear, accurate, and complete manner to interested parties. Investigators communicated:

- The body of technical information that was considered;

- The manner for evaluating, and drawing conclusions from, collected data and information; and

- Conclusions that address the hypotheses/objectives, supported by the results of data evaluation and analysis.

The use of presentation tools such as charts, diagrams, and computer-generated displays was based on sufficient, valid, and defensible data.

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Attachment 1
The San Juan Basin

The San Juan Basin covers an area of about 7,500 square miles across the Colorado/New Mexico line in the Four Corners region (Figure A1-1). It measures roughly 100 miles long in the north-south direction and 90 miles wide. The Continental Divide trends north-south along the east side of the basin, and land surface elevations within the basin range from 5,100 feet on the western side to over 8,000 feet in the northern part.

The San Juan Basin is the most productive coalbed methane basin in North America. Coalbed methane production in the San Juan Basin totaled over 800 billion cubic feet (Bcf) in 1996 (Stevens et al., 1996). This number rose to 925 Bcf in 2000 (GTI, 2002). The coals of the Upper Cretaceous Fruitland Formation range from 20 to over 40 feet thick. Total net thickness of all coalbeds ranges from 20 to over 80 feet throughout the San Juan Basin. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped within the underlying and adjacent Pictured Cliffs Sandstone, and many wells are completed in both zones. Coalbed methane wells in the San Juan Basin range from 550 to 4,000 feet in depth, and about 2,550 wells were operating in 2001 (CO Oil and Gas Conservation Commission and NM Oil Conservation Division, 2001).

1.1 Basin Geology

The San Juan Basin is a typical asymmetrical, Rocky Mountain basin, with a gently dipping southern flank and a steeply dipping northern flank (Figure A1-2) (Stone et al., 1983). The Fruitland Formation is the primary coal-bearing unit of the San Juan Basin and the target of most coalbed methane production. Geologic cross sections showing generalized relationships between the Fruitland Formation and adjacent are shown in A1-4 through A1-6. The Fruitland coals are thick, with individual beds up to 80 feet thick. The Fruitland Formation is composed of interbedded sandstone, siltstone, shale, and coal. The stratigraphy of the Fruitland Formation is predictable throughout the basin, as follows:

- The thickest coalbeds are always found in the lower third of the formation;
- Pictured Cliffs Sandstone occurs immediately below the formation;
- Sandstone content is greater in the lower half; and
- Siltstone and shale predominate in the upper half (Choate et al., 1993).

The San Juan Basin may be subdivided into three unique regions, based on similar geologic, hydrologic, and production characteristics (Figure A1-7). These regions are denoted as Area 1, Area 2, and Area 3, and are described in more detail below (Kaiser and Ayers, 1994).

Area 1 consists of the northwestern quarter of the basin. Area 1 is characterized by the thickest (>20 feet) and highest-rank coal deposits in the San Juan Basin (Ayers et al., 1994). Most wells produce more than 1,000 cubic feet per day and several wells produce more than 15,000 cubic feet per day. Almost 90 percent of total methane production from the Fruitland Formation comes from three fields in a region of Area 1 known as the "Fairway" (Young et al., 1991; Ayers et al., 1994). Area 1 is an area of active recharge and in most places is hydrostatically over-pressured (greater than 0.50 pounds per square inch per foot). Wells in Area 1 usually produce moderate to large volumes of water, some of which meet the quality criteria of less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) for an underground source of drinking water (USDW) (Kaiser et al., 1994).

Area 2 (the west-central region of the San Juan Basin) is hydrostatically under-pressured (0.30 to 0.50 pounds per square inch per foot) and is an area of regional groundwater discharge. Coalbeds are usually 7 to 15 feet thick, and occur primarily in northwest-trending belts that extend to the southwestern margin of the basin. Methane production from wells can be more than 100 thousand cubic feet per day, and a few wells produce 200 to 500 thousand cubic feet per day. Methane gas is produced water-free in this area as a consequence of the hydrostratigraphy and trapping mechanisms (Kaiser and Ayers, 1994). Additionally, Kaiser and Ayers (1994) suggest that water may be less mobile in the hydrophilic and low permeability coals. The Fruitland Formation in this area where it is under-pressured generally shows the presence of saline-type waters (Kaiser et al., 1994) that most likely have TDS concentrations greater than 10,000 mg/L, which does not meet the criteria for a USDW.

Area 3, the eastern region of the San Juan Basin, is hydrostatically under-pressured, and features low permeability and low hydraulic gradient, which suggests slow water movement within most of the aquifer. Only a few coalbed gas wells are located in this part of the basin, and they produce up to 8,000 cubic feet of methane per day, with little or no water content (Kaiser and Ayers, 1994). Produced waters from the Fruitland Formation in most of Area 3 have a high-salinity, resembling seawater (Kaiser and Ayers, 1994) in which TDS are too high to meet the water quality criteria of a USDW. However, along the southern margin of Area 3, TDS concentrations are less than 10,000 mg/L (Kaiser et al., 1994).

1.2 Basin Hydrology and USDW Identification

Tertiary sandstones and Quaternary alluvial deposits are present at the surface over much of the basin interior. These serve as the primary drinking water aquifers in the basin (Figure A1-2), and produced 55 million gallons per day in 1985 (Wilson, 1986). Cretaceous sandstones are an important source of water on the basin's periphery (Choate et al., 1993). The Paleocene Ojo Alamo Sandstone yields as much as 30 gallons per minute of potable water (Hale et al., 1965) and is mentioned as one of the primary drinking water aquifers of the region (Brown and Stone, 1979). Cleats and larger fractures in the Fruitland coals and the presence of interbedded permeable sandstones make the Fruitland Formation an aquifer and source of drinking water along the northern margin of the basin where TDS in the groundwater are less than 10,000. In most of Area 1, both the Fruitland Formation and the underlying upper Pictured Cliffs Sandstone act as a single hydrologic unit (Kaiser et al., 1994). The Fruitland and upper Pictured Cliffs Sandstone aquifer is underlain and confined by the low-permeability main Pictured Cliffs Formation and is overlain and partly confined by the Kirtland shale, which is up to 1,000 feet thick in the central basin. Overlying the Kirtland Formation is the Ojo Alamo Sandstone, (Figures A1-4, A1-5 and A1-6) which has been suggested as a possible source of groundwater for the municipality of Bloomfield (Stone et al., 1983). At Bloomfield, the coal and gas bearing Fruitland is separated from the Ojo Alamo aquifer by the Kirtland shale.

In the northern part of the basin, the Fruitland Formation and the underlying upper Pictured Cliffs Sandstone can be considered a single hydrogeologic unit on a regional scale because they exhibit the same hydraulic head and water quality characteristics and are the source of both the water and gas in the Pictured Cliffs sand tongues (Ayers and Zellers, 1994; Ayers et al., 1994). At the local scale, however, the two formations appear to exhibit poor hydraulic continuity, as evidenced by areas of over-pressuring (greater than 0.5 pounds per square inch per foot), abrupt changes in potentiometric surface (Figure A1-8), and upward flow (Kaiser et al., 1994). Discrete flow within individual units here is likely due to pinch out of thick, laterally extensive coal seams and truncation and offset of the beds by faults.

In general, groundwater is recharged along the Fruitland outcrops at the elevated, west, northern, and northwestern margins of the basin, and lateral flow converges primarily from the northeast and southeast toward upward discharge to the San Juan River valley (Kaiser et al., 1994). In the north, the Fruitland and upper Pictured Cliffs Sandstone aquifer system is confined by the overlying Kirtland shale, but it is poorly confined by the Kirtland in the central and southern portions of the basin. Water from the Fruitland discharges in the western part of the basin and migrates upward across the Kirtland shale into the Animas and San Juan Rivers (Stone et al., 1983). Generalized groundwater movement in the Fruitland system is shown in cross-section and plan view in Figures A1-9 and A1-10 (Kaiser and Swartz, 1988). The results of groundwater flow modeling for the entire basin (Kaiser et al., 1994) are shown in Figure A1-11.

In most of Area 1, the Fruitland system produces water containing less than 10,000 mg/L TDS, the water quality criteria for a USDW. Groundwater is usually freshest at the outcrop in recharge areas. The water dissolves salts and mixes with formation water as it flows, and the groundwater becomes increasingly saline as distance from the recharge source increases. The presence of low-salinity water at given locations in the San Juan Basin usually marks close proximity to the recharge source or the most permeable flow paths and implies a dynamic, active aquifer system (Kaiser et al., 1994). Figure A1-12 shows the chloride concentration of groundwater in the Fruitland Formation, and indicates that water nearest the northern recharge areas has a low dissolved solids and chloride content. Kaiser et al. (1994) reported that wells in the northern part of Area 1 produced water containing from 180 to 3,015 mg/L TDS. This was found to be the case over large portions of Area 1, especially within freshwater plumes resulting from areas of high permeability or fracture trends (Kaiser and Swartz, 1990; Oldaker, 1991).

Kaiser et al. (1994) conducted a water-quality sampling program in the San Juan Basin. Analyses taken from Fruitland coal wells in Area 1 show that the majority of wells (16 of 27 wells) produce water containing less than 10,000 mg/L TDS, (Figures A1-13a and A1-13b), although some nearby wells thought to be in less permeable zones produce water with higher TDS concentrations up to 23,000 mg/L (Kaiser et al., 1994). The boundary between waters with more and less than 10,000 TDS has not been published. Another group of wells throughout the same area was also sampled, but these wells were completed (constructed) in the adjacent and underlying Pictured Cliffs Sandstone bodies, which are in hydrologic communication with the Fruitland system (Kaiser et al., 1994).

Although from the above information it would seem that the Fruitland would be classified a USDW, the following additional information about disposal of brackish water produced along with the methane would seem to indicate that most of the water in the Fruitland would not meet the TDS criteria for USDW. Coalbed methane wells in the San Juan Basin produced from 0 to over 10,500 gallons of water per day, which contain from less than 300 mg/L TDS to over 25,000 mg/L (Kaiser et al., 1994; Kaiser and Ayers, 1994). Brackish water of various TDS concentrations and brine are produced in the over-pressured Area 1 of the basin while virtually no water is produced from coalbed methane wells in Areas 2 and 3 of the basin. Cox (1993) reported "Water disposal in the San Juan basin is a significant, long-term issue." In 1992, coalbed methane wells produced over 5 million gallons of water per day, and production was expected to increase to over 7.5 million gallons per day by 1995 (Cox, 1993). Produced water is disposed of by means of evaporation ponds, or, more commonly, by Class II injection into deeper zones such as the Entrada and Bluff sandstones, Morrison Formation, and Mesa Verde sandstone (Kaiser and Ayers, 1994). The authors estimated that injection wells cost up to $2 million each and Cox (1993) reported that 51 of them had been constructed in the basin by 1993.

Area 2 is primarily an area of groundwater discharge. The Fruitland coals and Pictured Cliffs Sandstone in Area 2 are in hydraulic communication and behave as a single aquifer. The aquifer is under-pressured (less than 0.50 pounds per square inch per foot), transmits groundwater from the northeast and southeast, and eventually discharges to the

Animas and San Juan rivers. The TDS of most samples from Area 2 ranges from 10,000 to 16,000 mg/L (Kaiser et al., 1994).

The Fruitland system in most of Area 3 contains slow-moving water with salinity approximately equal to that of seawater, greater than 25,000 mg/L TDS, (Kaiser and Ayers, 1994). In Area 3, the Fruitland and Pictured Cliffs are separate, confined aquifers. In the southeastern one-third of Area 3, the Kirtland shale is absent because of Tertiary-age erosion, and the Fruitland and Ojo Alamo Sandstone could be in hydraulic communication with one another (Figure A1-6). In this area Tertiary rocks, including the Ojo Alamo, are mapped by the United States Geological Survey (Figure A1-14) as an aquifer having water with TDSs ranging from 500 to 1,000 mg/L (Lyford, 1979).

At the basin's southern margin in Area 3, downward flow occurs from the Ojo Alamo through the Kirtland shale to the poorly confined Fruitland aquifer through which it then moves southward to outcrops at a lower elevation and northward to the San Juan River Valley (Kaiser et al., 1994) (Figure A1-11). Twenty-four of 26 water samples from the Fruitland/Pictured Cliffs aquifer system in the south margin of the basin reported by Kaiser and Swartz (1994) had less than 9,000 mg/L TDS (Figure A1-13e & A1-13f). Groundwater in the Fruitland Formation at the southern margin of the basin has less than 10,000 mg/L TDS because most recharge there comes from above the Kirtland formation, rather than from southward throughput from the Fruitland Formation.

1.3 Coalbed Methane Production Activity

Coalbed methane production occurs primarily in coals of the Fruitland Formation. However, some methane is absorbed in the underlying and adjacent Pictured Cliffs Sandstone, therefore many wells are completed in both zones. About 2,550 wells were operating in the San Juan Basin in 2001 (CO Oil and Gas Conservation Commission and NM Oil Conservation Division, 2001). All wells are vertical wells that range from about 500 to 4,000 feet in depth, and were drilled using water or water-based muds. Almost every well has been fracture-stimulated, using either conventional hydraulic fracturing in perforated casing or cavitation cycling in open holes (Palmer et al., 1993b). Total gas production was 925 Bcf in 2000 (GTI, 2002).

Cavitation cycling is a fracturing method unique to a small area of the north-central San Juan Basin called the "Sweet Spot," or Fairway, of Area 1 (Figure A1-15). Almost half of all San Juan wells are located within the Fairway area and utilize open-hole completions (no casing across the production interval) and cavitation cycling. Cavitation cycling is used in this area because coals are: 1) very thick (individual coals over 40 feet thick); 2) hydrostatically over-pressured (0.5 to 0.7 pounds per square inch per foot); and 3) relatively more permeable than the rest of the basin (and coals in other basins) (Palmer et al., 1993b). This method uses several mechanisms to link the wellbore to the coal fracture system. Cavitation cycling:

- Creates a physical cavity in the coals of the open-hole section (up to 10 feet in diameter);

- Propagates a self-propping, vertical, tensile fracture that extends up to 200 feet away from the wellbore (parallel to the direction of least stress); and

- Creates a zone of shear stress-failure that enhances permeability in a direction perpendicular to the direction of least stress (Palmer et al., 1993a; Khodaverian and McLennan, 1993) (Figure A1-16).

Cavitation is accomplished by applying pressure to the well using compressed air or foam, and then abruptly releasing the pressure. The over-pressured coal zones provide a pressure surge into the wellbore (a "controlled blowout"), and the resulting stress causes dislodgement of coal chips and carries the chips up the well. These cycles of pressure and blowdown are repeated many times over a period of hours or days, and the repeated, alternating stress-shear failure in the coal formation creates effects that extend laterally from the wellbore (Kahil and Masszi, 1984). The resulting vertical fracture is tensile in origin, that is, it results from a "pulling" force rather than the compressive forces that create conventional hydraulic fractures. Because the fracture is tensile in origin, the height of the fracture does not usually extend out of the target coal seam (Logan et al., 1989).

Wells outside the Fairway area utilize cased-hole, perforated completions that employ conventional hydraulic fracturing (Holditch, 1990). Palmer et al. (1993a) reported that hydraulic fracturing in the San Juan Basin uses between 55,000 to 300,000 gallons of stimulation and fracturing fluids and between 100,000 to 220,000 pounds of sand proppant. In the San Juan Basin, geologic conditions in conjunction with fracturing techniques usually produce vertical fractures much longer than they are high, for example, up to 400 feet radially and less than 150 feet high (e.g., Colorado 32-7 No. 9 well, La Plata County, CO; Mavor et al., 1991). The primary reasons for the controlled height of San Juan coalbed fractures are the thickness and close spacing of coal seams (obviating the need for excessive height), and the presence and petro-physical properties of the overlying Kirtland shale (which prevents inadvertent fracture excursion out of the Fruitland) (Jeu et al., 1988; Logan et al., 1989; Palmer and Kutas, 1991). Holditch (1993) reports that where the coal seam is not overlain by shale, hydraulic fractures in the San Juan Basin can grow into overlying beds.

Fassett (1991) found that coalbed methane could migrate into overlying USDWs near the northern outcrop, in areas where confining shale layers are absent. Because of these factors, hydraulic fracturing in the San Juan Basin may indirectly impact overlying USDWs near the Fruitland outcrop at the basin margins, where USDWs are in closer proximity and the Kirtland shale may be eroded. Near the northern and northwestern recharge zones, groundwater usually contains less than 3,000 mg/L TDS (Kaiser et al., 1994; Cox et al., 1995).

Fracturing and stimulation fluids utilized in the northern San Juan Basin include (Figure A1-17 and Table A1-1):

- Hydrochloric acid (12% to 28% HCl);
- Plain water;
- Slick water (water mixed with solvent);
- Linear gels (water and a thickener such as guar-gum or a polymer);
- Cross-linked gels with breakers (gels with additives to prevent fluid leak-off from the fracture, and "breaker" chemicals to reduce viscosity so that the gel can be produced back from the well after treatment); and
- Nitrogen and CO_2 foam (75 percent gas, 25 percent water or slick water, plus a foaming agent) since about 1992 (Harper et al., 1985; Jeu et al., 1988; Holditch et al., 1989; Palmer et al., 1993a; Choate et al., 1993)

Oilfield service companies supply the stimulation fluid used to fracture the well as part of the service. The chemical composition of many fracturing fluids may be proprietary, and EPA was unable to find complete chemical analyses of any fracturing fluids in the literature. Table A1-1 presents some data from the literature concerning the general chemical makeup of common San Juan fracturing fluids (Economides and Nolte, 1989; Penny et al., 1991). In addition, most gel fluids utilize a breaker compound (usually borate or persulfate compounds or an enzyme, at 2 pounds/1,000 gallons) to allow post-treatment thinning and easier recovery of gels from the fracture (e.g., Jeu et al., 1988; Palmer et al., 1993a; Pashin and Hinkle, 1997).

Many of the compounds listed in Table A1-1 are quite hazardous in their undiluted form. However, these compounds are substantially diluted prior to injection. Coalbed methane development by fracturing, and stimulation in the San Juan Basin are regulated by the Colorado Oil and Gas Conservation Commission and the New Mexico Oil and Gas Board. Based on an analysis of current regulations, neither agency regulates the type or amount of fluids used for fracturing (Colorado State Oil and Gas Board Rules and Regulations 400-3, 2001; New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division Regulations Title 19, Chapter 15, 2001).

About half of the coalbed methane wells in Area 1 are located in the Fairway zone and feature "cavitation-cycling" completions (Palmer et al., 1993a) (Figure A1-15). Therefore, about half of the wells in Area 1 have probably been stimulated using conventional fracture treatments. Based on the well density of Area 1 in 1990 (Figure A1-18) compared to the 2001 well population (2,550 wells), it is estimated that between 700 and 1,000 coalbed methane wells have been fracture-stimulated in the USDW of Area 1.

It has been shown that methane can migrate from gas wells into aquifers along the northern margin of the basin, but this condition was remediated with improved gas well construction (Cox et al., 1995). In addition, wells completed in other aquifers in the outcrop area have been shown to produce water chemically and isotopically similar to Fruitland wells, implying communication between the formations (Cox et al., 1995).

1.4 Summary

Coalbed methane development and hydraulic fracturing in some of the northern portions of the San Juan Basin take place within a USDW. The waters of the Fruitland-upper Picture Cliffs aquifer and producing zone in Area 1 usually contain less than 10,000 mg/L TDS. Most waters in the northern half of Area 1 contain less than 3,000 mg/L, and wells near the outcrop produce water that contains less than 500 mg/L.

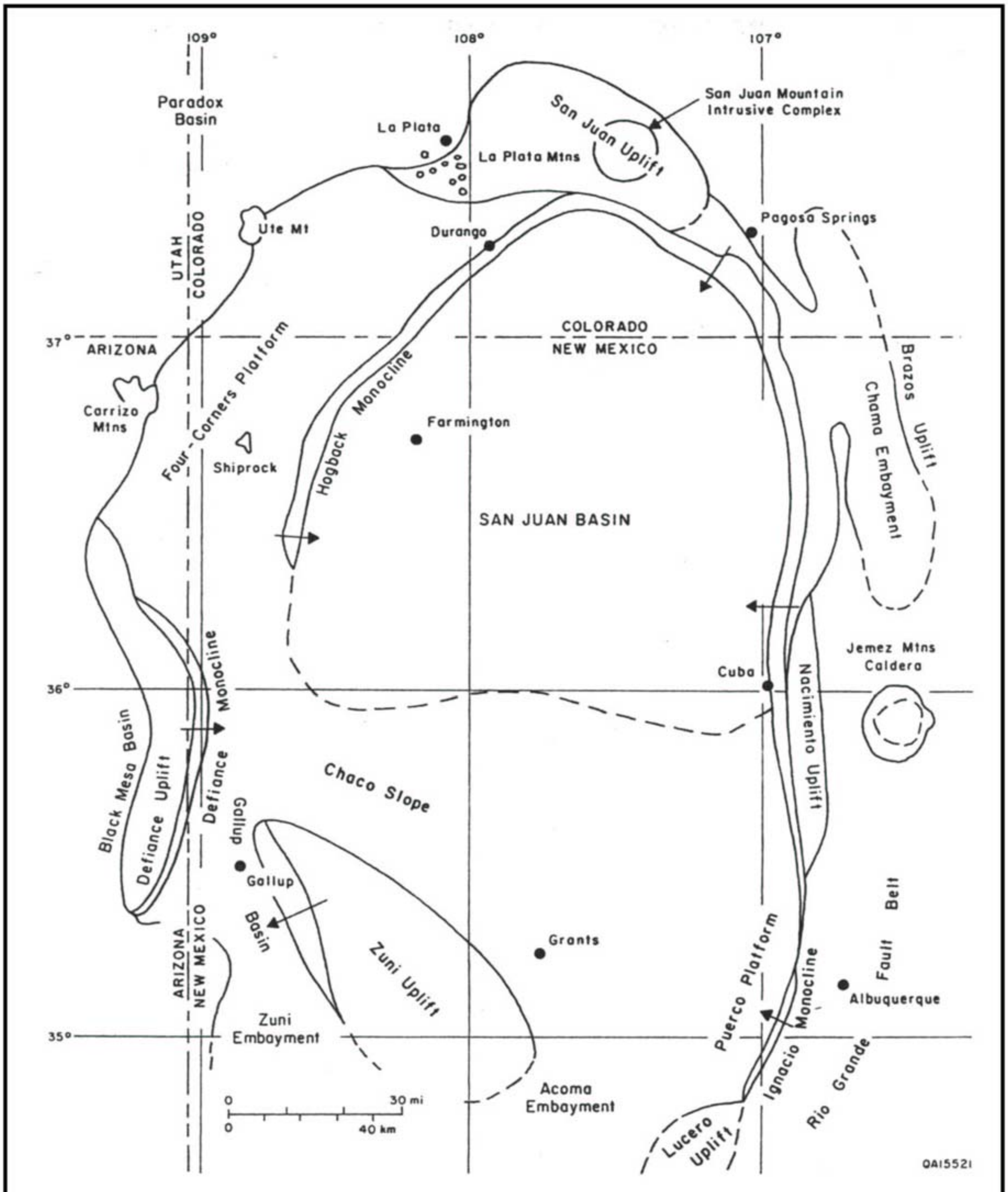
Each fracture stimulation treatment may inject, on average, approximately 55,000 to 300,000 gallons of stimulation and fracturing fluid per treatment. There are no state controls on the type, composition, or volume of fracturing fluid employed in each well or treatment. In contrast to conventional gas formations, the anisotropic nature of fracture permeability, the volume of treatment fluids employed, and the height and proppant distribution in coalbed fractures may prevent the effective recovery of fracturing fluids during subsequent production.

The potential for fracturing to cause or allow degradation of water in aquifers adjacent to the producing zones seems relatively remote in the currently active gas producing fields, but the potential for such degradation varies in different parts of the basin. It has been shown that methane can migrate from gas wells into aquifers along the northern margin of the basin, but this condition was corrected with improved gas well construction. There is little potential for fracturing to create communication between the Fruitland-upper Picture Cliffs aquifer and the Ojo Alamo aquifer over much of the basin because the aquifers are separated by the poorly permeable Kirkland shale. However, the Kirkland varies greatly in thickness and forms a leaky hydrogeologic barrier when it is thinner. In the eastern part of the basin, the Kirkland Formation has been eroded and the Ojo Alamo lies disconformably and directly upon the Fruitland Formation, potentially allowing fracturing to cause hydraulic communication between the saline waters of the Fruitland and the fresh waters (500 to 1,000 mg/L) of the Ojo Alamo.

Table A1-1. Chemical Components of Typical Fracture/Stimulation Fluids Used for San Juan Coalbed Methane Wells

Type of Stimulation Fluid	Composition	pH
Hydrochloric acid	12% to 28% HCl water solution	<1-3
"Slick" water	miscible or immiscible solvent as viscosity reducer (% unknown)	NA
Diesel oil	NA	NA
Nitrogen and CO_2 foam	75 % gas, 25 % water or slick water, plus a foaming agent)	NA
Gels[1]		
R-F	3% resorcinol, 3% formaldehyde, 0.5% KCl, 0.4% $NaHCO_3$	6.5
Pfizer Flocon 4800	0.4% xanthan, 154 ppm Cr^{3+} (as $CrCl_3$), 0.5% KCl	4.0
Marathon MARCIT	1.4% polyacrylamide (HPAM), 636 ppm Cr^{3+} (as acetate), 1% NaCl	6.0
DuPont LuDox SM	10% colloidal silica, 0.7% NaCl	8.2
CPAM crosslinked with Pfizer Floperm 500	0.4% cationic polyacrylamide (CPAM), 1520 ppm glyoxal 2% KCl	7.3
Drilling Specialties HE-100 Crosslinked	0.3% HPAM-AMPS, 100 ppm Cr^{3+} (as acetate), 2% KCl	5.0
Dowell YF-230	Hydroxypropylguar (HPG) x-linked with borate, persulfate with amine	NA

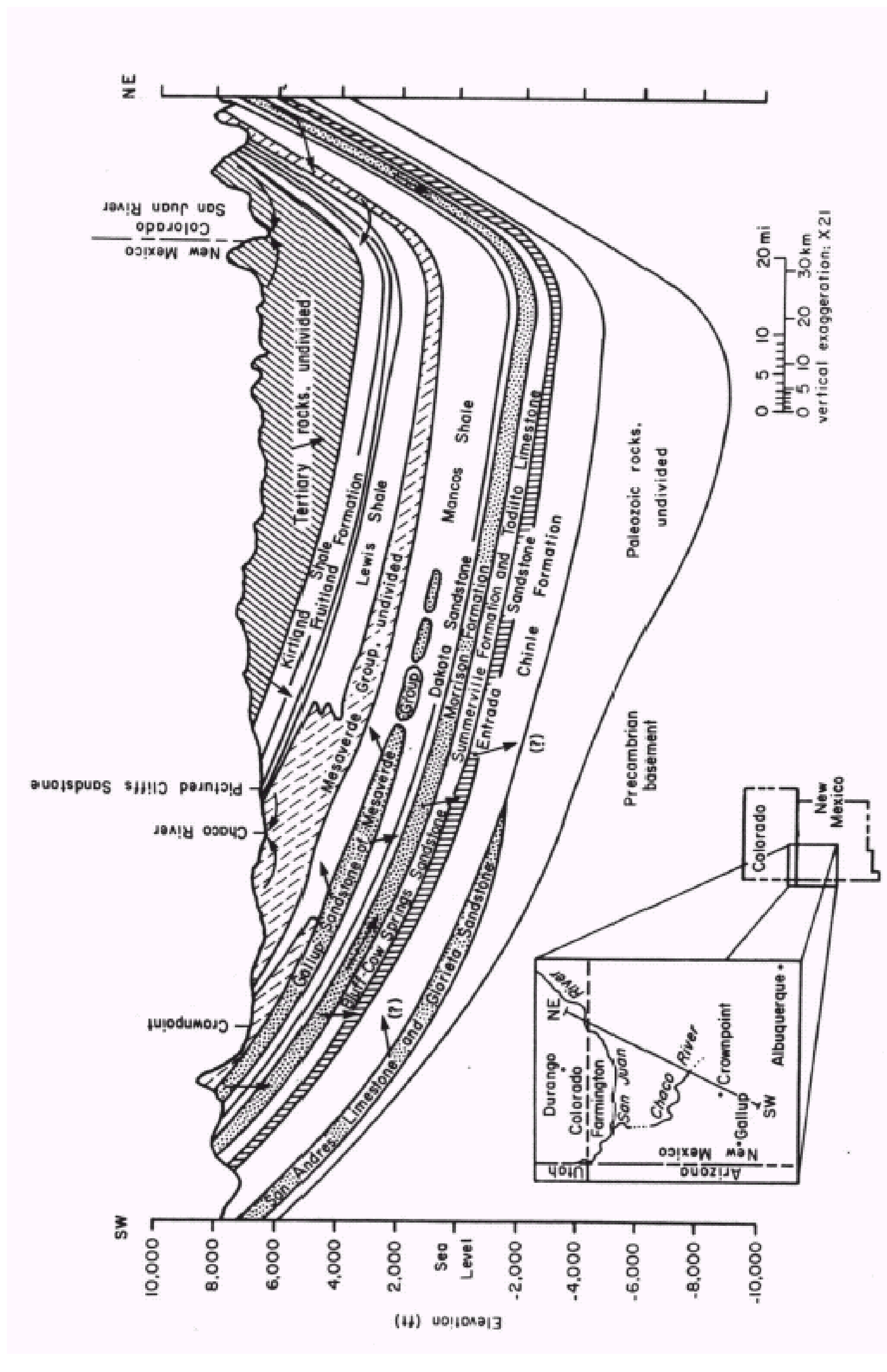
[1] Gels are typically mixed at a ratio of 40 lbs. per 1000 gal. water; compositions shown are "as mixed".



Regional Tectonic Setting of the San Juan Basin
(Laubach & Tremain, 1994)

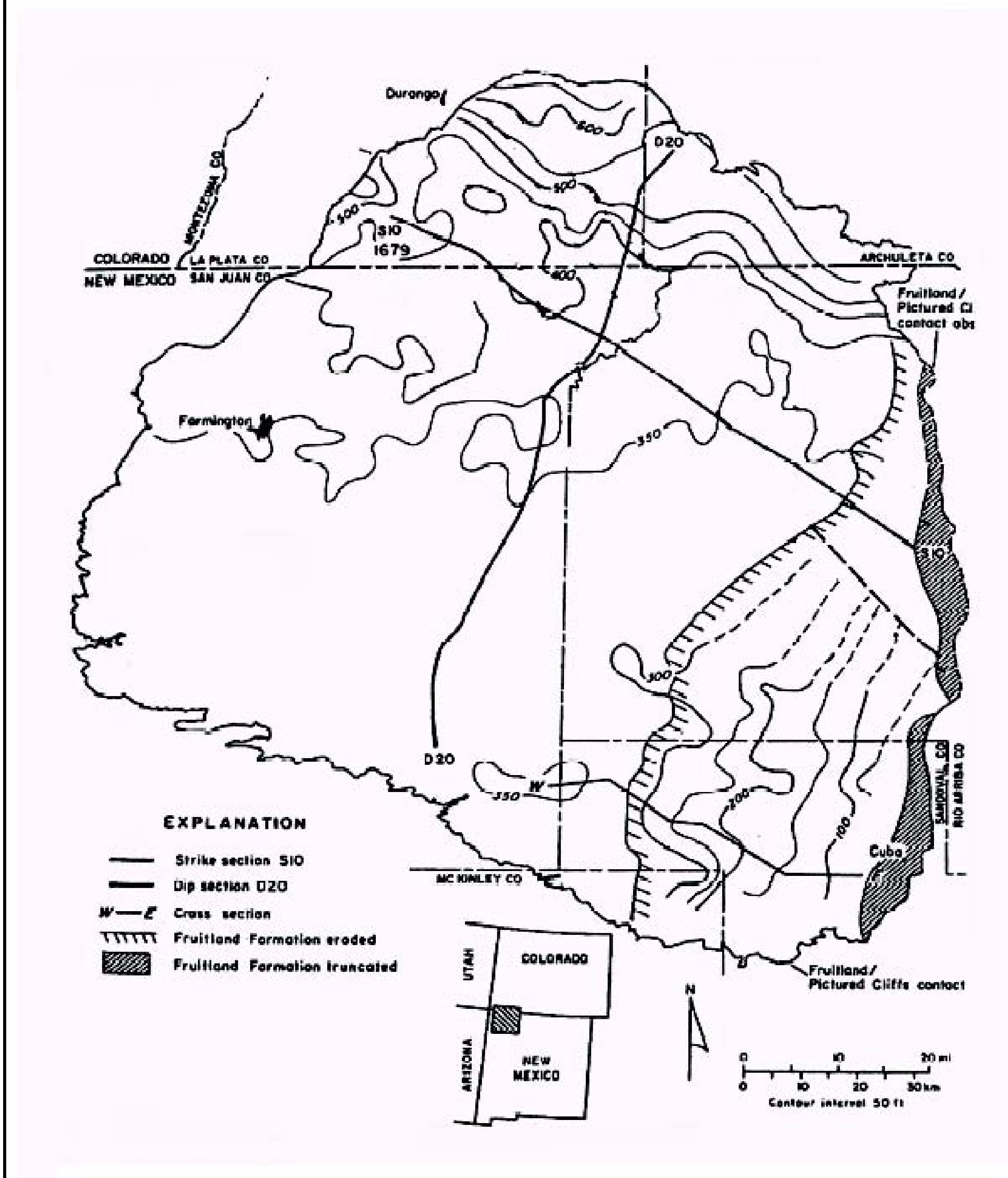
7/14/01 kk 1027-SJ-1.cdr

Figure A1-1



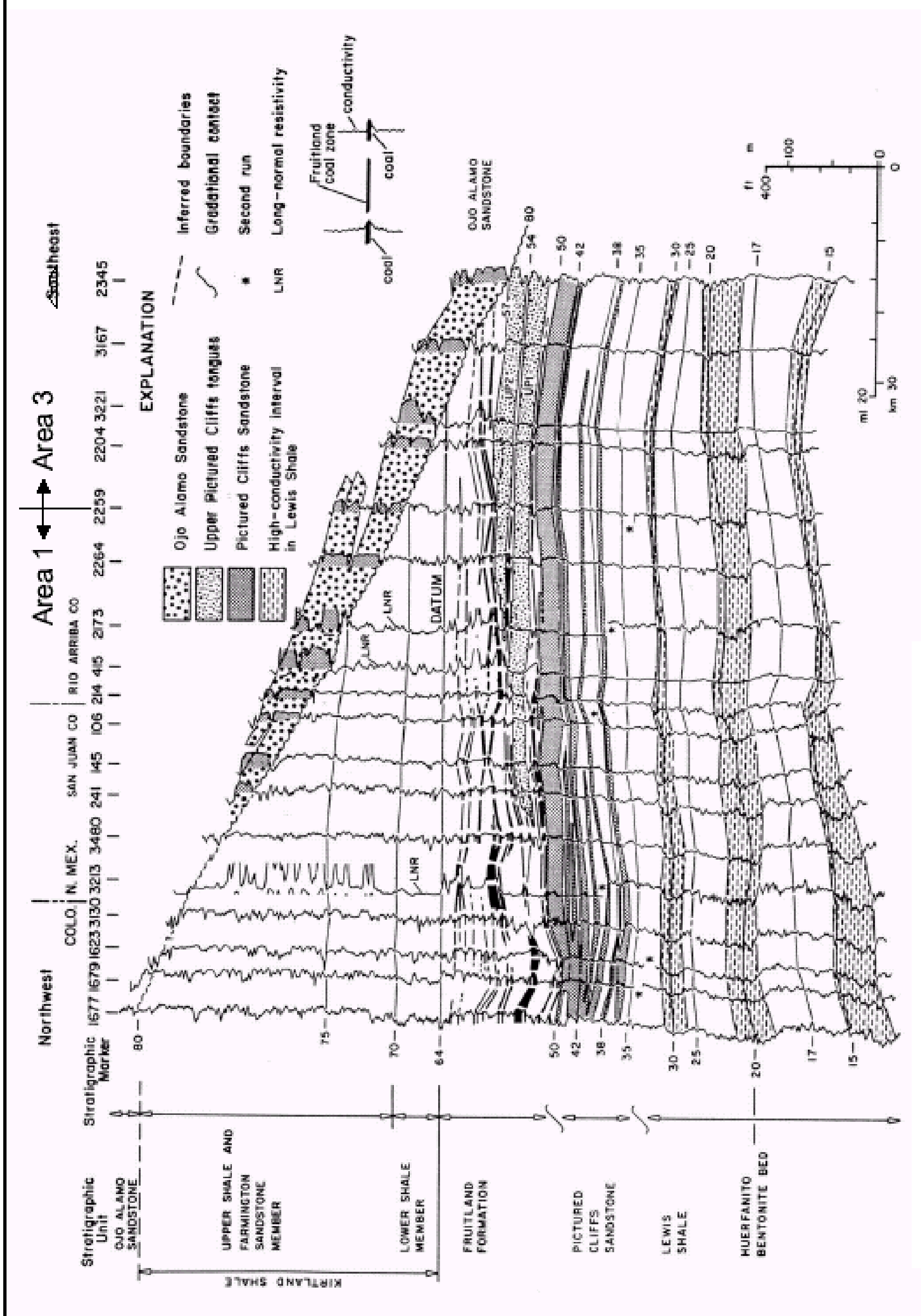
Generalized Hydrogeologic Cross-Section of the San Juan Basin (Stone et al., 1983)

Figure A1-2



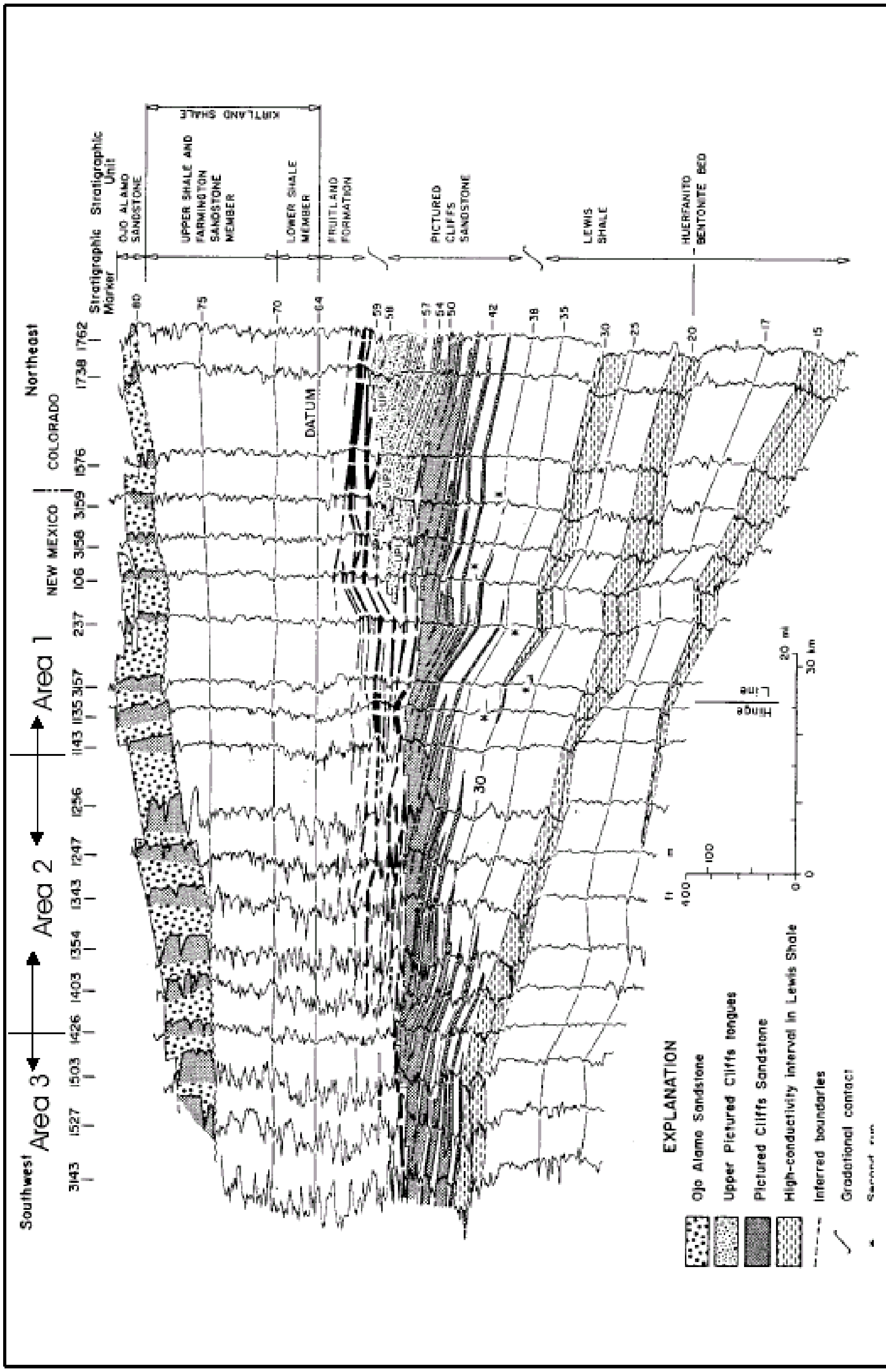
Isopach Map of the Fruitland Formation Including Pictured Cliffs Tongues.
Cross Sections S10, D20 and E-W are shown in Figures A1-4, A1-5 and A1-6
(Ayers and Ambrose, 1990)

7/14/01 kk 1027-SJ-3.cdr | Figure A1-3



Cross Section S-10 from Figure A1-3, a Stratigraphic Strike Section (Ayers and Ambrose, 1990)

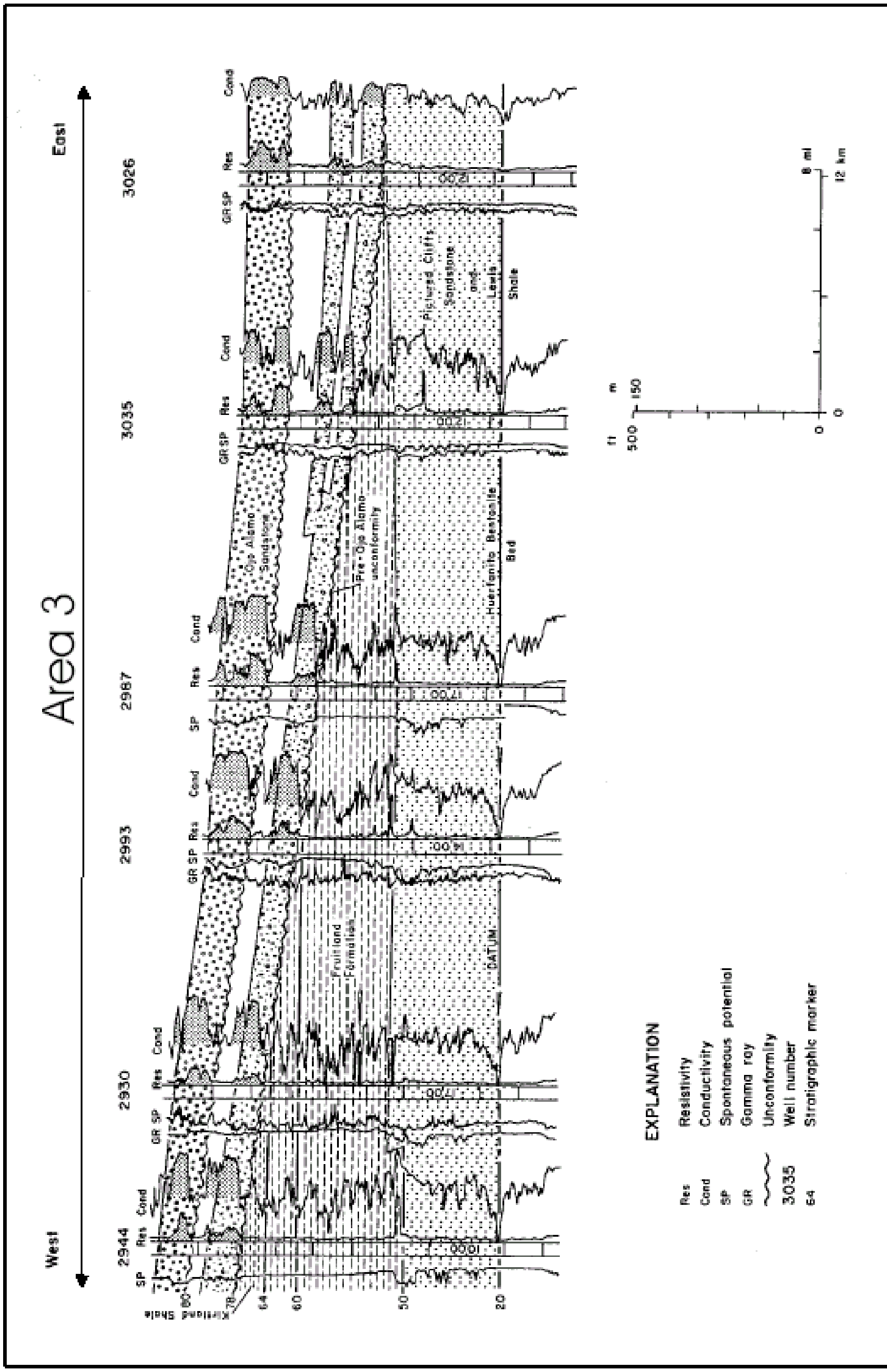
Figure A1-4



Cross Section D-20 from Figure A1-3, a Stratigraphic Dip Section from the Fruitland to the Ojo Alamo (Ayers and Ambrose, 1990)

7/14/01 kk 1027-SJ-5...cdr

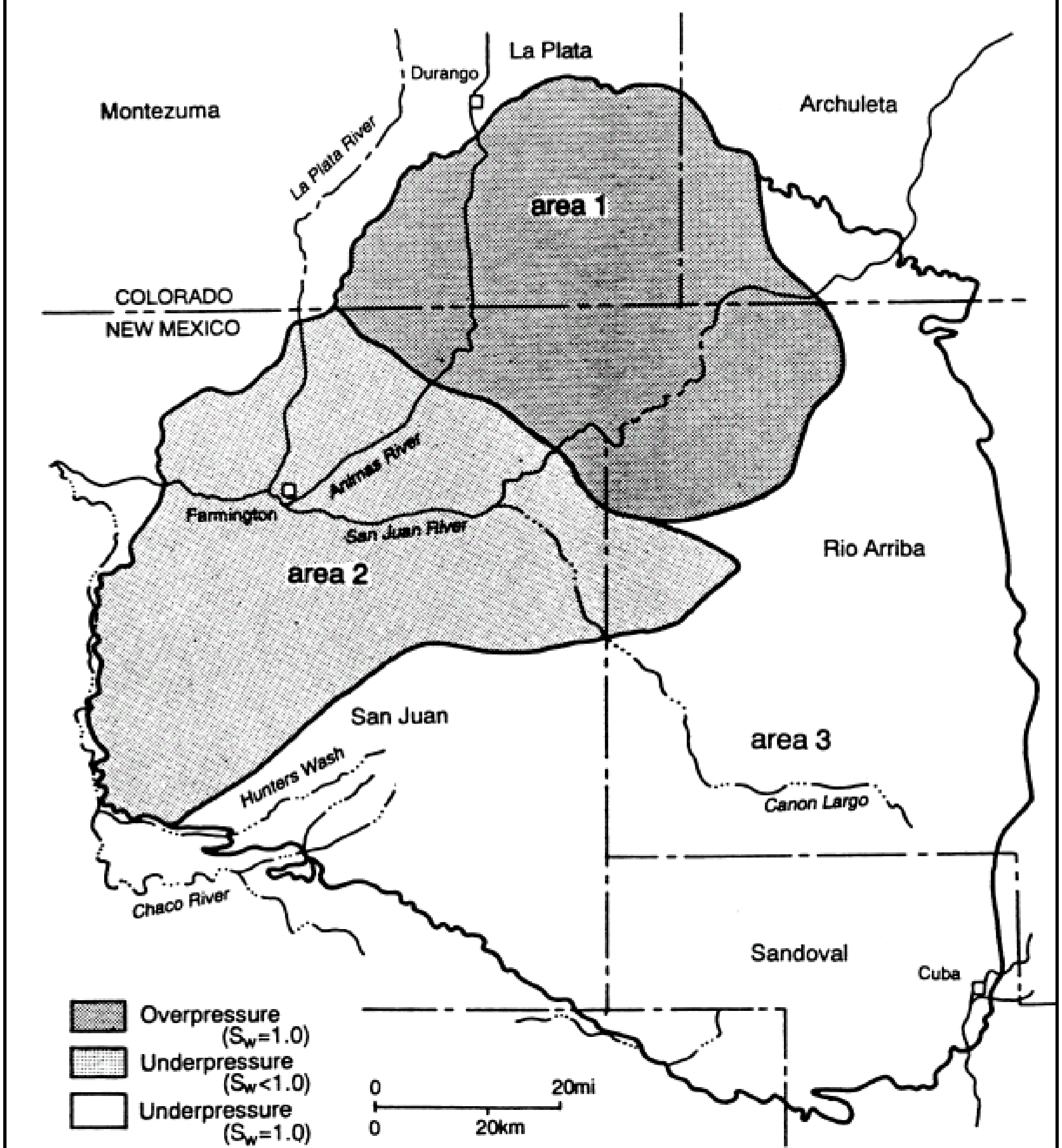
Figure A1-5



Cross Section E-W from Figure A1-3, a Stratigraphic Strike Section from the Southeastern San Juan Basin, Showing the Erosional Fruitland-Ojo Alamo Contact

The Kirtland Shale has been eroded and the Ojo Alamo rests unconformably on the Fruitland (Ayers and Ambrose, 1990)

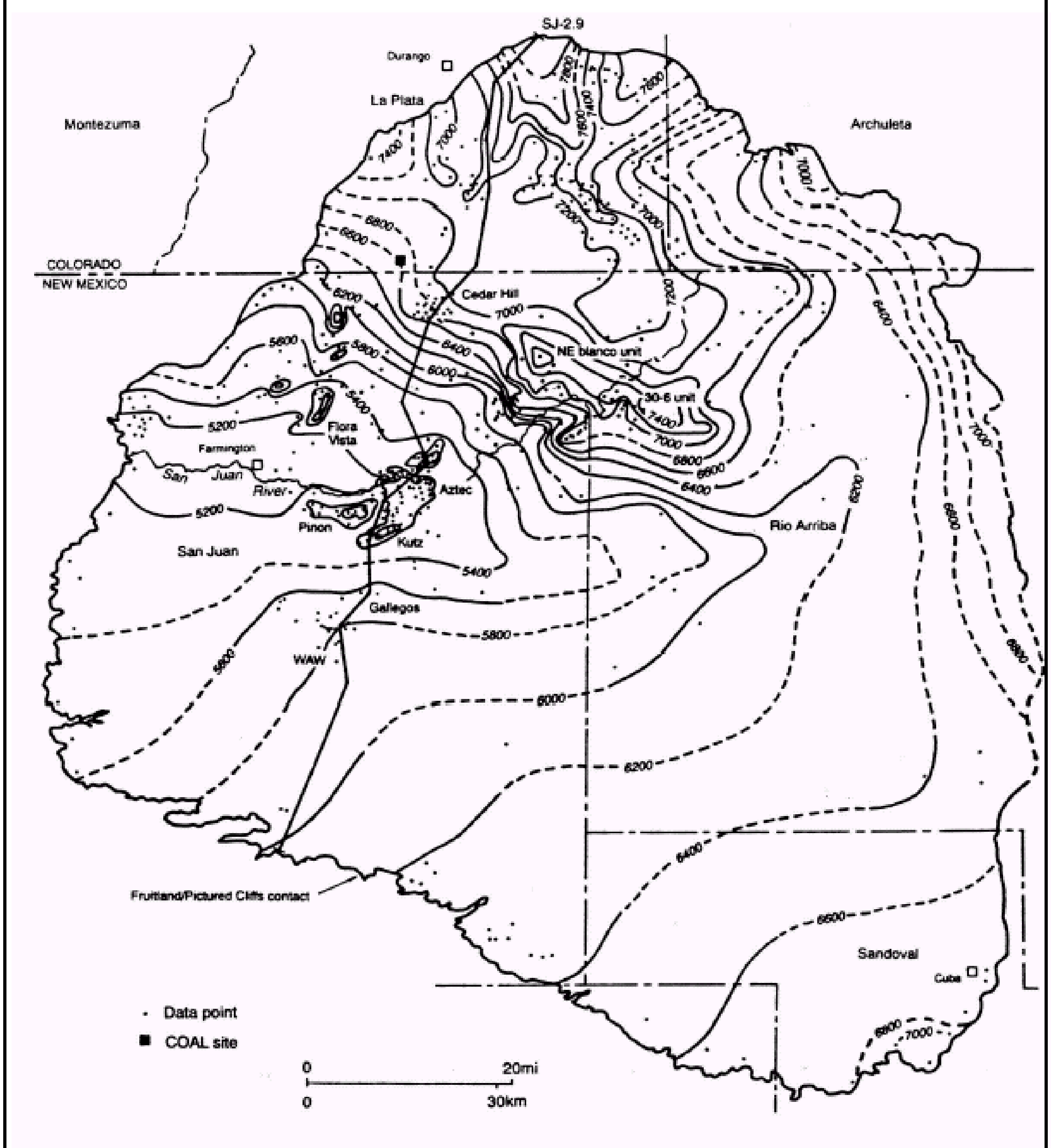
Figure A1-6



Areas of the San Juan Basin that Exhibit Similar Characteristics for Production, Coal Properties, and Hydrologic Pressure (New Mexico Bureau of Mines and Minerals, 1993)

7/14/01 kk 1027-SJ7.cdr

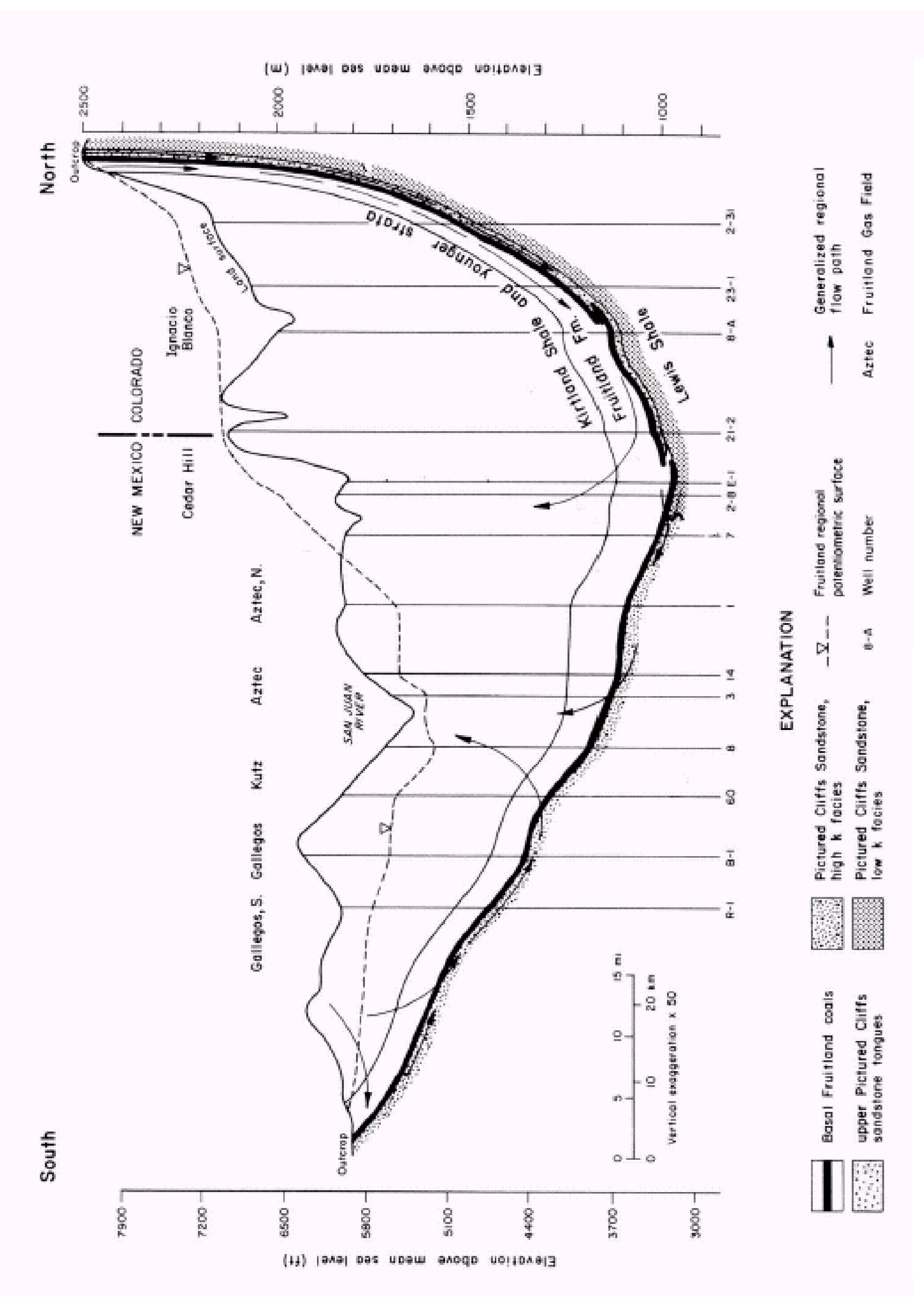
Figure A1-7



Map of the Potentiometric Surface of the Fruitland Aquifer (Kaiser et al., 1994)

7/14/01 kk 1027-SJ-08.cdr

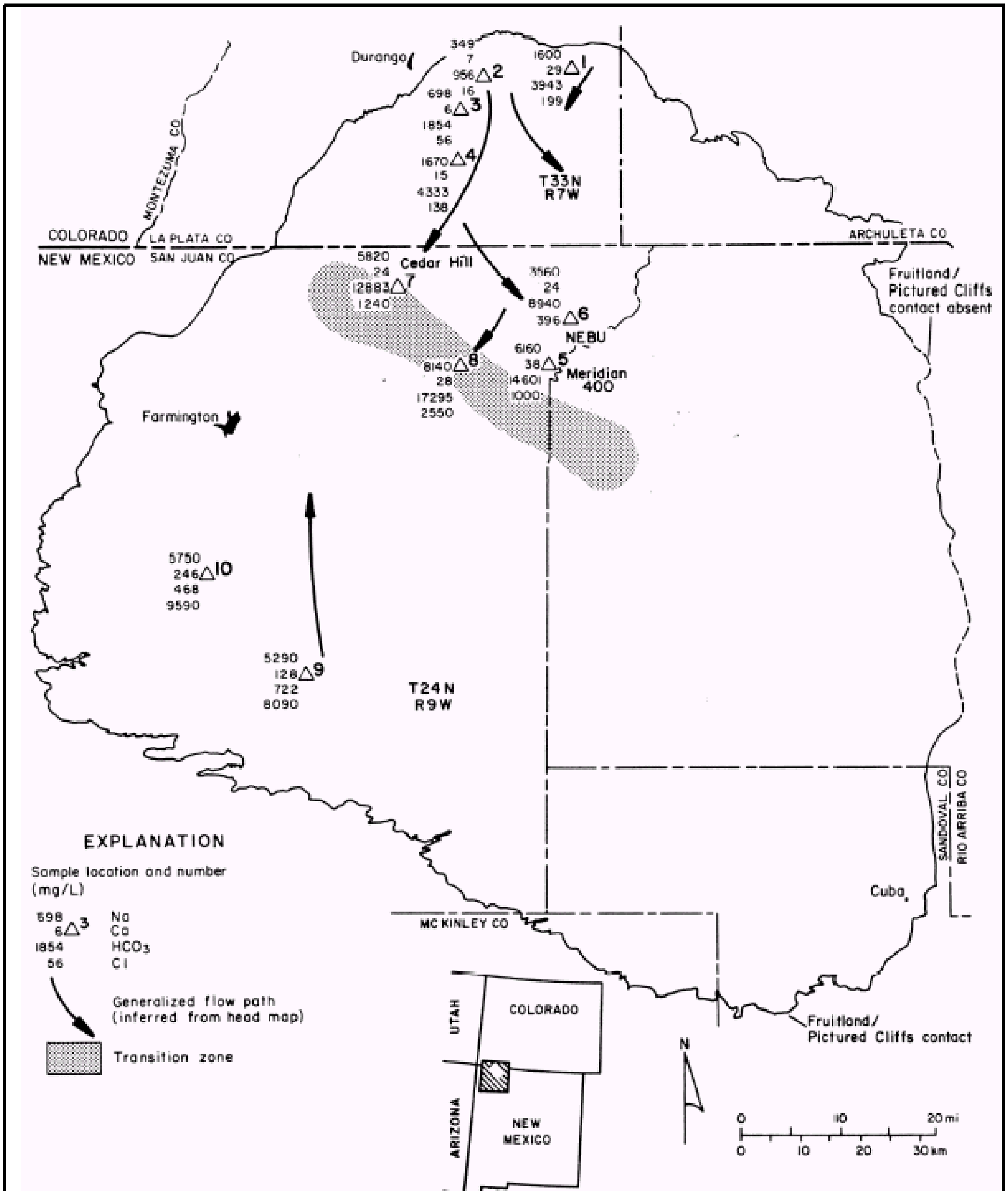
Figure A1-8



General Ground Water Flow in the Fruitland/Pictured Cliffs Aquifer System, San Juan Basin (Kaiser and Swartz, 1988)

7/14/01 kk 1027-SJ-09.cdr

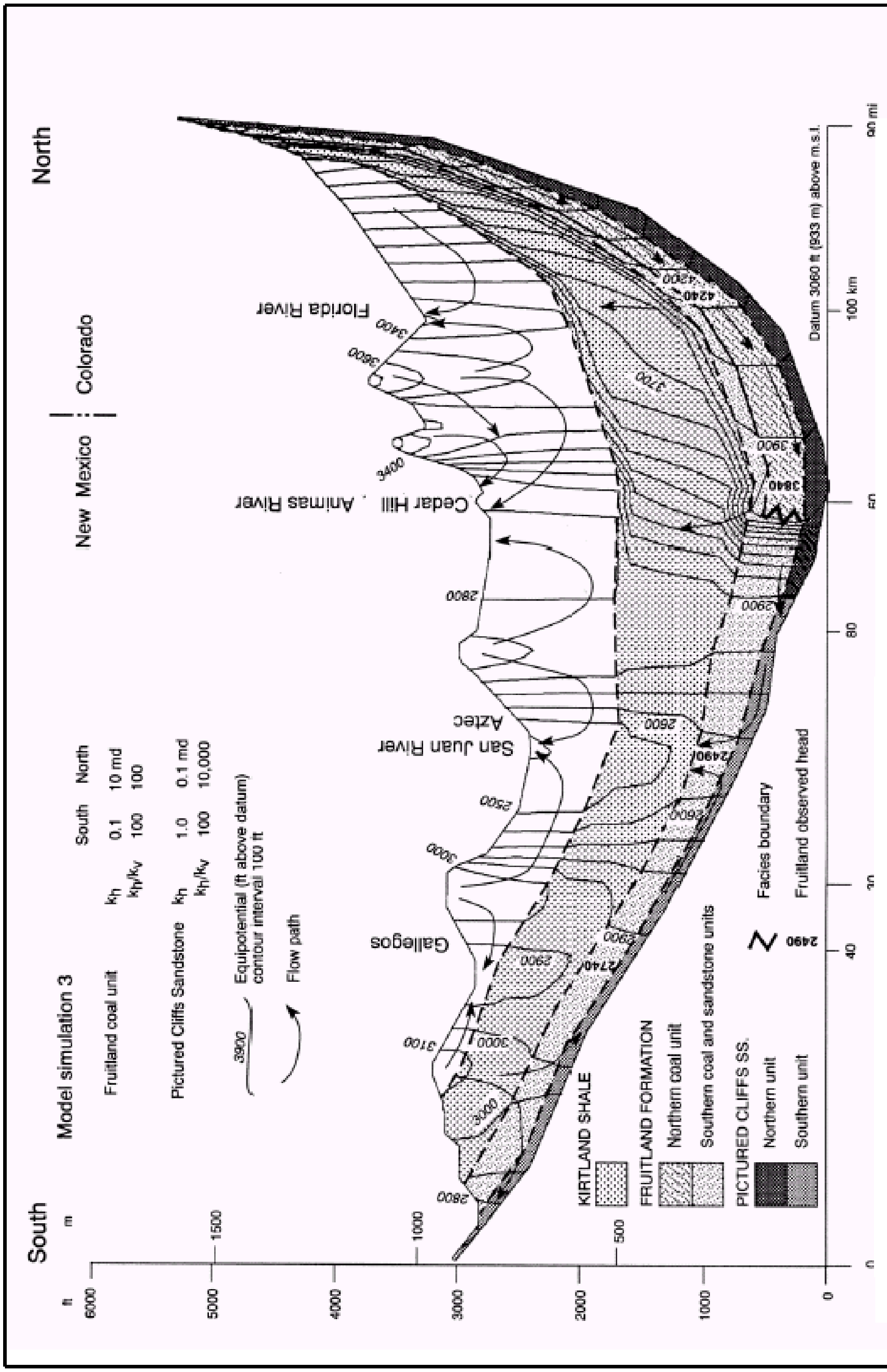
Figure A1-9



Generalized Flow Paths of the Fruitland/Pictured Cliffs Aquifer System, San Juan Basin (Kaiser et al., 1994)

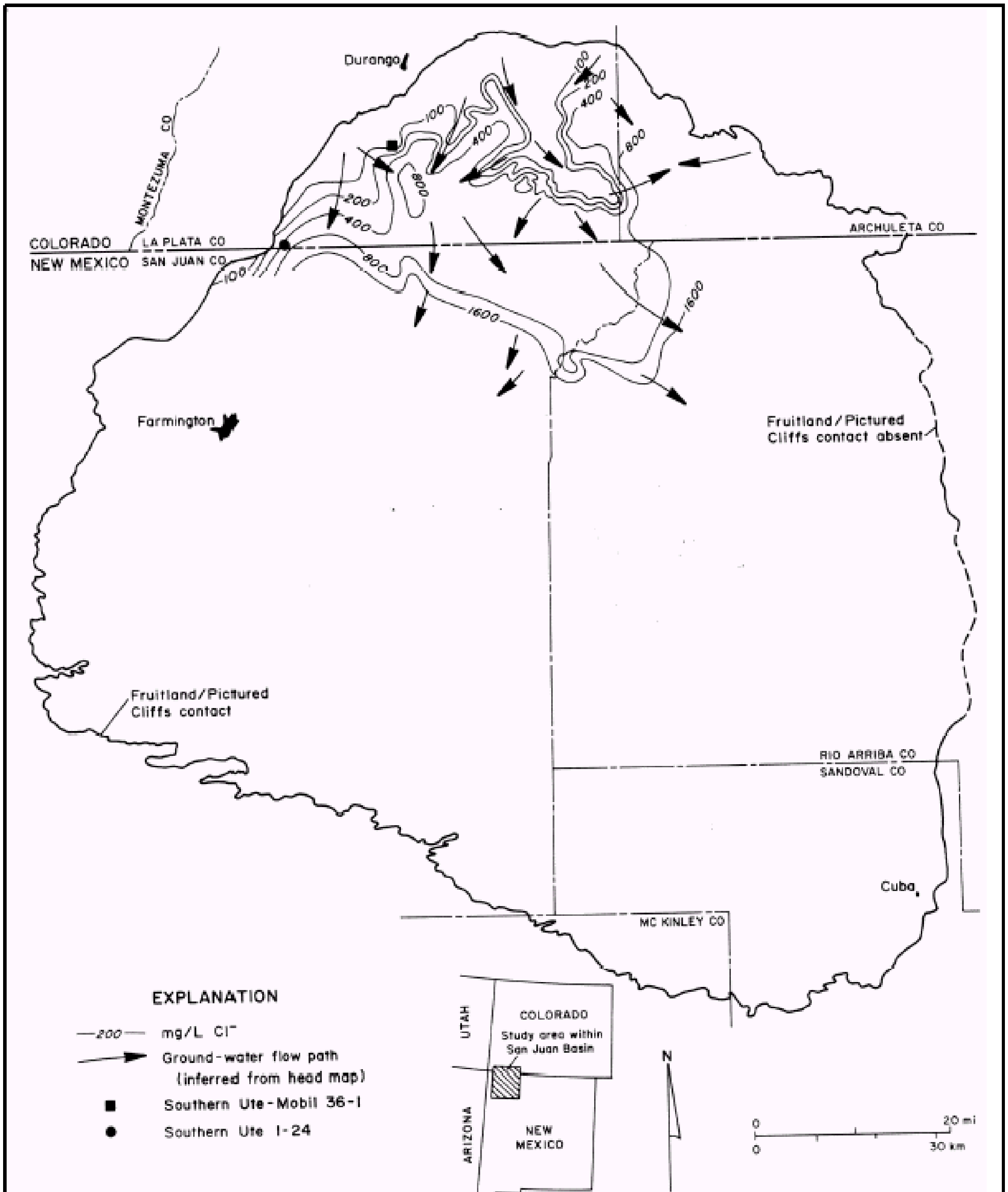
7/14/01 kk 1027-SJ-10.cdr

Figure A1-10



Equipotentials and Flow Paths from Ground Water Flow Modeling of the San Juan Basin
(Kaiser et al., 1994)

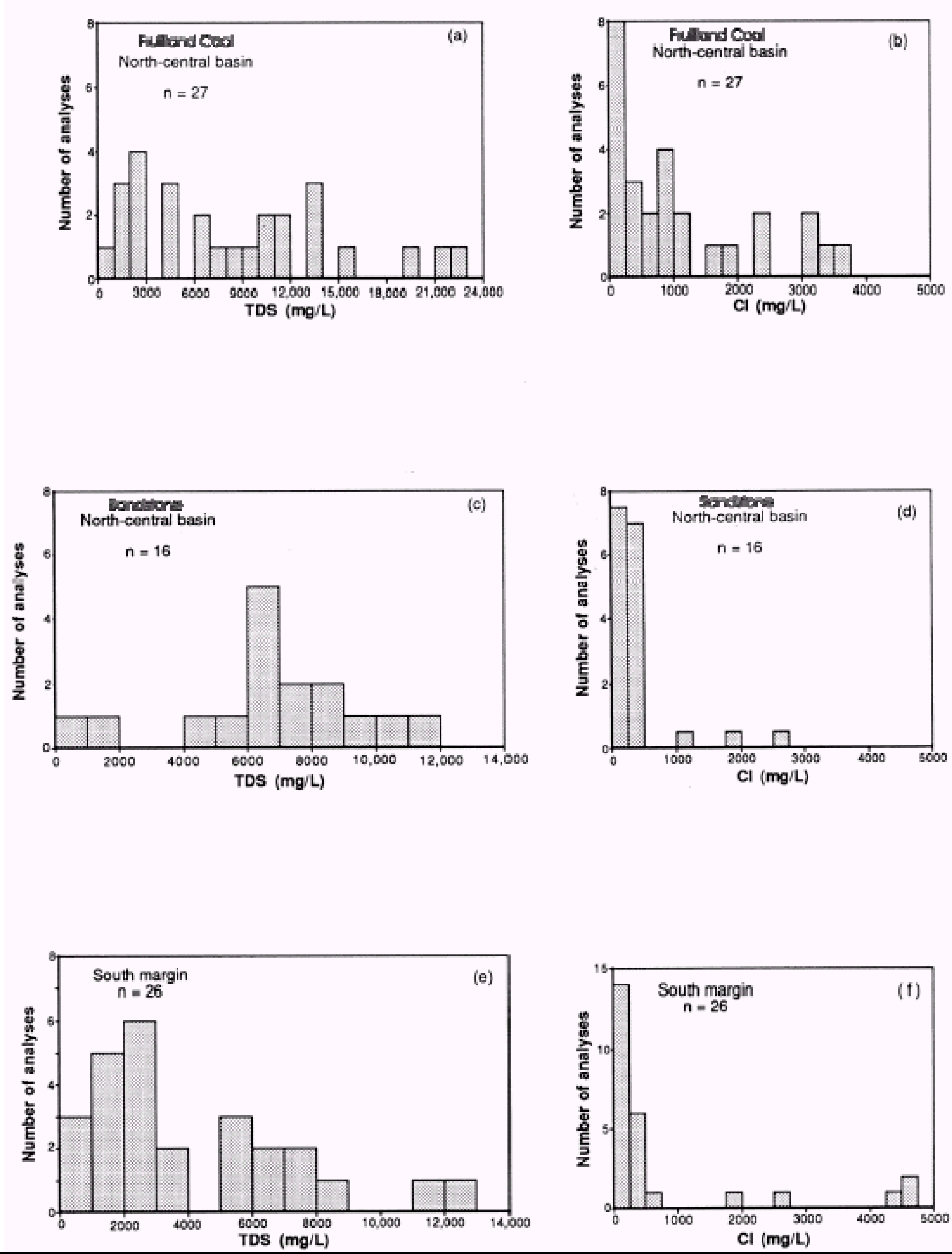
Figure A1-11



Chloride Concentration Map (mg/L) of Waters of the Fruitland Aquifer, San Juan Basin (Kaiser and Swartz, 1988)

7/14/01 kk 1027-SJ-12.cdr

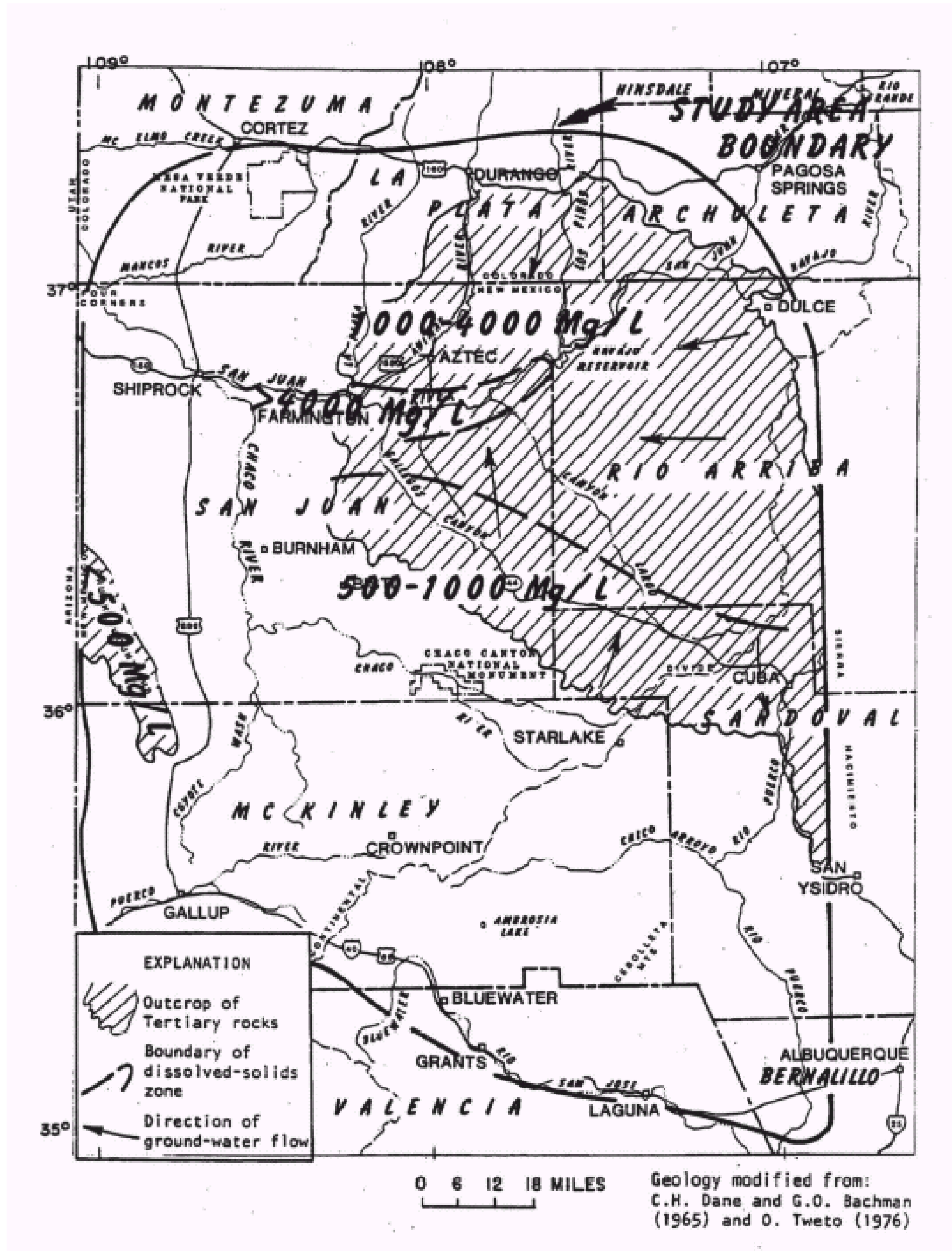
Figure A1-12



Histograms of Water Analyses (mg/L) from the Fruitland/Pictured Cliffs Aquifer System in the North Central and South-Margin Areas of the San Juan Basin
(Kaiser and Swartz, 1994)

7/14/01 kk 1027-SJ-13.cdr

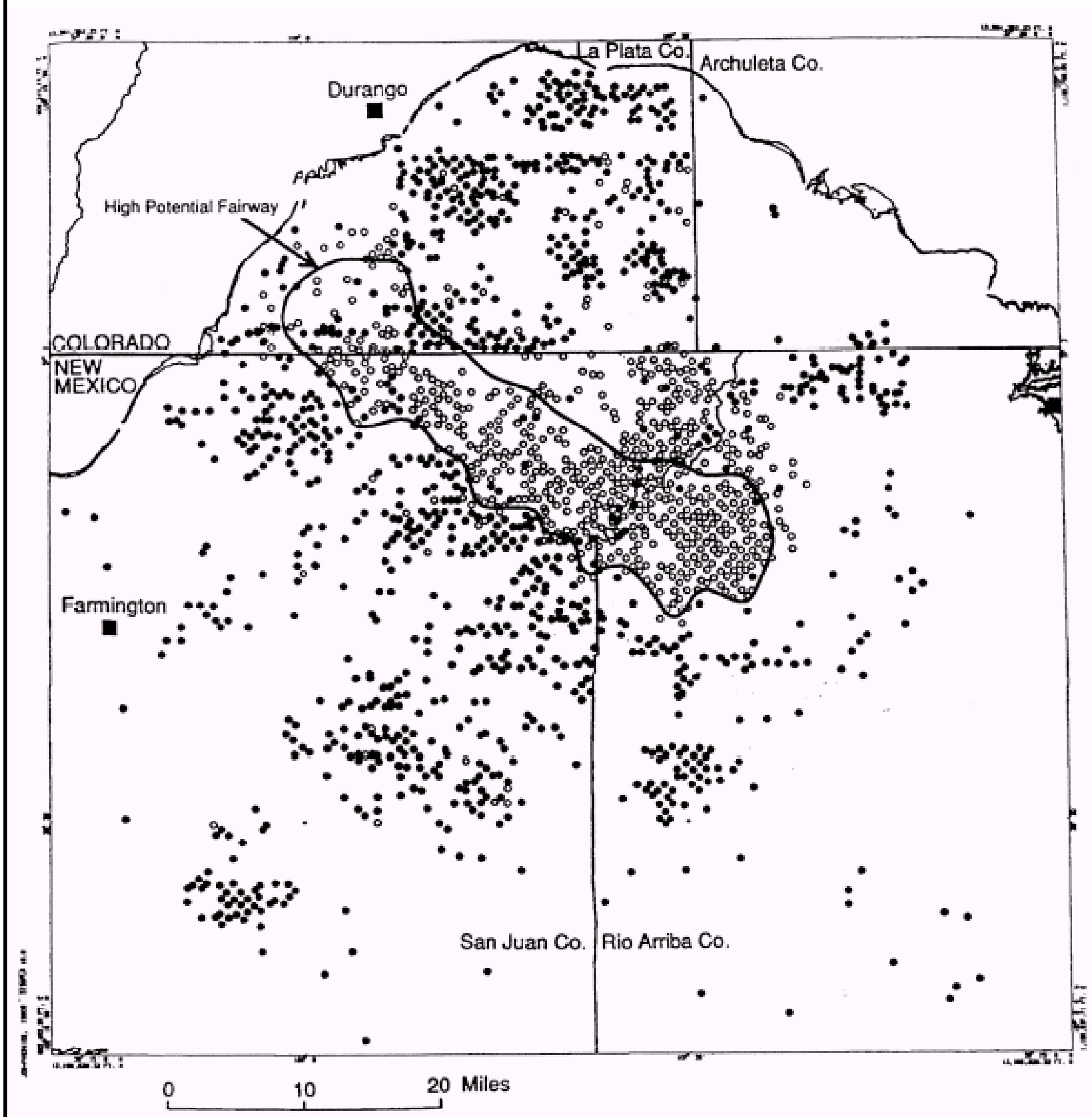
Figure A1-13



Direction of Ground Water Flow and Dissolved Solids Concentration in Tertiary Rocks (Lyford, 1979)

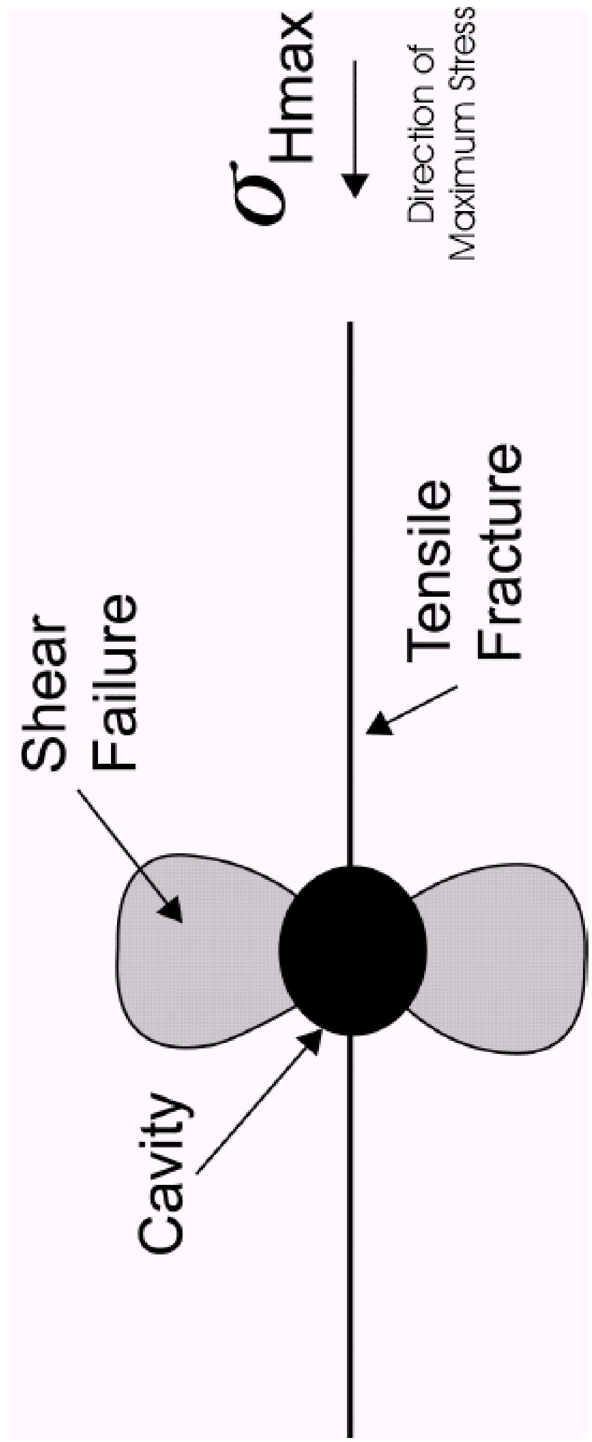
7/14/01 kk 1027-SJ-14.cdr

Figure A1-14



Outline of the Fairway Zone of Area 1 of the San Juan Basin
Filled dots represents wells using conventional fracturing treatments, and empty dots represent cavitation-cycling completions
(Palmer et al., 1993)

7/14/01 kk 1027-SJ-15.cdr | Figure A1-15



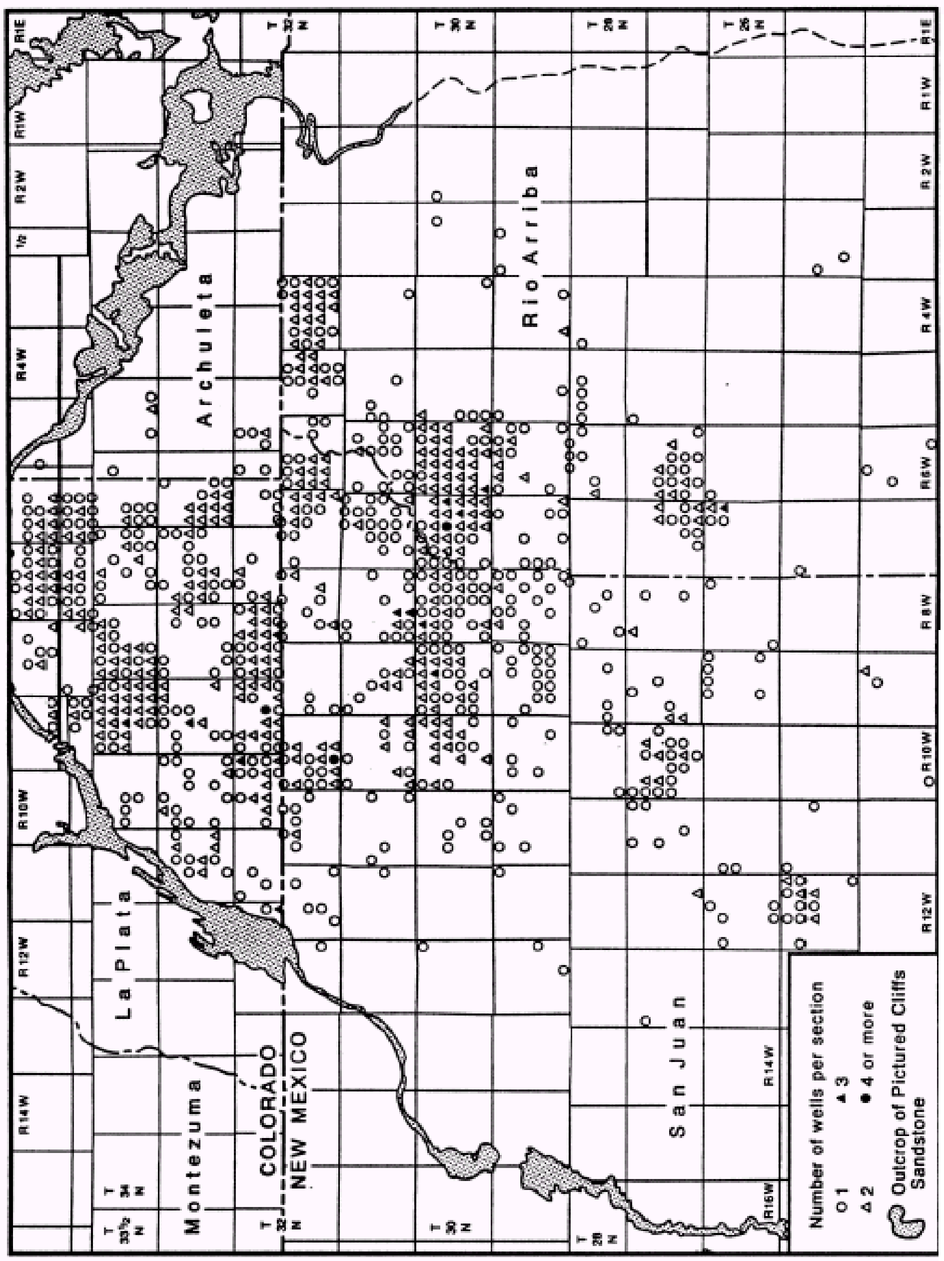
Conceptual Schematic (Plan View) of Tensile Fracture and Shear Failure in Coal Formed by Openhole Cavitation Cycling (Khodaverian and McLennan, 1993)

Figure A1-16

Cross-linked Gelled Sand Frac	
Water volume	2500 gal/ft of pay
Sand volume	5000 lbs/ft of pay
Type fluid	30# borate cross-linked gel
Type sand	40/70 mesh (1st 10% of job for fluid loss) 12/20 mesh (thereafter)
Avg. injection rate	55 BPM
Max. sand concentration	12 ppg
Pad volume	35% of total fluid pumped
Cost	$50M–$60M
Slick Water Sand Frac	
Water volume	4500 gal/ft of pay
Sand volume	3500 lbs/ft of pay
Type fluid	fresh water w/friction reducer
Type sand	20/40 mesh
Avg. injection rate	100 bpm
Max. sand concentration	6 ppg
Pad volume	66% of total fluid pumped
Cost	$25M–$35M
Foam Frac (gelled water)	
Water volume	2000 gal/ft of pay
Sand volume	5000 lbs/ft of pay
Type fluid	30# borate cross-linked gel
Type sand	100 mesh (1st 14% of job for fluid loss) 12/20 mesh (thereafter)
Avg. injection rate	40 BPM
Max. sand concentration	6 ppg
Pad volume	27% of total fluid pumped
Cost	$100M–$110M
Foam Frac (slick water)	
Water volume	2650 gal/ft of pay
Sand volume	3200 lbs/ft of pay
Type fluid	fresh water w/friction reducer
Type sand	40/70 mesh (1st 10% of job for fluid loss) 20/40 mesh (thereafter)
Avg. injection rate	90 BPM
Max. sand concentration	6 ppg
Pad volume	64% of total fluid pumped
Cost	$75M–$85M

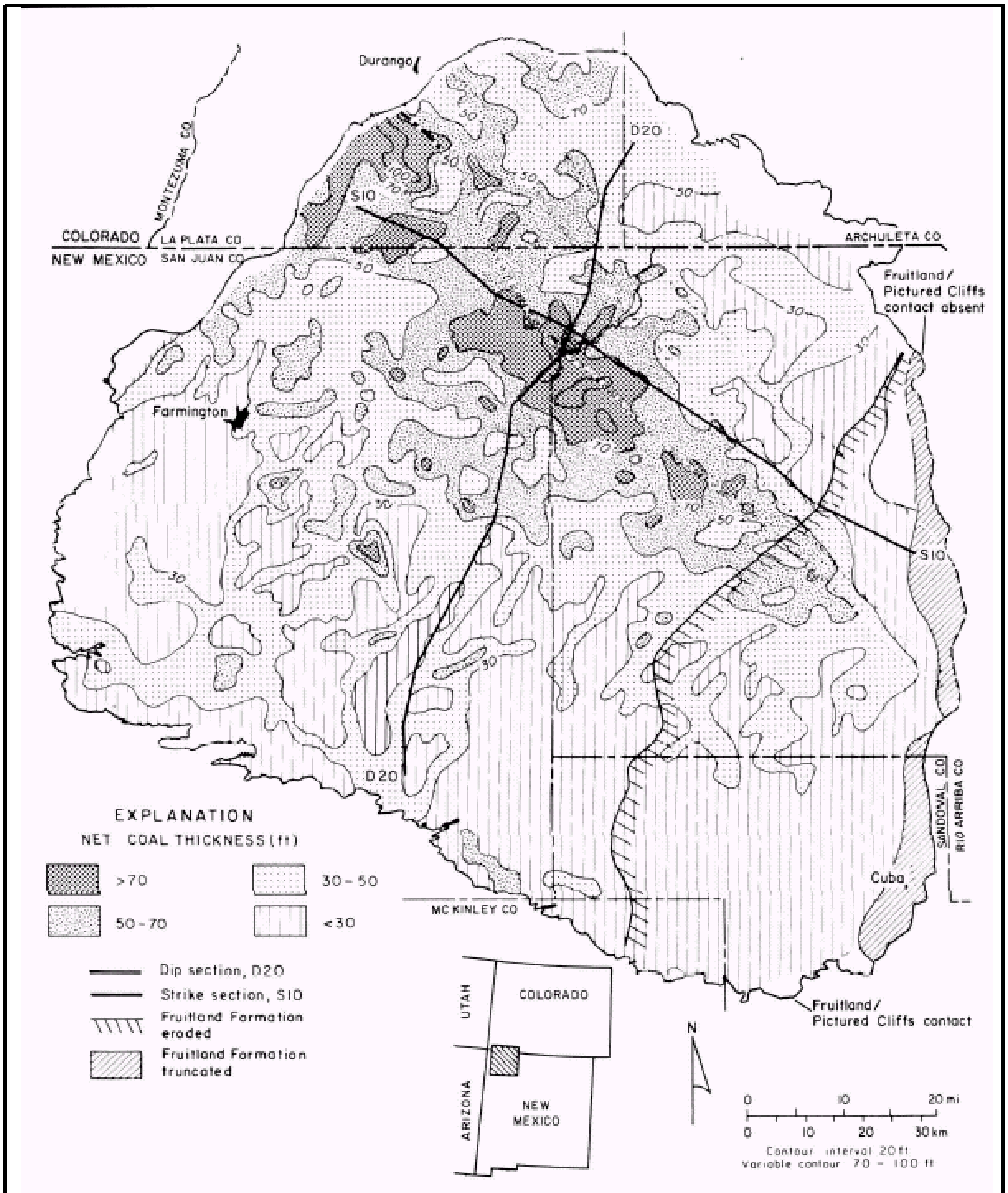
Table of Fracture Stimulation Treatments in the Fruitland Formation of the San Juan Basin (Palmer et al., 1993)

7/14/01 kk 1027-SJ-17.cdr Figure A1-17



Density of Wells in the Northern Portion of Area 1 in the San Juan Basin, as of 12/31/1990
(New Mexico Bureau of Mines, 1993)

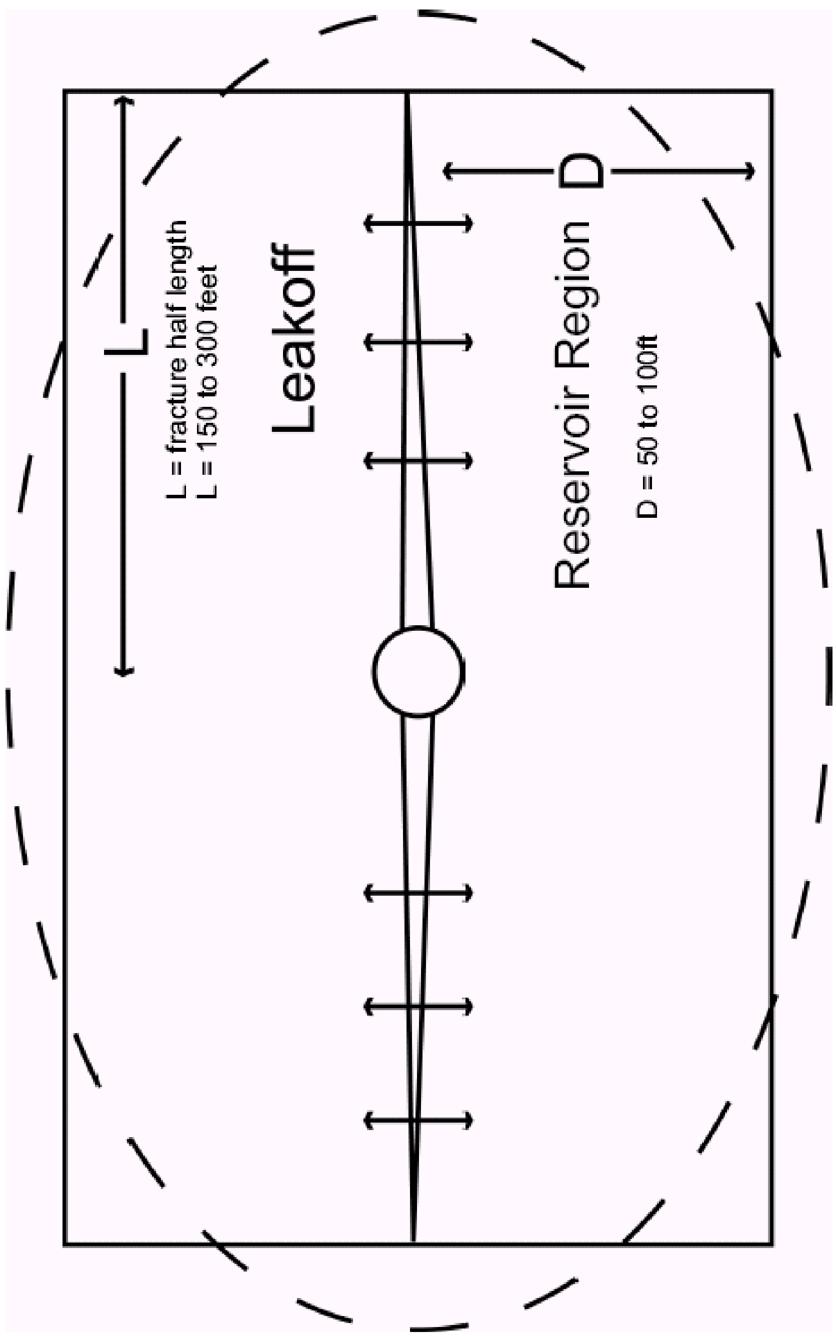
Figure A1-18



Fruitland Net Coal Map.
Note: Cross Sections D20 and S10 are Shown in Figures A1-4 and A1-5
(Ayers and Ambrose, 1990)

7/14/01 kk 1027-SJ-19.cdr

Figure A1-19



Plan View of a Vertical, Two-Winged Coalbed Methane Fracture Showing the Reservoir Region Invaded by Fracturing Fluid Leakoff (Palmer et al., 1991).

Figure A1- 20

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SPE = Society of Petroleum Engineers

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Attachment 10
The Sand Wash Basin

The Sand Wash Basin is in northwestern Colorado and southwestern Wyoming. It is part of the Greater Green River Basin, which includes the Washakie Basin, the Great Divide (Red Desert) Basin, and the Green River Basin (Figure A10-1). These sub-basins are separated by uplifts caused by deformation of the basement rock. The Cherokee Arch, an anticlinal ridge that runs east to west along the Colorado/Wyoming border, separates the Sand Wash Basin from the adjacent Washakie Basin. The Greater Green River Basin, in total, covers an area of approximately 21,000 square miles. The Sand Wash Basin covers approximately 5,600 square miles, primarily in Moffat and Routt Counties of Colorado.

Coalbed methane resources in the Sand Wash Basin have been estimated at 101 trillion cubic feet (Tcf). Approximately 90 percent of this resource is within the Williams Fork Formation (Kaiser et al., 1993). Despite this ample resource, economic viability of recovery of the gas is limited by the presence of large volumes of water in most coalbeds. Presently, there appears to be no commercial production (GTI, 2002); however, approximately 120 permits for drilling within Moffat County were issued between February 2000 and August 2001 (Colorado Oil and Gas Commission, 2001). It is not clear exactly how many of these permits were related to coalbed methane exploration and production.

10.1 Basin Geology

The geologic history of the Sand Wash Basin is relatively complex, characterized by periods of deposition followed by deformation related to tectonic activity. This activity has impacted depositional patterns, coal occurrence and maturity, and hydrology (Tyler and Tremain, 1994). A very thorough discussion of the geologic history of the Sand Wash Basin is available in Tyler and Tremain (1994).

The coal-bearing formations in the region include the Iles, Williams Fork, Fort Union, and the Wasatch Formations (Figure A10-2). These formations were deposited, from bottom to top, during the Upper Cretaceous, Paleocene and upper Paleocene periods. The total thickness of the coal seams in these formations can measure up to 150 feet (Quarterly Review, 1993). Basement rock formations in the Sand Wash Basin can be as deep as 17,000 feet (Tyler and Tremain, 1994). A map of the coal and geologic features is presented in Figure A10-3a and a conceptual cross-section is presented in Figure A10-3b.

The Sand Wash Basin was near the western edge of the Western Interior Seaway that spreads across what is now central North America during the Upper Cretaceous (Figure

A10-4). During the late Cretaceous the seaway retreated to the northeast. Intermontane basins developed during the Laramide, and coal-bearing fluvial-lacustrine sediments were deposited (Quarterly Review, 1993). The coal in the Sand Wash Basin was formed from peat deposited in swamps along a broad coastal plain. Sediments that eroded from nearby uplift formations covered the peat beds (Tyler and Tremain, 1994). The alternating deposition of organic material and sands was repeated many times creating layers of coal interbedded with layers of sandstone and other sedimentary rocks that filled the basin.

Cretaceous or Mesaverde Group coal in the Sand Wash Basin ranges in rank from sub-bituminous along the basin margins to high volatile A bituminous coal in the deeper parts of the basin. These ranks are indicative of moderately mature to well-developed mature coal formed under high pressure and high heat. Within the Mesaverde Group, the most important potential coalbed methane resource in the basin (Kaiser et al., 1993), the coal ranks from sub-bituminous along the basin margins to medium volatile bituminous in the basin center (Kaiser et al., 1993). The methane in these coals formed both biogenically (by bacterial action on organic matter), and thermogenically (under high temperature). The average gas content of 261 coal samples collected during two studies was 147 standard cubic feet of methane per ton of coal (Boreck et al., 1977; Tremain and Toomey, 1983). Some samples from the Sand Wash Basin have been found to contain as much as 540 standard cubic feet of methane feet per ton. Gas content has generally been found to increase somewhat with depth. At depths of less than 1,000 feet, gas content is typically less than 20 standard cubic feet per ton, which has been taken to indicate that gas probably leaked out of the shallow coalbeds into the atmosphere. Analysis of gas samples has indicated that the gas is typically 90 percent methane, the remainder being mostly nitrogen and carbon dioxide (Scott, 1994). Carbon dioxide content ranges from 1 to more than 25 percent (Scott, 1994).

Of all the coal-bearing formations, the Upper Cretaceous Williams Fork is the most significant unit because it contains the thickest and most extensive coalbeds. The Williams Fork Formation is within the Mesaverde Group that also includes the Almond Formation along the Wyoming state line (Tyler and Tremain, 1994). The Almond Formation is shown (Figure A10-2) as a separate formation overlying the Williams Fork (Tyler and Tremain, 1994), but is also reported (Kaiser et al., 1993) to be a lateral equivalent of the upper Williams Fork Formation found in the southern Sand Wash Basin. For more information relative to this apparent conflict see Kaiser et al. (1993, p. 29). The coal-bearing Williams Fork Formation outcrops along the southern and eastern margins of the basin, and may be deeper than 8,000 feet in the deepest part of the basin (Figure A10-3b). The coals are interbedded with sandstones and shale. The thickest total coal deposits in the Williams Fork Formation, up to 129 feet, are centered near Craig, CO. This total is made up of several separate coalbeds up to 25 feet thick interbedded with sedimentary rock.

Stratigraphically above the Williams Fork Formation, the Paleocene Fort Union Formation, which includes sandstone, siltstone, shale, and coal, is also a potentially productive zone for coalbed methane production. The Fort Union outcrops at the Elkhead Mountains east of the basin and along the southern and western parts of the basin. The bottom of the Fort Union Formation is about 7,000 feet below the surface. Net coal thickness can be up to 80 feet with as many as nine individual beds. Individual beds up to 50 feet thick have been identified.

The Wasatch Formation includes beds of shale and sandstone and minor amounts of coal. It can extend as deep as 2,000 feet below the surface. The Wasatch Formation has not been targeted for coalbed methane development because of the small quantity of coal.

10.2 Basin Hydrology and USDW Identification

Regional groundwater flow in the Sand Wash Basin is from east to west and to the northwest towards the center of the basin. Water enters the aquifers at the exposed outcrops along the southern and eastern margins of the basin and moves northwestward. Vertical movement of groundwater, including potential artesian conditions, is dependent on local geologic conditions. Kaiser and Scott (1994) summarized their extensive investigation of groundwater movement within the Fort Union and Mesaverde Group. The Mesaverde Group is a highly transmissive aquifer. The coalbeds along with associated sandstone beds within the group may be the most permeable part of the aquifer. The Williams Fork Formation contains sandstone beds that are reported to be excellent aquifers (Brownfield, 2002). Lateral flow within the Fort Union Formation is slower, in part, owing to less permeable fluvial sandstones in the unit.

Total dissolved solids (TDS) concentrations of groundwater in the Mesaverde Group were investigated by Kaiser and Scott (1994) (Figure A10-5). They found that chloride concentrations ranged from 290 milligrams per liter (mg/L) in the eastern area of the basin near the outcrops where water enters the aquifers, to more than 26,000 mg/L in the central part of the basin. Calcium showed a similar pattern of distribution with the lowest concentrations near the outcrops, increasing toward the basin center. Calcium concentrations ranged from 10 mg/L to over 2900 mg/L. Based on the chloride and calcium concentrations presented by Kaiser and Scott (1994), the water in the aquifers near the recharge areas at the basin margins meets the water quality criteria for an underground source of drinking water (USDW) of less than 10,000 mg/L, but the water in the deeper central part of the basin does not (Figure A10-5). The mapped outcrop area (Figure A10-3a) of the Mesaverde Group indicates that the coal seam lies within a USDW where it is relatively shallow and close to the eastern and southern margins of the basin.

10.3 Coalbed Methane Production Activity

Coalbed methane resources in the Sand Wash Basin have been estimated at 101 Tcf. Approximately 90 percent of this gas is in the Williams Fork Formation (Kaiser et al., 1993). Approximately 24 Tcf of coalbed methane are located at depths less than 6,000 feet below ground surface (Kaiser et al., 1994). Despite this ample resource, economic viability of recovery of the gas is limited by the presence of large volumes of water in most coalbeds. Exploration in the 1980s and 1990s led to limited commercial use of the resource. Records from the Colorado Oil and Gas Commission indicate that approximately 31 million cubic feet of coalbed methane was produced in Moffat County during 1995 (Colorado Oil and Gas Commission, 2001). From 1996 to 1999 (the last year that data are available), no further gas was produced in this County (Colorado Oil and Gas Commission, 2001). However, Colorado Oil and Gas Commission records indicate that approximately 120 permits for drilling within Moffat County were issued during the period from February 2000 through August 2001 (Colorado Oil and Gas Commission, 2001). It is not clear exactly how many of these permits were related to coalbed methane exploration and production, but a handful of the permits were issued to gas companies, and the permits are listed as targeting known coalbeds within specific methane producing formations (Colorado Oil and Gas Commission, 2001).

At Craig Dome in Moffat County, Cockrell Oil Corporation drilled a 16-well development for exploration in the Williams Fork Formation. According to the Colorado Geological Survey, Craig Dome is located along the Cedar Mountain fault system (Colorado Geological Survey, 2002). The wells were abandoned a short time later because of excessive water. The Colorado Geological Survey indicated that the fault system may act as a conduit for anomalously high water migration from the outcrop. An average total of 40 feet of high-volatile bituminous coal was encountered in beds up to 15 feet thick. Gas content was tested at 10 to 350 cubic feet per ton of coal. Wells were cased through the target coalbed, perforated, and hydraulically fractured using water and sand. The wells yielded large volumes of fresh water with TDS levels measuring less than 1,000 mg/L, but little gas (Colorado Oil and Gas Commission, 2001). Water was removed at an average of 21,756 gallons per day per well during testing. Based on records from the Colorado Oil and Gas Commission, Cockrell Oil Corp does not appear to be involved currently with coalbed methane production in this region (Colorado Oil and Gas Commission, 2001).

The Colorado Geological Survey also indicated that faults in Trout Creek Canyon southeast of Craig are on trend with (and thus are likely to be related to) the Cedar Mountain fault system (Colorado Geological Survey, 2002). In addition, KLT Gas Inc. has a pilot program southwest of Craig Dome on the Breeze lease which is on trend with the Cedar Mountain fault system. If a fracture propagates into and along a fault plane, it may contaminate a USDW (Colorado Geological Survey, 2002.)

Limited commercial success has been experienced in the basin. As of 1993, only one commercial operator, Fuelco, was working in the basin. Fuelco was operating 11 wells along Cherokee Arch at 40 to 80 acre spacing. Well depths were to 2,500 feet. A total of 40 feet of coal was found in the Almond Formation (Mesaverde Group) between 810 to 2,360 feet. All wells were cased through the coal, selectively perforated, and stimulated using water and sand. Gas production averaged a total of 50,000 cubic feet per day from four wells. The highest producing well peaked at 100,000 cubic feet per day (Quarterly Review, 1993). Total production of gas through 1993 from the Dixon Field, the only producing field in this region, was about 84 million cubic feet (Kaiser et al., 1993). Total water production for the four wells was high at 126,000 gallons per day due to the high permeability of the coal (Quarterly Review, 1993). Water pumped from the wells contained 1,800 mg/L of TDS and was discharged to the ground with a National Pollution Discharge Elimination System permit (Quarterly Review, 1993).

The Sand Wash Basin has been used by the University of Texas Bureau of Economic Geology in the development of its Coalbed Methane Producibility Model (Kaiser et al., 1994). The development of the model was based on a comparison of basins that included the Sand Wash Basin and the San Juan Basin of southwestern Colorado and northwestern New Mexico. The San Juan Basin has proven to be a very productive coalbed methane resource. The Sand Wash Basin was used as an example of a basin with low potential for productivity (Figure A10-6) (Kaiser et al., 1994).

Hydraulic fracturing has been used in the Sand Wash Basin to improve the flow of gas into the wells. Hydraulic fracturing fluids have typically consisted of water with sand used as a proppant. However, very little information was available regarding specific types and volumes of fluids and proppants used. No indication of the use of other materials was noted in the sources reviewed (Colorado Oil and Gas Commission, 2001).

10.4 Summary

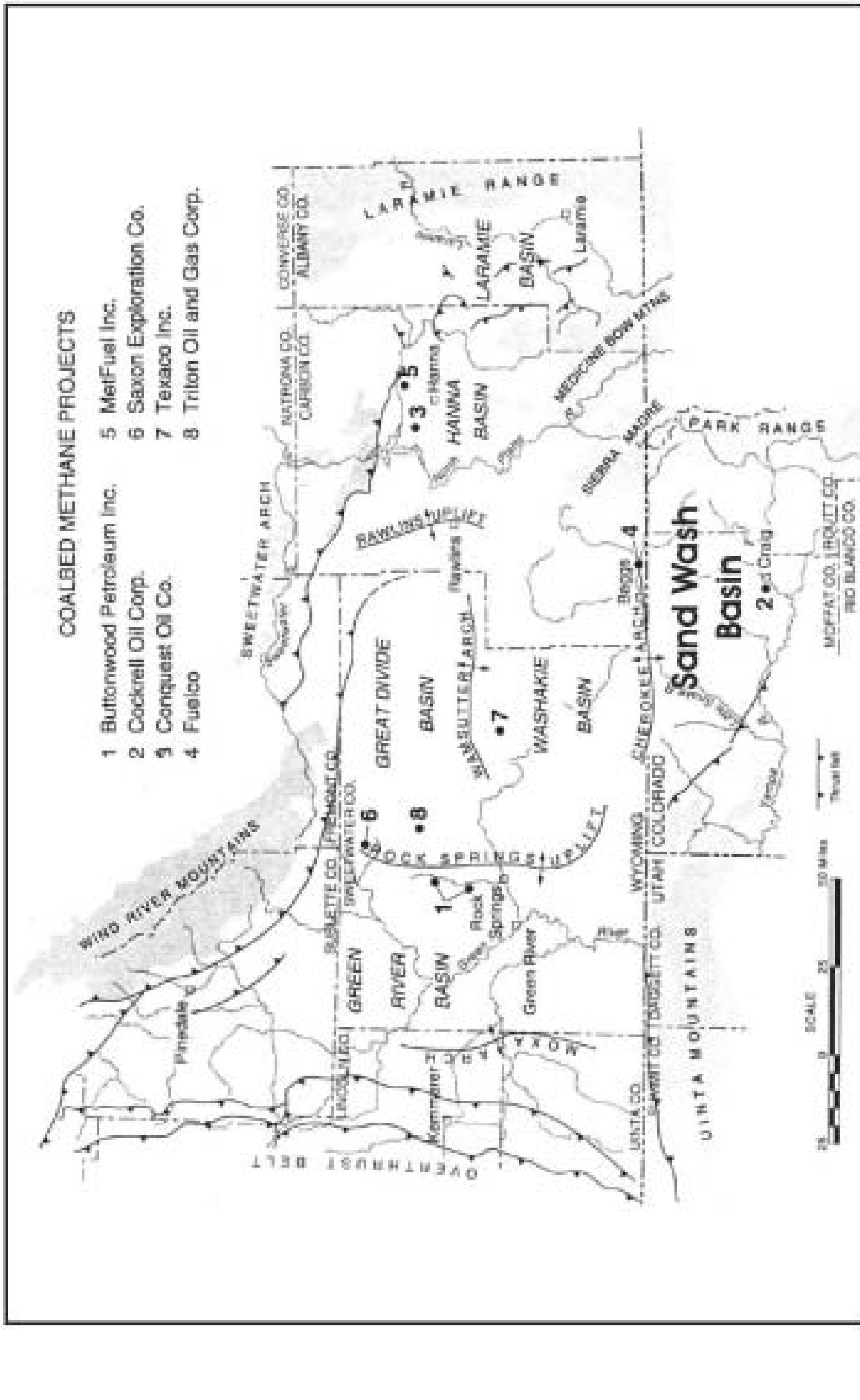
Coalbeds containing methane gas are present within the Sand Wash Basin at accessible depths. Some investigation and very limited commercial development of this resource have occurred, mostly in the late 1980s and early 1990s. There appears to be no commercial production at present. Development of coalbed methane resources in the Sand Wash Basin has been slower than in many other areas due to limited economic viability. The need for extensive dewatering in most wells has been a limiting factor, compounded by relatively low gas recovery.

Between 1996 and 1999, no coalbed methane was produced in Moffat County. Permits for new gas wells have been issued indicating that there may be some continued interest in this area (Colorado GIS, 2001).

Groundwater quality in the basin varies greatly. Typically, chloride and calcium concentrations within the coal-bearing Mesaverde Group are low and potentially within potable ranges in the eastern and southern parts of the basin, implying the existence of a USDW, and therefore the potential for impacts. Concentrations increase as the water migrates toward the central and western margins of the basin. TDS concentrations significantly higher than the 10,000 mg/L USDW water quality standard have been detected in the western portion of the basin.

Compared to other potentially productive areas of the country, very little information has been published regarding current developments, groundwater location and conditions, drilling techniques, etc. The level of information available seems to be commensurate with the amount of commercial activity.

The use of fracturing fluids, specifically water and sand proppant, has been reported for this basin. No record of any other fluid types has been noted. Although variable, the water quality within the fractured coals indicates the presence of USDWs within the coalbeds.



Location of the Sand Wash Basin of Colorado and Wyoming (Quarterly Review, 1993)

Figure A10-1

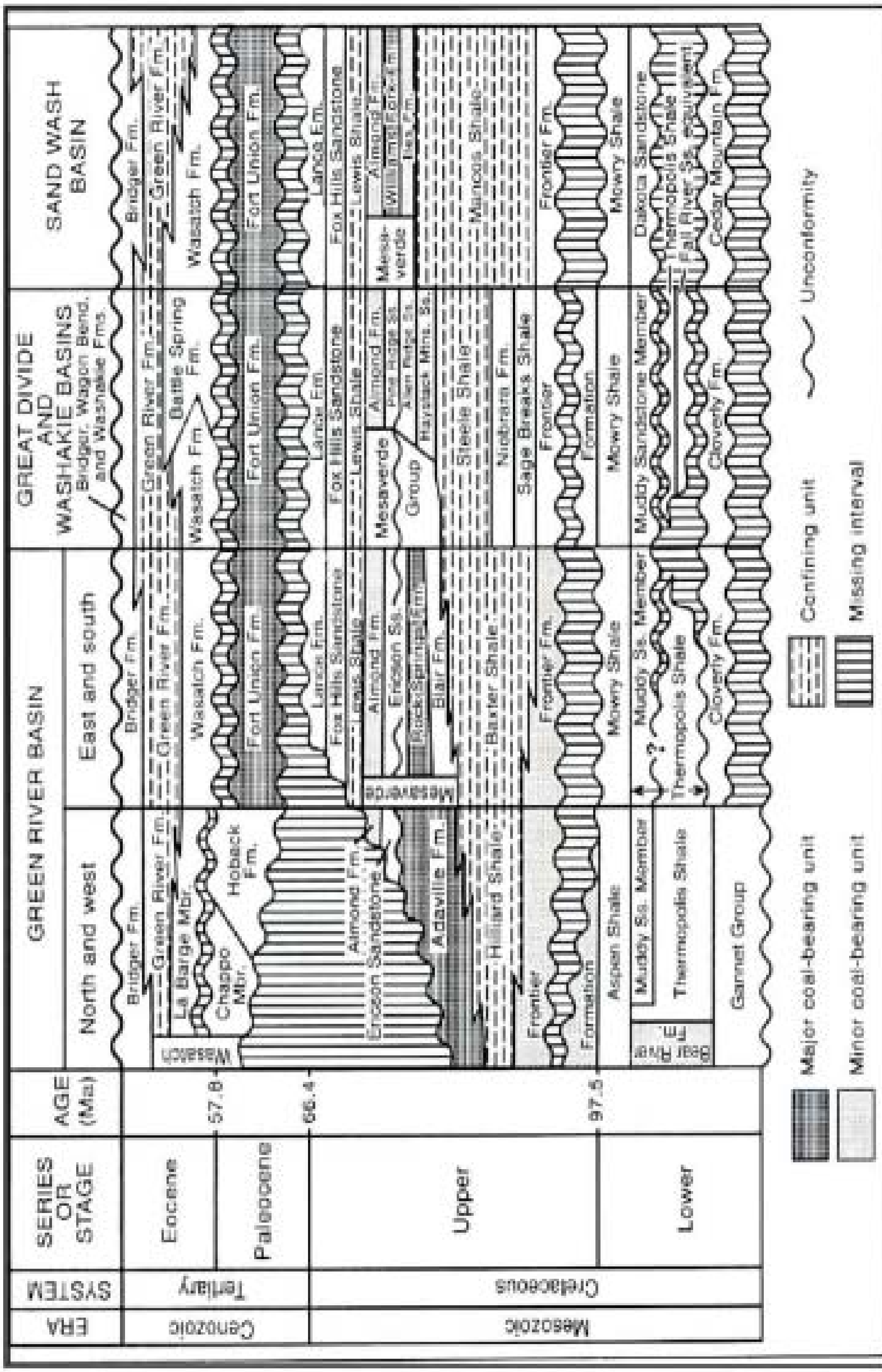
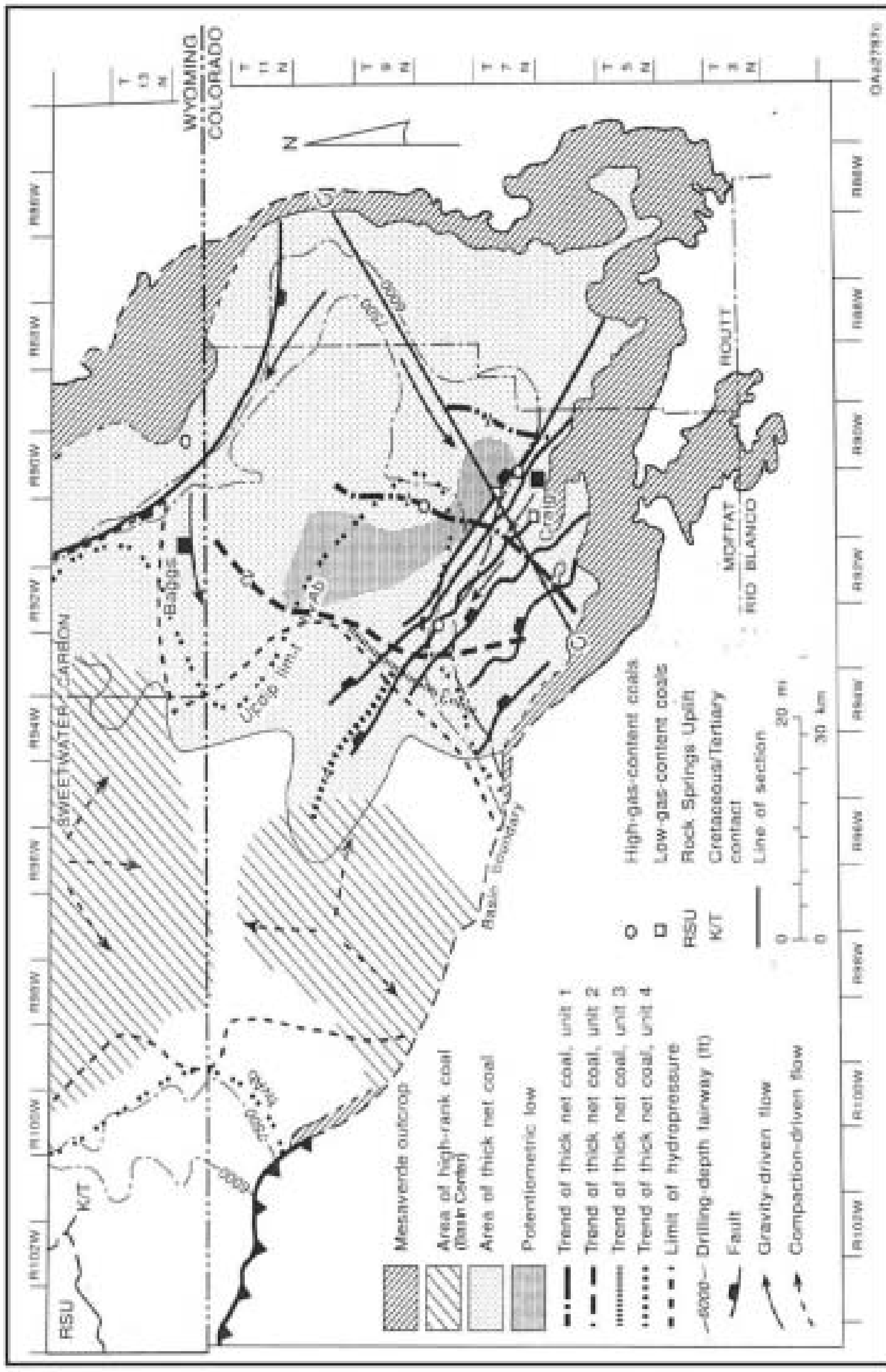


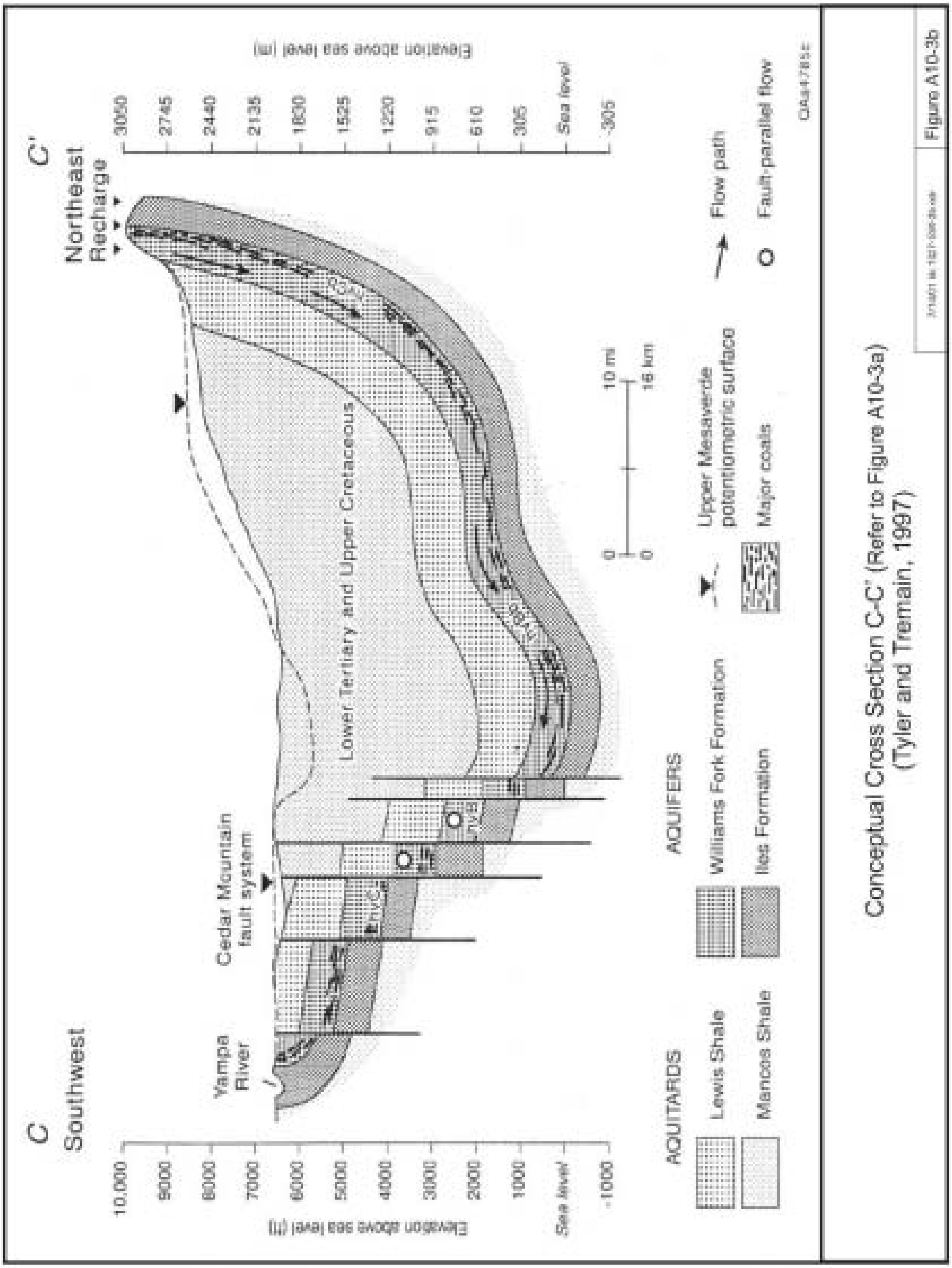
Diagram of Geologic Formations Within the Sand Wash Basin and Neighboring Basins (adapted from Tyler and Tremain, 1994)

Figure A10-2



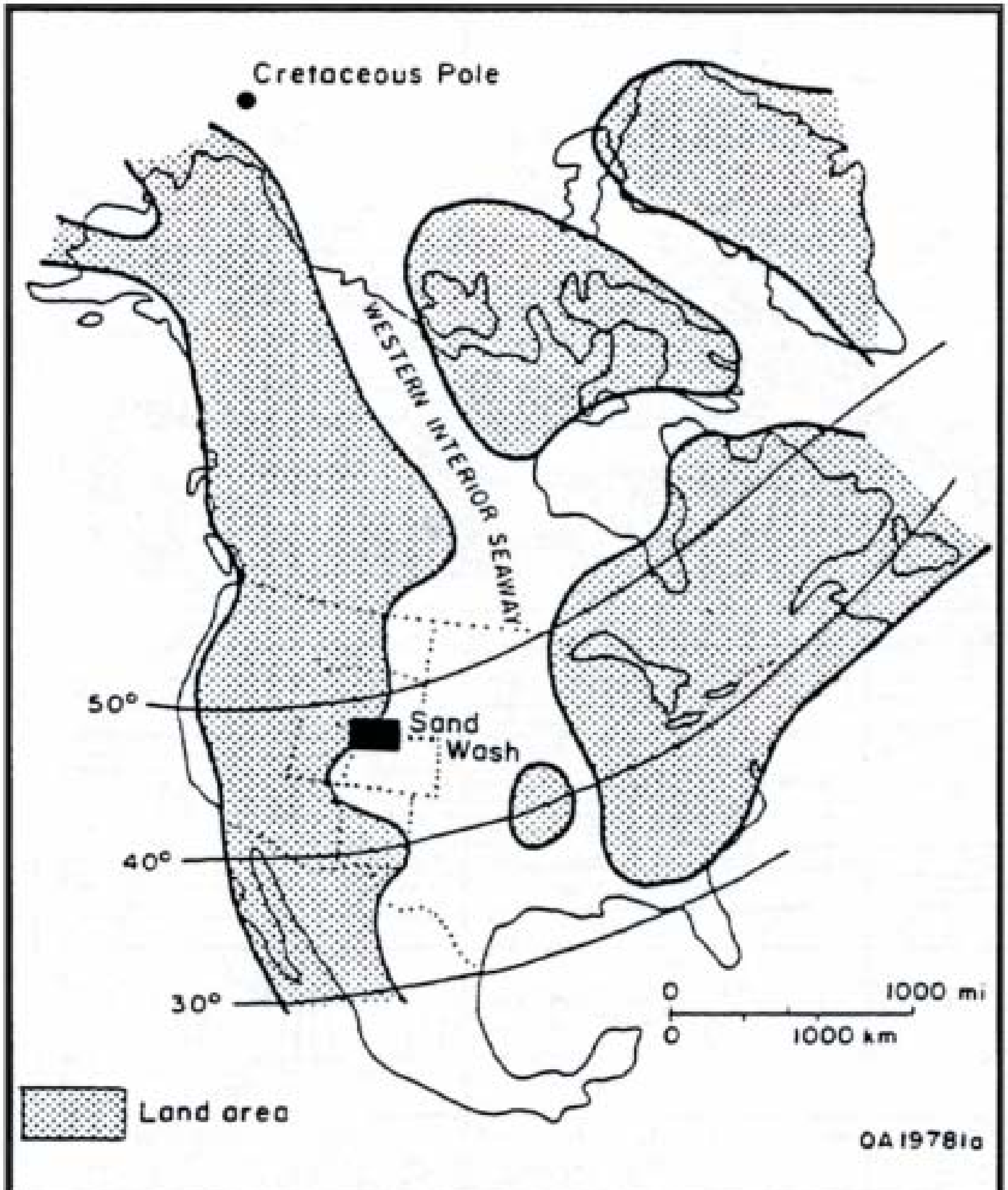
Map of Coal and Geologic Features Within the Sand Wash Basin (Tyler and Tremain, 1997)

Figure A10-3a



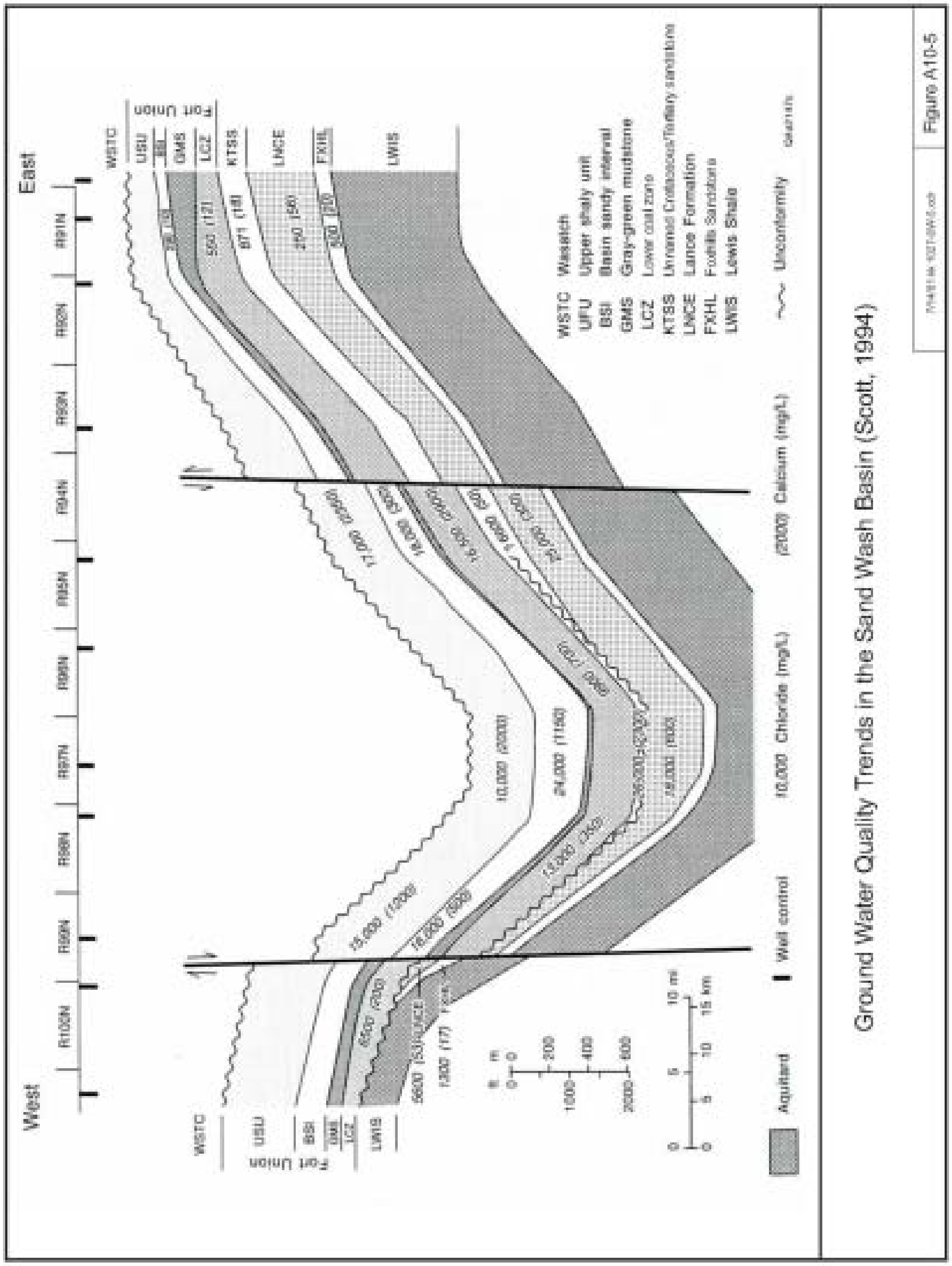
Conceptual Cross Section C-C' (Refer to Figure A10-3a)
(Tyler and Tremain, 1997)

Figure A10-3b



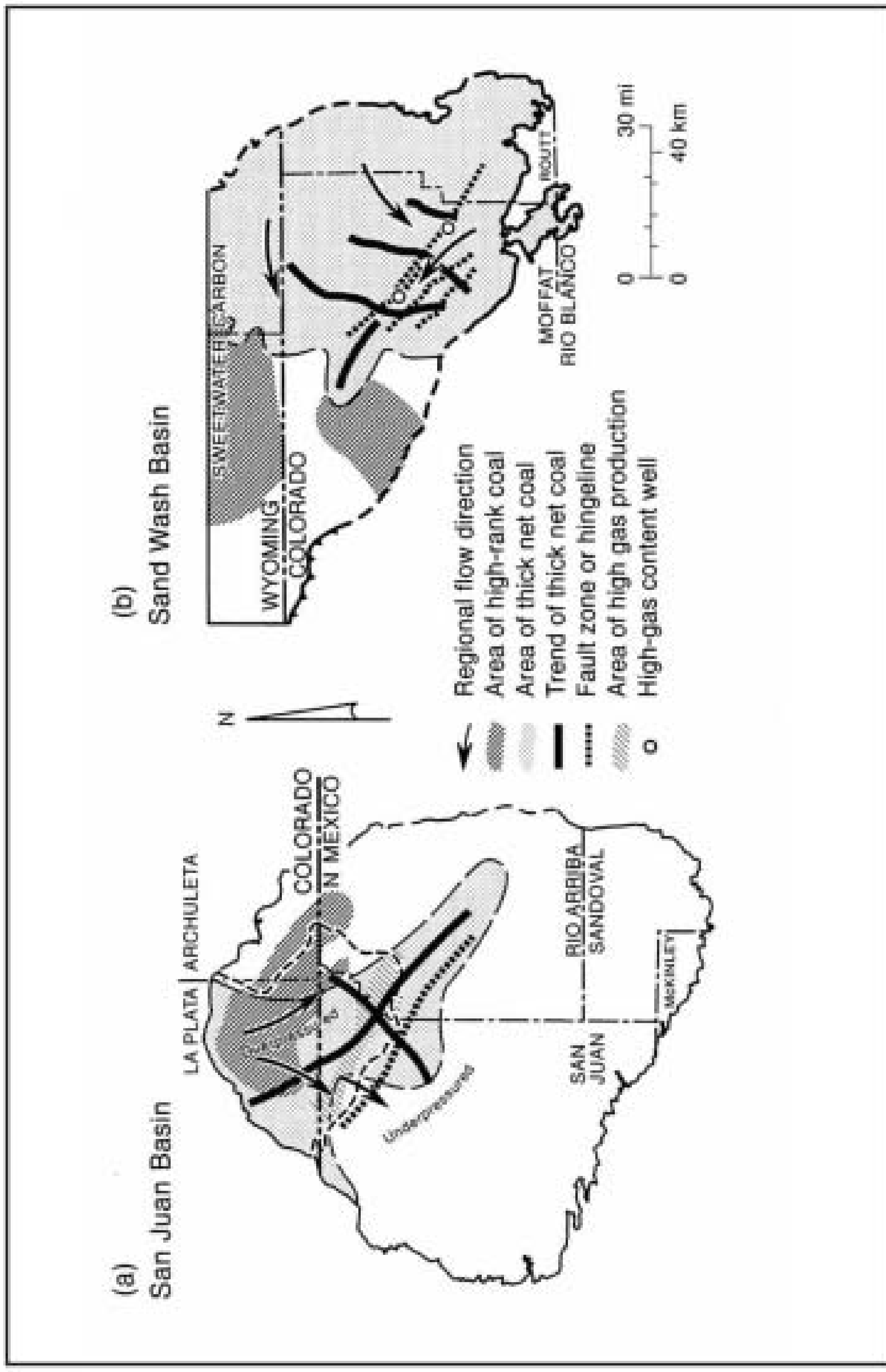
Location of the Sand Wash Basin in Relation to the Western Interior Seaway
of Upper Cretaceous Times (Tyler and Tremain, 1994)

Figure A10-4



Ground Water Quality Trends in the Sand Wash Basin (Scott, 1994)

Figure A10-5



Comparison of Features Relevant to Coalbed Methane Production - San Juan Basin and Sand Wash Basin (Kaiser et al., 1994)

Figure A10-6

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Attachment 11
The Washington Coal Region (Pacific and Central)

The Pacific Coal Region (Figure A11-1) is approximately 6,500 square miles and lies along the western and eastern flanks of the Cascade Range from Canada into northern Oregon. The coals along the western flank lie within the Puget downwarp. Bellingham, Seattle, Tacoma, and Olympia in the State of Washington, and Portland, Oregon lie in or adjacent to the sub-basins. Choate et al. (1980) estimated coalbed methane resources for four target sub-basins (Figure A11- 1) representing 1,800 square miles of the 6,500 square mile Pacific Coal Region to be 0.3 trillion to 24 trillion cubic feet (Tcf). The Central Coal Region (Figure A11-2) is primarily the Columbia Plateau, between the Cascade Range to the west and the Rocky Mountains in Idaho, to the east. The Region extends from the Okanogan Highlands in the north to the Blue Mountains to the south, and encompasses approximately 63,320 square miles. Pappajohn and Mitchell (1991) estimated the coalbed methane potential of the Central Coal Region to be more than 18 billion cubic feet (Bcf) per square mile. According to the available literature, there were no producing fields in either the Pacific Coal Region or the Central Coal Region in Washington as of 2000 (GTI, 2001).

11.1 Basin Geology

A series of discontinuous coal fields lie along the western flank of the Cascade Range (Figure A11-3). The Roslyn and Taneum-Manastash fields are located on the eastern flank of the Cascade Range (Figure A11-3). The coal-bearing sediments were formed in a swampy fluvial-deltaic coastal plain depositional environment in the Paleocene to late Eocene Eras. In the Columbia Plateau Region, the Cretaceous to Eocene coal-bearing rocks are buried beneath a thick sequence of extrusive basalts.

The coal-bearing deposits of the Pacific and the Central Coal Regions are Cretaceous to Eocene Age and formed within fluvial and deltaic depositional environments prior to the uplift of the Cascade Mountain Range. The coalbeds of the Pacific and Central Basins are thought to result from peat accumulations in poorly drained swamps of the lower deltas while the thinner coalbeds probably formed in the better drained upper deltas (Buckovic, 1979 as cited in Choate et al., 1980). During the Oligocene, Cascade volcanic activity buried the deltaic sediments and compression caused some deformation of the sediments. During the Miocene, extensive volumes of basalt poured out in central Washington and covered the coal-bearing fluvial deposits. During the late Pliocene, the Coast Range and the Cascades continued to be uplifted, separating the Pacific Coal Region from the Central Coal Region, and causing extensive tectonic deformation, folding and faulting, of the coal-bearing sediments.

Deformation of the coal-bearing rocks increases toward the Cascade front. Fracturing may enhance porosity and permeability of the coalbeds, allowing greater methane storage and production (Pappajohn and Mitchell, 1991). On the other hand, however, fracturing may also increase the porosity and permeability of confining beds, allowing methane to escape up the stratigraphic section over time and dissipate in the atmosphere. Continuing deformation, primarily faulting, may be a limiting factor controlling methane production in the Pacific Coal Region as well.

11.1.1 Pacific Coal Region Geology

In the Pacific Coal Region, deformation has increased geologic complexity making it difficult to follow or correlate coalbeds, especially across faults. Geothermal heating along the western flank of the Cascades created a thermally altered zone of increased coal rank ranging into the bituminous and anthracite ranks. The maturation to bituminous rank increases potential methane yields (Walsh and Lingley, 1991; Pappajohn and Mitchell, 1991).

The major coal-bearing areas are in, from north to south, Whatcom, Skagit, King, Pierce, Kittitas, Thurston, Lewis, and Cowlitz Counties in Washington (Figure A11-3). The discussion of regional geology presented here illustrates the geologic conditions in the Green River district in King County, the Wilkerson-Carbonado coalfield in Pierce County, and the Centralia-Chehalis district in northern Lewis and southern Thurston Counties, and does not attempt to provide a detailed description of every coalfield. For more detailed information on the Bellingham area, Whatcom County, the reader is referred to Beikman et al. (1961), for Whatcom and Skagit Counties to Jenkins (1923 and 1924), and for the Roslyn coal area to Walker (1980). Other areas not discussed but important within the Pacific Region are the Toledo-Castle Rock District, and the Roslyn-Cle Elum and Teneum-Manastash fields. The stratigraphy for three sub-basins (Green River, Wilkerson-Carbonado, and Centralia-Chehalis) of the Pacific Coal Region is presented in Figure A11-4. The general setting and geology of each sub-basin is unique and complex.

The coal deposits of King County are located southeast of Seattle (Figure A11-3). The Green River district is the largest and most extensively mined coal-bearing area in King County. The King County coals occur in the Puget Group of Eocene Age (Figure A11-4). Evans (1912) divided the Puget Group into 3 coal zones, which, from oldest to youngest, are the Bayne, Franklin, and Kummer. Deformation has been moderate and most of the coalbeds dip less than 35 degrees. In parts of the Green River district the deformation has been more intense, and dips of 50 degrees or more are common. The King County coals range in rank from subbituminous to high-volatile bituminous. Within the Green River District, the Puget Group is estimated to be at least 6,500 feet thick and contains at least 15 coalbeds up to 40 feet thick (Beikman et al., 1961). The principal coalbeds are located in the Franklin and Kummer zones in the Puget Group (Vine, 1969). Coal has been mined in the Green River District since about 1883, and it has produced more than 25 million tons of coal. Currently there is no coal production in the district.

The Wilkerson-Carbonado coalfield is located in Pierce County, southeast of Seattle (Figure A11- 3). The Pierce County coals occur in the Eocene Carbonado Formation (Beikman et al., 1961). The Carbonado consists of more than 5,000 feet of interbedded, layered lenses of sandstone, siltstone, mudstone, and shale with carbonaceous shale and coal (Figure A11-4). At least 10 coalbeds have been identified in the area. Coalbeds range in thickness from 1 to 5 feet with the maximum thickness of 15 feet. The coals range in rank from high-volatile bituminous to low-volatile bituminous. The Wilkerson-Carbonado coals have the highest rank of any major coal-bearing area in Washington State. Throughout the field, deformation has been intense. Dips of 60 degrees or more are common, and fault displacements range from a few feet to more than 1,500 feet. Although these areas have recently been targets of coalbed methane exploration, there is currently no production.

The coal deposits of Lewis and Thurston Counties occur in the Skookumchuck Formation (Figure A11-3) of late Eocene Age (Snavely et al., 1958). The Centralia-Chehalis district is located in northern Lewis and southern Thurston Counties (Figure A11-3). Deformation of the Skookumchuck is moderate resulting in tightly folded anticlines and broad open synclines. The coal deposits have been cut by a series of high angle reverse faults roughly paralleling the fold axes. The faults dip to the northeast, with the southwest block downthrown, and have displacements ranging from 200 to 500 feet. The coal rank ranges from lignite to anthracite. The central part of the Centralia-Chehalis district contains as many as 14 subbituminous coalbeds ranging from a few inches to over 40 feet in thickness. The district contains more than half of the calculated coal reserves of the State. The TransAlta Centralia Mining Company continues to operate a major strip mine centered about 5 miles northeast of Centralia, where it is anticipated that 9,400 acres will be stripped over 35 years. Within the Centralia mine, the Big Dirty bed is more than 40 feet thick. To the west of Centralia, the Vader coal area contains several lignite beds with thickness up to 20 feet, which may correlate in part with the coals in the Centralia-Chehalis area.

In Whatcom and Skagit counties (Figure A11-3), the Chuckanut Formation contains as many as 15 coalbeds, ranging from 1 to 15 feet thick and ranking from lignite to anthracite, but generally bituminous. The rank of the coal increases eastward towards the crest of the Cascades Range.

The rank of Pacific Region coals varies greatly from place to place, ranging from lignite to anthracite, but generally rank increases toward the crest of the Cascade Range. The coal rank is used to identify bituminous coal-target areas where gas yields may be greatest. While the structural geology is very complex, the thermally-altered metamorphic zone is rather predictable. Both of these factors will play a major role in the design of any exploration and development plans for coalbed methane in the Pacific Coal Region.

The complex stratigraphy and structural deformation of the lenticular coals in the Pacific Coal Region are major obstacles to the exploration and development of coalbed methane fields. Predicting the location of coalbeds is a complex and difficult process because the geology in the area has been modified by intense deformation. Additionally, the faulting that commonly occurs along the axes of anticlines may form conduits for the escape of methane through overlying confining beds. Steeply dipping beds of coal have presented difficulties in controlling drill bit directions and in development and stimulation for coalbed methane production.

Choate et al. (1980) estimated coalbed methane resources for four target sub-basins (Figure A11-1), representing 1,800 square miles of the 6,500 square mile Pacific Coal Region, to be 0.3 trillion to 24 Tcf. Methane had been encountered in 67 oil and gas exploration wells drilled in this region by 1984. Methane gas was found at depths of less than 500 feet in 25 wells, less than 1,000 feet in 38 wells, and less than 2,000 feet in 50 wells. In western Whatcom County, methane has been found in unconsolidated glacial drift capped by impervious clay beds. East of Ferndale, methane gas reportedly has been produced commercially from unconsolidated deposits at depths ranging from 166 to 193 feet at flow rates ranging from 750,000 to 5,000,000 cubic feet per day (Choate et al., 1980).

11.1.2 Central Coal Region Geology

The Central Coal Region refers to the coal-bearing formations east of the Cascade Range. The Columbia River Basalt Group, primarily the Grande Ronde Basalt, Wanapum Basalt, and Saddle Mountains Basalt bury the Cretaceous to Eocene coal-bearing formations of the Central Coal Region. In this region, methane is entrained in groundwater from confined aquifers in the basalts. Interbedded with the flood basalts are epiclastic and volcaniclastic sediments. The less fractured zones of basalt appear to act as aquitards (Johnson et al., 1993). Johnson et al. (1993) have concluded that the greatest volume of methane is derived from upward migration from the underlying Eocene coals. They also suggest that faults through the underlying sediments and basalts provide conduits for the migration of gas-bearing groundwater into the confined zones.

The Yakima fold belt lies between the confluence of the Snake and Columbia Rivers and the Cascade Range, and is a series of broad asymmetric anticlines and synclines whose axes generally trend west northwest to east southeast (Figure A11-5). The anticlinal ridges are typically cut by thrust faults that are inclined and steepen with depth (Reidel et al., 1989). While the anticlines may form structural traps for methane in the source coalbeds, the thrust faults in the anticlines may form conduits for the upward migration of methane through overlying confining beds. The fold structures are very flat and broad and do not result in the steeply dipping strata that are characteristic of the Pacific Coal Region west of the Cascades.

11.2 Basin Hydrology and USDW Identification

Surficial deposits of Pleistocene glacial outwash locally form aquifers capable of sustaining public drinking water supplies in the Pacific and Central Washington Regions. In the Central Coal Region, aquifers in the basalts are extensively developed for irrigation. Public water supplies in Pierce County (Olympia area) and King County (Seattle area) of the Puget Sound Region (Pacific Coal Basin) are obtained from the glacial drift aquifer (Dion, 1984) that overlies Eocene sediments, which may contain coal and methane. Water quality information from four gas test wells indicates the presence of 1,330 to 1,660 milligrams per liter (mg/L) total dissolved solids (TDS) in water within the coalbeds of Pierce County (Dion, 1984). This meets the water quality requirements of an underground source of drinking water (USDW). The Washington Department of Ecology and the EPA deemed this water to be of sufficient quality to permit its discharge to surface waters of the Carbon River (Pappajohn and Mitchell, 1991).

The Columbia River Basalt Group is identified as a major regional multi-aquifer province (Lindholm and Vaccaro, 1988; Dion, 1984). The aquifer is used extensively for irrigation, but may also be used as a source of drinking water. Wells in the Basalts commonly yield 150 to 3,000 gallons per minute. TDSs in the water produced generally range from 250 to 500 mg/L (Dion, 1984).

The occurrence of methane in groundwater is one factor leading to the assessment of the coalbed methane production potential in Washington. Methane in groundwater occurs in the basalts, but only in confined aquifers (porous or fractured zones near the top or bottom of a basalt layer), and is thought to have migrated upward from underlying coalbeds. Water supply wells and irrigation wells in the Columbia River Basalts and water wells in numerous different lithologies in the Pacific Coal Region have been recognized as containing methane. Data demonstrating the co-location of a coal seam and a USDW were found for Pierce County, where methane gas test well results report TDS levels far lower than the 10,000 mg/L USDW water quality threshold (Dion, 1984).

11.3 Coalbed Methane Production Activity

Complex stratigraphy and structural deformation creates major obstacles to the development of gas from the Pacific Coal Region. The coals are known from active and inactive mines to be gassy, folded, faulted, and commonly steeply inclined. The difficulties and dangers involved with underground coal mining led to closure of the mines once the shallow deposits were exhausted. However, their characteristics have been well documented by the mining operations. Many of these same structural characteristics have impeded the development of coalbed methane gas. The available literature indicates that no significant production had been achieved by 1996 (GRI, 1999). According to the available literature, there were no producing fields in either the Pacific Coal Region or the Central Coal Region in Washington as of 2000 (GTI, 2001). However, in northwest Oregon, the Mist gas field was developed in the 1990s.

11.3.1 Pacific Coal Region Production Activity

Between 1986 and 1993, 19 coalbed methane wells were drilled in the northern Pacific Coal Region (Quarterly Review, 1993). Three tests were conducted near the town of Black Diamond in the Green River coal area of King County. One of the wells was hydraulically fractured and the others completed by open-hole cavitation. Steep dips of the strata led to wellbore deviation during drilling and to caving following the fracturing operations. One well produced 32,000 to 62,000 cubic feet per day of coalbed methane gas with no water in an open-hole test. Another was hydraulically fractured with 12/20 mesh sand and nitrogen foam in two zones at depths of 2,228 to 2,442 feet and 2,505 to 2,638 feet, but no test results were released. Caving was so prominent that it interfered with wellbore cleanup following the hydraulic fracturing operations. According to available publications, optimal fracturing and completion methods for use in the structurally difficult Pacific Coal Region are yet to be applied and proven.

11.3.2 Central Coal Region Production Activity

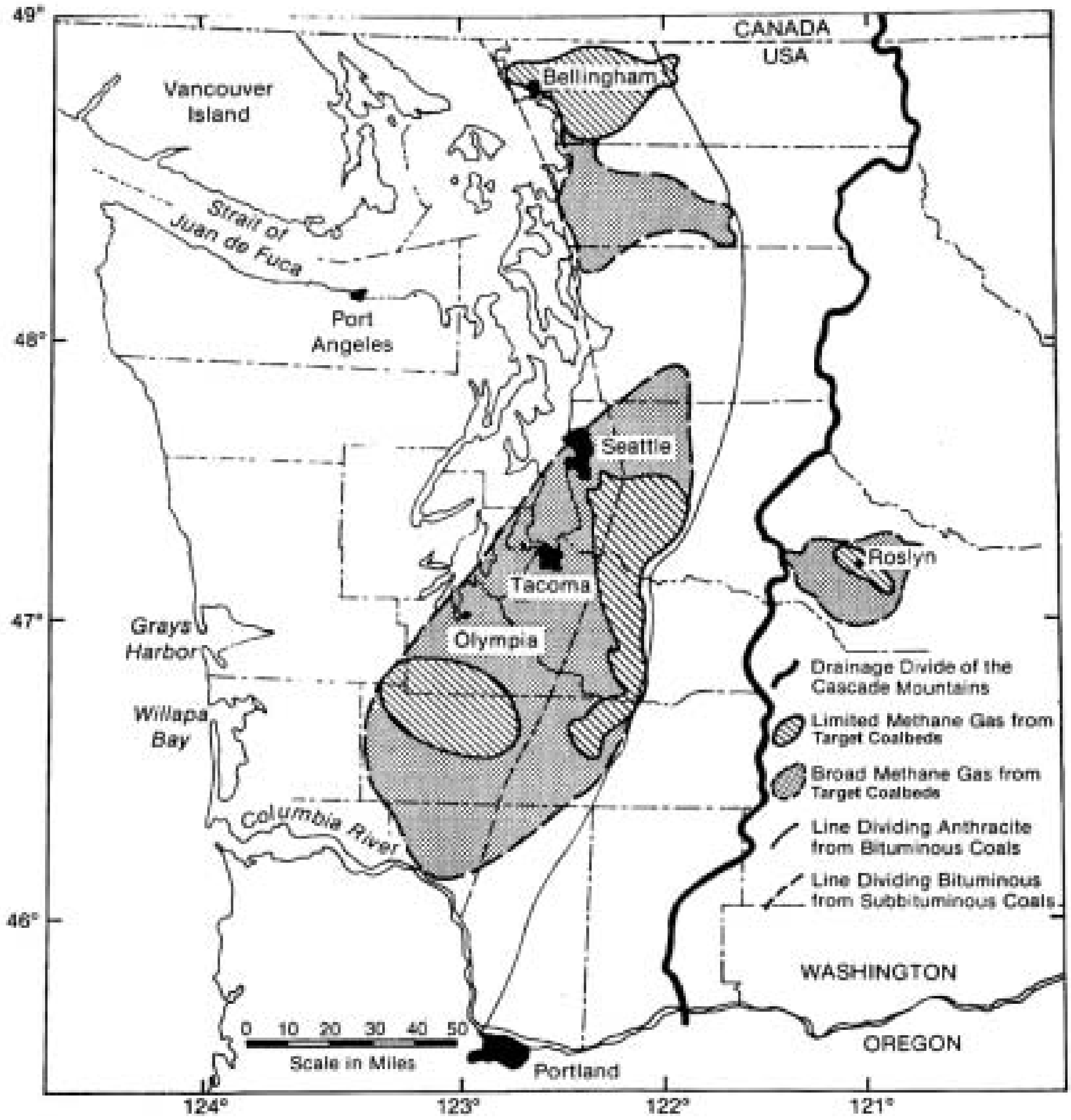
The one commercial gas field (Rattlesnake Hills) in the Central Coal Region was shut down in 1941. Production from the Cretaceous to Eocene coalbeds that lie below the basalts may have large potential. Pappajohn and Mitchell (1991) estimated the coalbed methane potential of the Central Coal Region to be more than 18 Bcf per square mile. It is unlikely that the whole 63,320 square miles of the region could yield that rate because the coals are only known to occur below the basalts in the western part of the basin. Much is not known about the potential coalbed methane production from these obscured deposits, and development depends on successful exploration.

Although the coals of the Central Coal Region may not be as greatly deformed and unpredictable as those in the Pacific Coal Region, they are overlain by the Columbia River Basalt Group, in which individual basalt flows up to 300 feet thick can cover thousands of square miles. The Rattlesnake Hills gas field operated between 1913 and 1941 in the western part of this region and indicates greater potential for development.

11.4 Summary

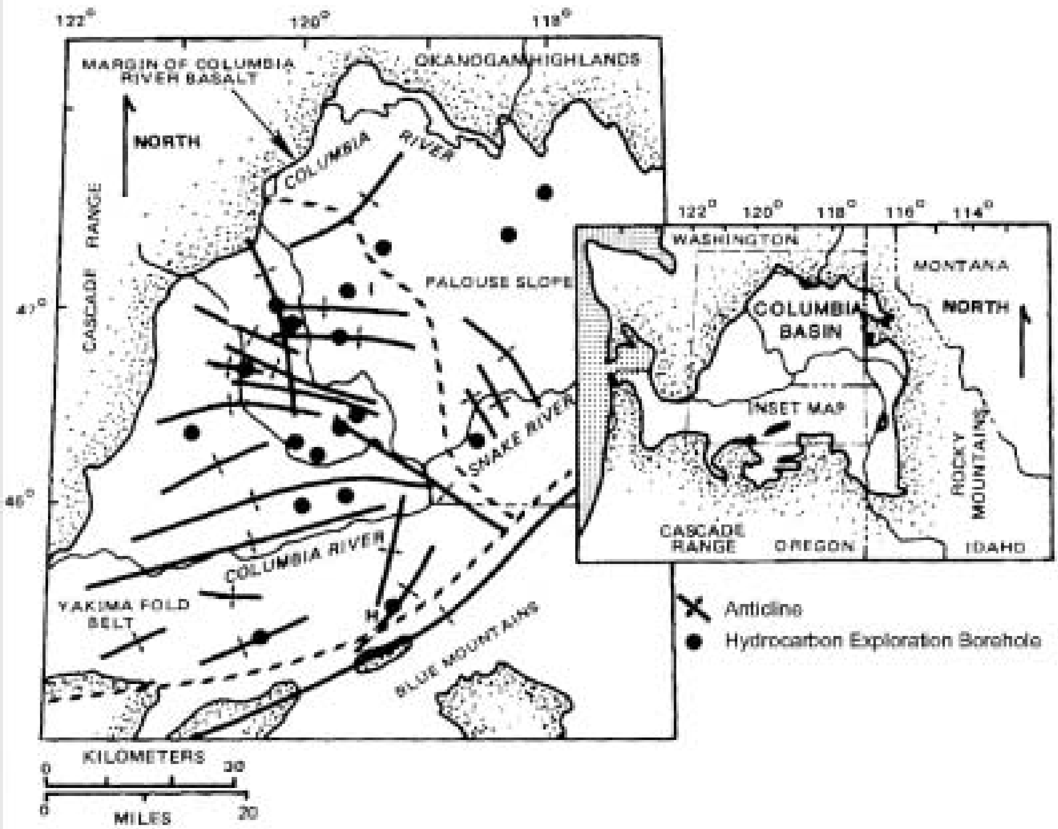
The geologic structure of the coal-bearing rocks is difficult to interpret in the Pacific and Central Coal Regions, and methane may be technically difficult to produce in these regions. A connection exists between the Washington coalbeds and a USDW. However, there were no producing coalbed methane wells in the Pacific and Central Coal Regions in Washington as of 2000 (GTI, 2001). In some areas, the Pacific and Central Regions' coals exist within a potential USDW. In other areas of the basin, there is evidence that the coalbeds are below a USDW. Hydraulic fracturing has been documented in this region. Data demonstrating the co-location of a coal seam and a USDW were found for Pierce County, where methane gas test well results report TDS levels of 1,330 to 1,660 mg/L, far less than the USDW classification limit of 10,000 mg/L (Dion, 1984).

In this region, methane occurs in groundwater flowing through fractured zones in basalts, although less fractured zone of the basalts appear to act as hydraulic confining layers. Johnson, et al. (1993) concluded that the greatest volume of this methane has migrated upward from underlying coalbeds. Water supply wells and irrigation wells in the Columbia River Basalts and water wells in numerous different lithologies in the Pacific Coal Region have been recognized as containing methane. Development of coalbed methane in the Washington Coal Region may have some impact on highly productive basalt aquifers that meet the requirements of a USDW and are already in use as large sources of irrigation water for agriculture.



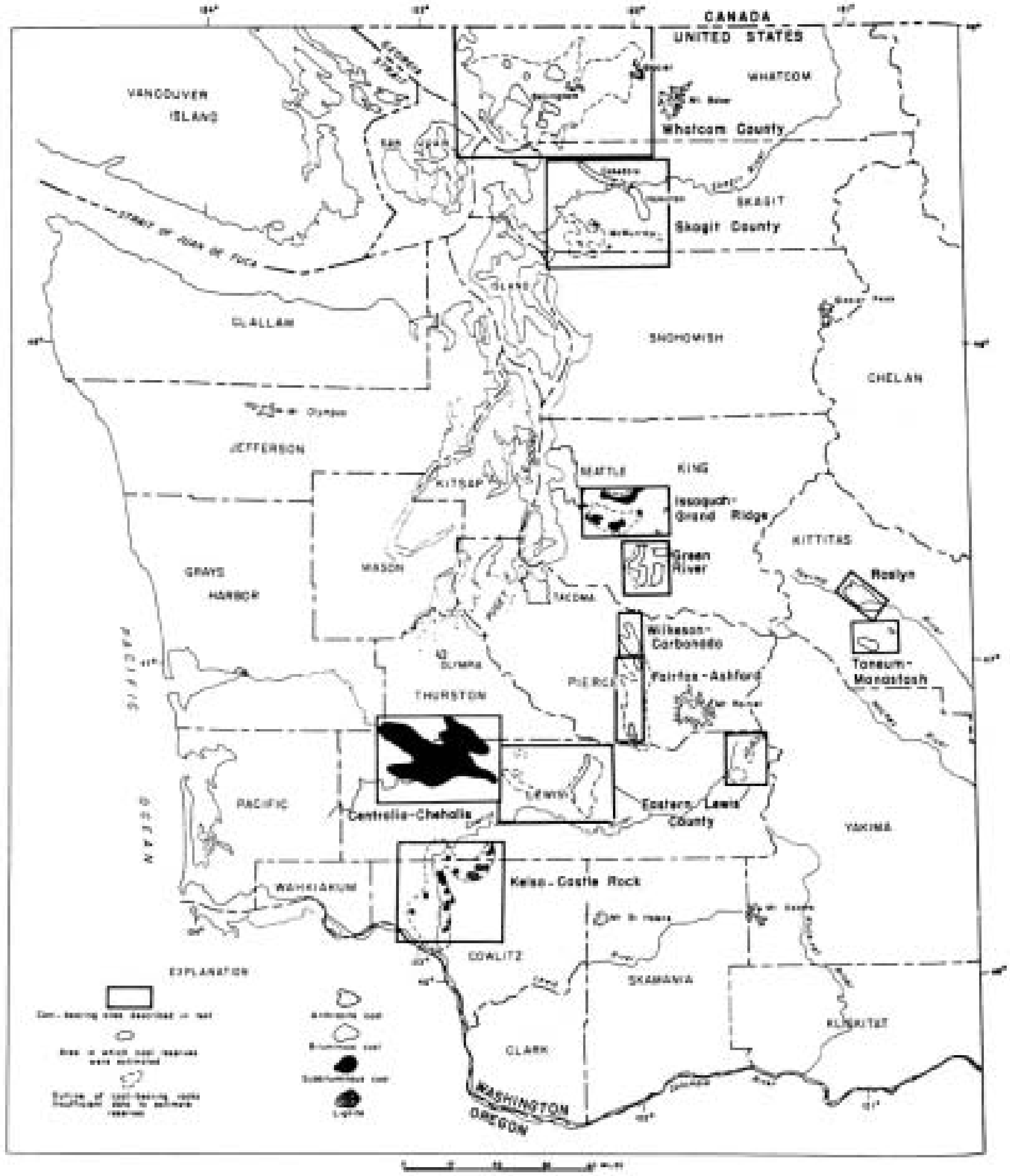
The Pacific Coal Region Showing Targeted Subbasins
Used for Coalbed Methane Estimates (Choate et al., 1980)

Figure A11-1



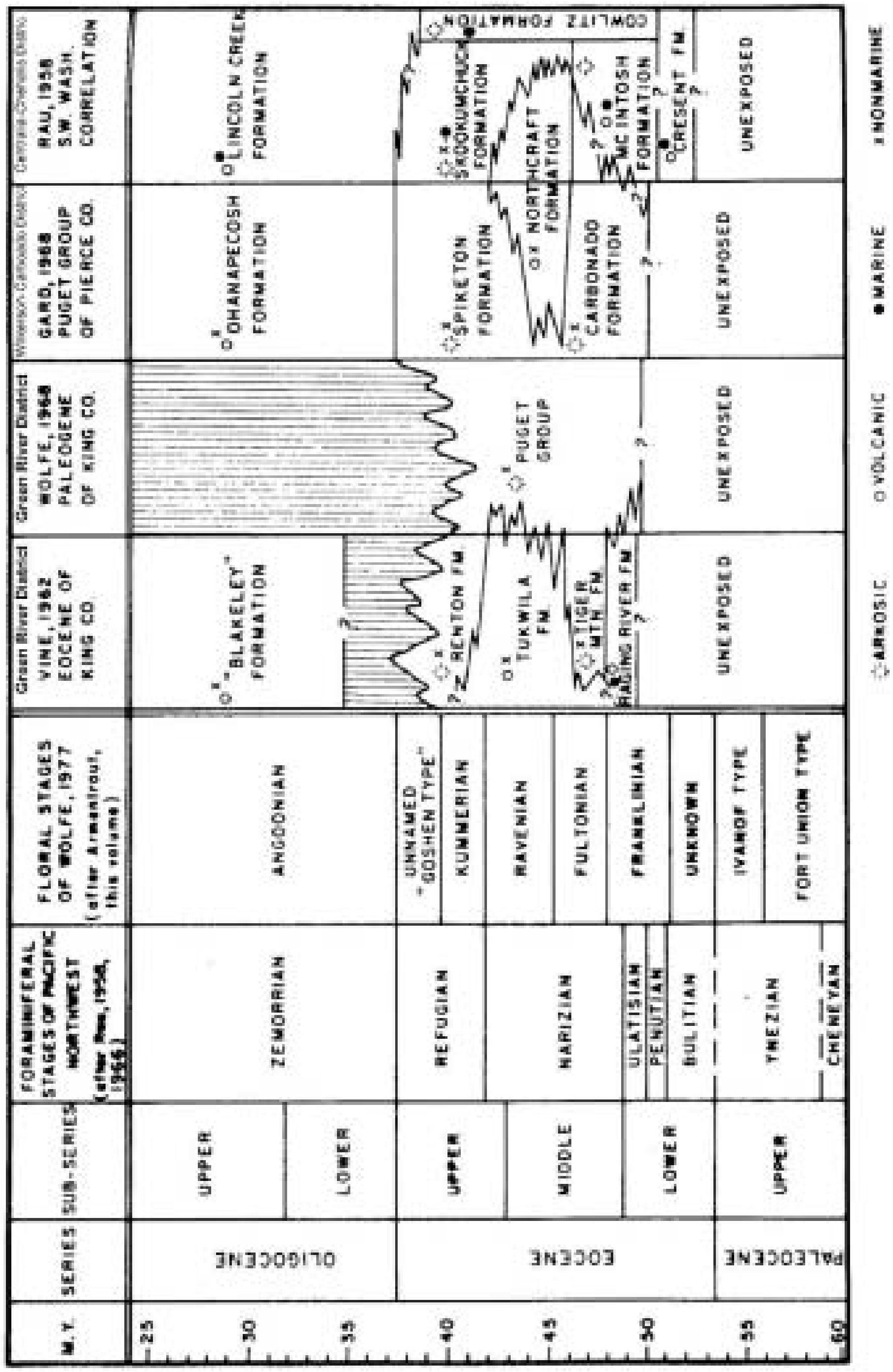
The Central Coal Region (Johnson et al., 1993)

Figure A11-2



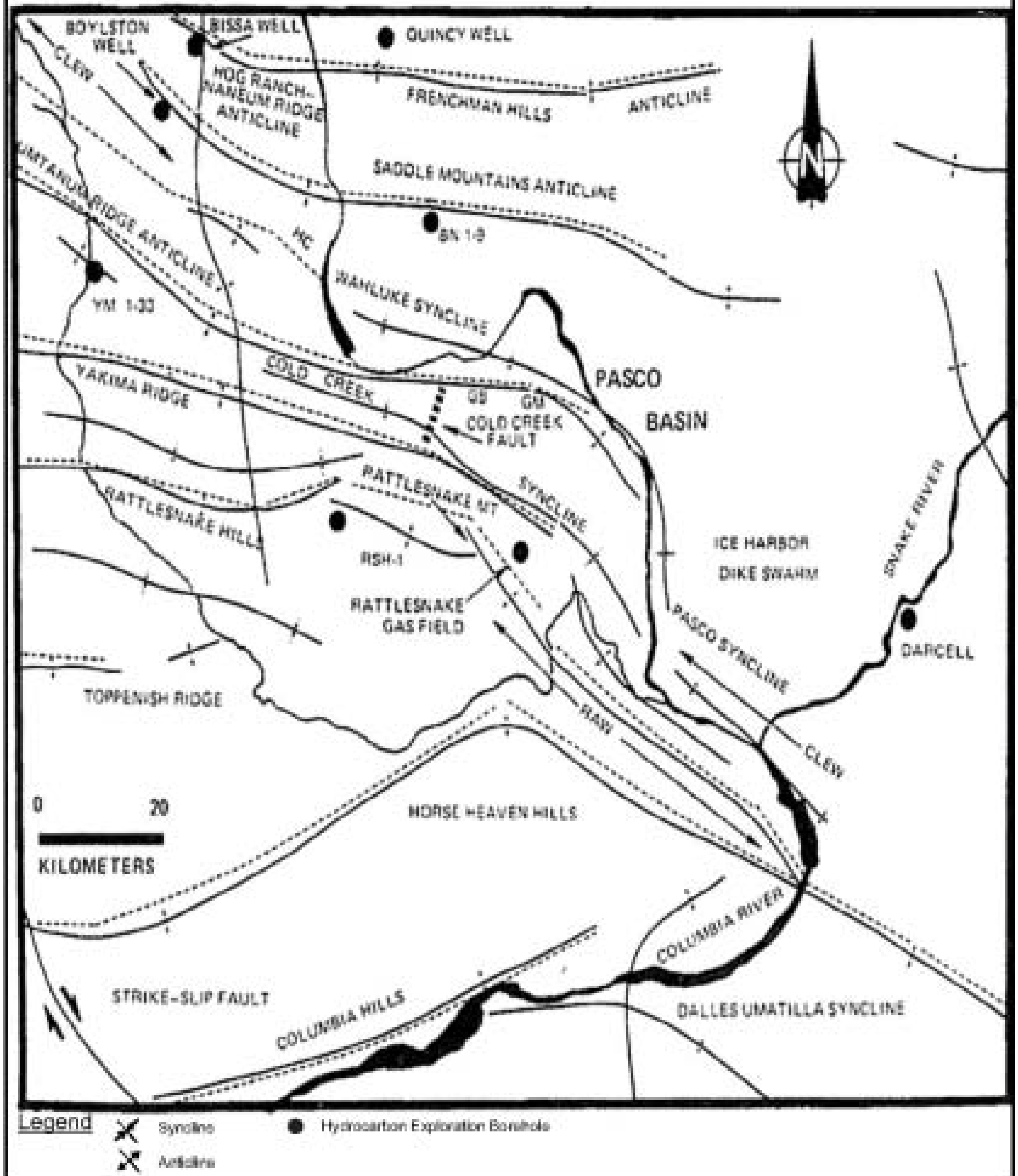
Major Coal-Bearing Areas in Western Washington (Choate et al., 1980)

Figure A11-3



Stratigraphy for Three Coal Districts of the Pacific Coal Region (Choate et al., 1980)

Figure A11-4



Structural Map of the Central Columbia Basin and Yakima Fold Belt
(Johnson et al., 1993)

Figure A11-5

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Attachment 2
The Black Warrior Basin

The Black Warrior Basin covers an area of about 23,000 square miles in Alabama and Mississippi. The basin is approximately 230 miles long from west to east and approximately 188 miles long from north to south. Coalbed methane production in Alabama is limited to the bituminous coalfields of west-central Alabama, primarily in Jefferson and Tuscaloosa Counties.

Coalbed methane production in the Black Warrior Basin is among the highest in the United States. In 1996, approximately 5,000 coalbed methane wells were permitted in Alabama. In 2000, this number increased to over 5,800 wells (Alabama Oil and Gas Board, 2002). Coalbed methane well production rates range from less than 20 to more than one million cubic feet per day per well (Alabama Oil and Gas Board, 2002). Between 1980 and 2000, coalbed methane wells in Alabama produced roughly 1.2 trillion cubic feet of gas. According to the Gas Technology Institute (GTI), annual gas production was 112 billion cubic feet in 2000 (GTI, 2002).

2.1 Basin Geology

Coalbed methane production in the Black Warrior Basin (Figure A2-1) is contained within the Upper Pottsville Formation of Pennsylvanian age (300 million years). The depositional history along the ancient coastline of prehistoric Alabama was characterized by 8 to 10 “coal deposition cycles” of sea level rising and lowering. Each of these 10 geologic “coal deposition cycles” features mudstone at the base of the cycle (deeper water) and coalbeds at the top of the cycle (emergence) (Pashin and Hinkle, 1997).

The geologic structure of the Black Warrior Basin is complex. Due to erosion and structural uplift, not all of the coal zones are present at all locations (Pashin et al., 1991; Young et al., 1993). In general, however, most coalbed methane wells tap the Black Creek/Mary Lee/Pratt cycles, at depths that range from 350 to 2,500 feet deep (Holditch, 1990).

Alabama coalbeds are typically very thin, ranging from less than 1 inch in thickness to 4 feet (in rare cases they may be up to 8 feet thick in surface mines) (Horsey, 1981; Heckel, 1986; Eble et al., 1991; Carrol et al., 1993; Pashin, 1994) (Figure A2-2). In the area of coalbed methane development, the Pottsville Formation exists at or near the surface, and the depth to commercial coalbeds ranges from the surface outcrop to 3,500 feet, depending on location (Figure A2-3).

2.2 Basin Hydrology and USDW Identification

In the location where coalbed methane development is taking place in west-central Alabama, the Pottsville Formation is an unconfined aquifer. The matrix permeability of Pottsville rocks (e.g., mudstone, cemented sandstone) is low, but water is present and flows within an extensive system of faults, fractures, and joints. Flow patterns within the Pottsville Formation are strongly controlled by fault- and fold-related isotropic joints and fractures (Koenig, 1989). The close spacing and systematic pattern of cleats, however, make coalbeds the most productive aquifers within the Pottsville Formation (Koenig, 1989; Pashin et al., 1991; Pashin and Hinkle, 1997). In the early 1990s, several authors reported fresh water production from coalbed wells at rates up to 30 gallons per minute (Ellard et al., 1992; Pashin et al., 1991).

Most of the recharge to the Pottsville aquifer is precipitation that infiltrates from the surface, but some recharge occurs where streamflow enters the outcrop and moves laterally into the aquifer along folded anticlinal beds (Pashin and Hinkle, 1997) (Figure A2-4). Several researchers also propose upwelling of more saline waters from deeper zones, which takes place along vertical, fault-related, rubble zones (Pashin et al., 1991). Discharge from the Pottsville aquifer is primarily from the dewatering of coalbeds due to mining and coalbed methane production (Pashin et al., 1991).

Formation water produced from Alabama coalbed methane wells contains between less than 50 to over 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) (Koenig, 1989; Pashin et al., 1991; Pashin and Hinkle, 1997). Some portions of the Pottsville Formation contain waters which meet the quality criterion of less than 10,000 mg/L TDS for an underground source of drinking water (USDW) (Figure A2-7). According to the Alabama Oil and Gas Board, some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels which are considerably higher than 10,000 mg/L (Alabama Oil and Gas Board, 2002). Water quality generally decreases with increasing depth (Figures A2-7 and A2-8), and areally is related to the faulting pattern (Figure A2-9) (Pashin et al., 1991; Pashin and Hinkle, 1997). Waters exceeding 10,000 mg/L TDS can be found below 3,000 feet in areas near deep vertical faults, suggesting upwelling from deeper, more saline zones (Pashin and Hinkle, 1997).

2.3 Coalbed Methane Production Activities

Alabama coalbed methane wells are categorized into three distinct types. The first two types, “gob” wells and horizontal wells, are less common. Gob wells are associated with mines. The well is drilled to a depth above the mine roof, and when the mine is abandoned, the roof collapses. Gob wells produce coalbed methane from the fractured mine debris. A few horizontal wells are drilled from within mines to reduce coalbed methane concentration in advance of a working face. The third type, which includes 98 percent of all Alabama methane wells, includes vertically drilled wells that utilize mainstream oilfield technologies (Pashin and Hinkle, 1997). Because neither gob nor horizontal wells typically are hydraulically fractured, this discussion is limited to vertical wells.

According to literature, most coalbed methane wells are drilled using water or air rotary methods or water-based mud, due to lower cost and concerns that mud fluids will invade the coal. Wells in Alabama are completed with tubing. Water is pumped up the tubing for disposal, whereas gas is produced up the annulus. Wells are drilled to a depth 10 to 30 feet below the lowest coalbed to create a sump that collects coal fines and allows water to separate from the coalbed methane (Holditch, 1990).

About 95 percent of produced water is disposed by discharge into surface water, via Type II National Pollution Discharge Elimination System permits (O’Neil et al., 1989; O’Neil et al., 1993; Pashin and Hinkle, 1997). These permits require some water quality monitoring and limit instream water quality to 230 mg/L TDS (Pashin and Hinkle, 1997). Since 1991, about 5 percent of produced water has been injected for disposal into Class II injection wells (Pashin and Hinkle, 1997). Eight Class II wells are currently active (Alabama Oil and Gas Board, 2001), disposing coalbed waters into zones between 4,300 and 10,000 feet deep (Ortiz et al., 1993).

Most wells are completed in multiple coal zones using perforations. Some wells are completed in mudstones immediately below a coal zone, rather than within the coal (“limited entry” completions), and a few wells feature un-cased, open-hole completions. Each well is hydraulically fractured to allow communication with the thin coal seams outside of the casing, and most wells are fractured more than once as described below:

- In wells with multiple coal seams present, the hydraulic fracturing process may involve several or multiple stimulations, using 2 to 5 hydraulic fracture treatments per well (depending on the number of seams and spacing between seams); and,

- Many coalbed methane wells are re-fractured at some time after the initial treatment, in an effort to re-connect the wellbore to the production zones to overcome plugging or other well problems (remedial fracture-stimulation) (Holditch, 1990; Saulsberry et al., 1990; Palmer et al., 1991a and 1991b; Schraufnagel et al., 1991; Holditch, 1993; Palmer et al., 1993b; Spafford et al., 1993; Schraufnagel et al., 1993) (Figure A2-10).

The geometry of hydraulic fractures in coalbed methane zones usually differs from that observed in conventional oil and gas scenarios. In conventional hydrocarbon zones, the gas and/or oil are physically “trapped” by the presence of an impermeable confining layer, usually shale. Shale formations may present a barrier to upward fracture growth because of the stress contrast between the coalbed and the higher-stress shale (see Appendix A). Therefore, for conventional fracturing, the vertical growth of fractures out of the target zone may be limited by the presence (i.e., stress contrast) of overlying shales. In conventional gas-well fracture environments, fracture half-length (200-1,600 feet from the well bore) almost always exceeds fracture height (10-200 feet above the perforations). In the Black Warrior Basin, however, the lithologic properties and stress fields of the coal cycles typically produce fractures that are higher than they are long ("length" refers to horizontal distance from the well bore) (Morales et al., 1990; Zuber et al., 1990; Holditch et al., 1989; Palmer and Sparks, 1990; Jones and Schraufnagel, 1991; Steidl, 1991; Wright, 1992; Palmer et al., 1991b and 1993a).

In the Black Warrior Basin of Alabama, hydraulic fractures created in coalbed methane deposits are able to grow much higher than some fractures in "conventional" gas reservoirs. There are three primary reasons for this phenomenon:

- Due to coal's low modulus of elasticity (i.e., brittleness, stiffness) and complex fracture geometries, high pressures are required to fracture coal hydraulically (500 to 2,000 pounds per square inch (psi), or 0.7 to 2.0 psi/ft), and high treatment pressure often causes preferential extension of the fracture in the vertical dimension (Jones et al., 1987; Reeves et al., 1987; Morales et al., 1990; Palmer et al., 1991a);

- The economics of coalbed methane production in this basin requires tall fractures that penetrate several coal seams. The coal seams are typically thin (1 to 12 inches) and economically viable production requires the drainage of as many seams as possible. Because coal seams may be vertically separated by up to hundreds of feet of intervening rocks, operators usually design fracture treatments to enhance the vertical dimension and might perform several fracture treatments within a single well (Ely, et al., 1990; Holditch, 1990; Saulsberry et al., 1990; Spafford, 1991; Holditch, 1993); and,

- The other rocks within the Pottsville coal cycles (jointed mudstone and sandstone) fracture much more easily than coal (Teufel and Clark, 1981; Saulsberry et al., 1990; Jones and Scraufnagel, 1991; Spafford, 1991). Because there are no significant barriers to fracture height (Simonson et al., 1978; Ely et al., 1990; Palmer et al., 1991a), vertical fractures in the Black Warrior basin typically penetrate several thin coalbeds and hundreds of feet of intervening rocks (Teufel and Clark, 1981; Hanson et al., 1987; Holditch et al., 1989; Ely et al., 1990; Palmer et al., 1991c; Schraufnagel et al., 1991; Spafford, 1991; Palmer et al., 1993b) (Figure A2-11).

Mined-through studies in the Black Warrior Basin identified many instances where thin (less than 1-foot thick) shales overlying targeted coalbeds were fractured. Penetration into layers above the coal was observed in more than 80 percent of the fractures intercepted by mines underground in the Black Warrior Basin (Diamond, 1987b). Some fractures continued completely through very thin shales (Diamond, 1987a and b). These studies did not conduct a systematic assessment of the extent of the vertical fractures through and above the roof rock shales.

Several researchers conclude (based on pressure behavior during fracturing and several examples where mines penetrated hydraulic fractures) that shallow fractures have a horizontal component as described below:

- Fractures that are created at shallow depth typically have more of a horizontal component and less of a vertical component. The vertical component is most likely due to the presence of vertical natural fractures (cleats and joints) as pre-existing planes of weakness from which vertical fractures can initiate.

- Fractures created at a greater depth can propagate vertically to shallower depth, and develop a horizontal component. In these “T-fractures”, the fracture tip may fill with coal fines and/or intercept a zone of stress contrast, which causes the fracture to “turn” and to develop horizontally.

As noted above, penetration of the layers above the coal was observed in more than 80 percent of the fractures intercepted by mines underground in the Black Warrior Basin (Diamond, 1987b), but, as coals become shallower, the potential for fracture height growth decreases. In general, horizontal fractures are most likely to exist at shallow depths (less than 1,000 feet). As depths increase, it is more likely that a simple vertical fracture will occur (Gas Research Institute, 1995).

Sand is the most common proppant used in coalbed methane treatments in Alabama. The amount of sand injected per fracture treatment ranges from 10,000 to 120,000 pounds (Holditch et al., 1989; Palmer et al., 1991b and 1993a). Fracture widths in the formation vary from 0.5 inches to closed (i.e., no proppant emplaced), depending on distance from wellbore and efficiency of the proppant displacement into the length of the fracture (Palmer and Sparks, 1990; Palmer et al., 1993a; Steidl, 1993).

Fracturing fluid (30,000 to 200,000 gallons per treatment) is injected at a rate of 5 to 50 barrels per minute (which equals 210 to 2,100 gallons per minute) at injection pressures ranging from 500 to 2,300 psi (Palmer et al., 1989 and 1993b; Holditch et al., 1989; Pashin and Hinkle, 1997). The most common constituent of fracturing fluid is plain water. Several researchers conclude that approximately 75 percent of all coalbed methane wells in Alabama were fractured using cross-linked gel fluids (Palmer et al., 1993a; Pashin and Hinkle, 1997).

According to service companies, diesel fuel is no longer used as a component of fracturing fluids in Alabama. In addition, additives that could introduce chemicals exceeding maximum contaminant levels (MCLs) are no longer used in fracturing fluids in Alabama.

Table A2-1 presents some data concerning the general chemical makeup of common fracturing fluids used in Alabama from literature published prior to the Alabama hydraulic fracturing regulation (Economides and Nolte, 1989; Penny et al., 1991). In addition, most gel fluids utilize a breaker compound (usually a borate or persulfate compound or an enzyme, at 2 lb/1,000 gal) to allow post-treatment thinning and easier recovery of gels from the fracture. Several researchers conclude that approximately 75 percent of all coalbed methane wells in Alabama were fractured using cross-linked gel fluids (Palmer et al., 1993a; Pashin and Hinkle, 1997).

According to Hunt and Steele (1992), environmental regulations restrict local disposal of used fracturing fluids, and fracturing fluids are transported to regulated disposal sites. Robb and Spafford (1991) reported that acids were used to fracture production zones as shallow as 400 feet deep.

In fracture treatments of wells in homogeneous formations in conventional gas fields, injection is temporary and the majority of fracturing fluid is subsequently pumped back up through the well when production resumes.

There are limited data in the literature concerning the volume of fracturing fluids subsequently pumped back to the well after stimulation has ceased. Palmer et al. (1991b) found that only 61 percent of fracturing fluids were recovered during production sampling of a coalbed well in the Black Warrior Basin of Alabama, and projected that 20 to 30 percent would remain in the formation.

2.4 Summary

Coalbed methane development and hydraulic fracturing in the Black Warrior Basin of Alabama takes place within a USDW, the Pottsville formation. Some portions of the Pottsville Formation contain waters which meet the quality criteria of less than 10,000 mg/L TDS for a USDW. Some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels that are considerably higher than 10,000 mg/L (Alabama Oil and Gas Board, 2002).

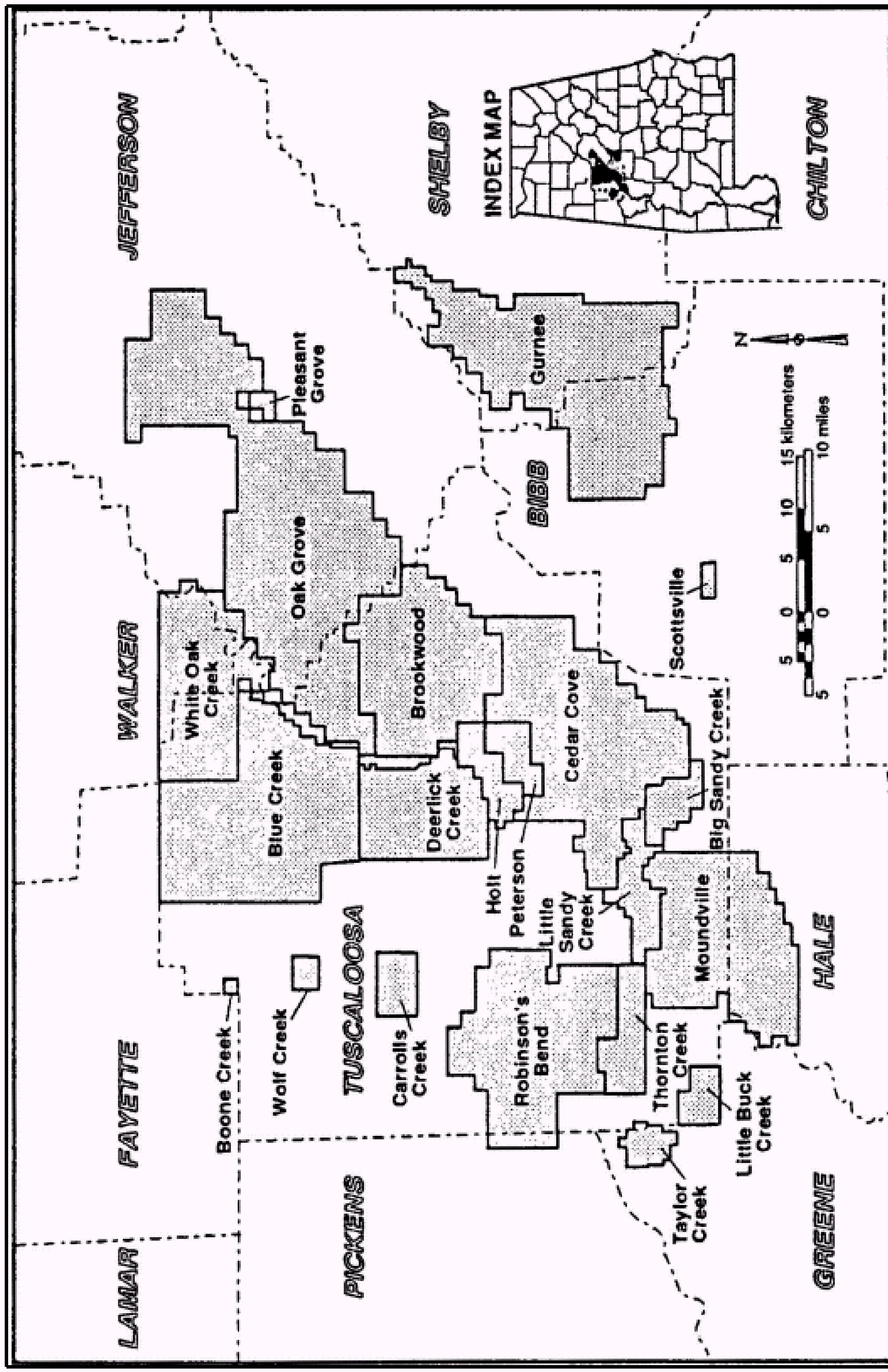
According to service companies, diesel fuel is no longer used as a component of fracturing fluids in Alabama. In addition, additives that could introduce chemicals exceeding MCLs are no longer used in fracturing fluids in Alabama.

In the Pottsville Formation, the lack of a significant vertical barrier can provide for extensive fracture height growth (Holditch et al., 1989; Lambert et al., 1989; Ely et al., 1990; Saulsberry et al., 1990; Palmer and Sparks, 1990; Spafford, 1991; Palmer et al., 1991a and 1993a; Spafford et al., 1993; Gas Research Institute, 1995). Mined-through studies in the Black Warrior Basin identified many instances where thin (less than 1-foot thick) shales overlying targeted coalbeds were fractured. Penetration into layers above the coal, which are typically shale, was observed in more than 80 percent of the fractures intercepted by mines underground in the Black Warrior Basin (Diamond, 1987b).

Table A2-1. Chemical Components Previously Used in Typical Fracturing/Stimulation Fluids for Alabama Coalbed Methane Wells

Type of Stimulation Fluid	Composition	pH
Fluids		
Hydrochloric acid	15% HCl water solution	<1-3
"Slick" water	water-soluble solvent as viscosity reducer (% unknown)	NA
Diesel oil	NA	NA
Gels[1]		
R-F	3% resorcinol, 3% formaldehyde, 0.5% KCl, 0.4% $NaHCO_3$	6.5
Pfizer Flocon 4800	0.4% xanthan, 154 ppm Cr^{3+} (as $CrCl_3$), 0.5% KCl	4.0
Marathon MARCIT	1.4% polyacrylamide (HPAM), 636 ppm Cr^{3+} (as acetate), 1% NaCl	6.0
DuPont LuDox SM	10% colloidal silica, 0.7% NaCl	8.2
CPAM crosslinked with Pfizer Floperm 500	0.4% cationic polyacrylamide (CPAM), 1520 ppm glyoxal, 2% KCl	7.3
Drilling Specialties HE-100 Crosslinked	0.3% HPAM-AMPS, 100 ppm Cr^{3+} (as acetate), 2% KCl	5.0

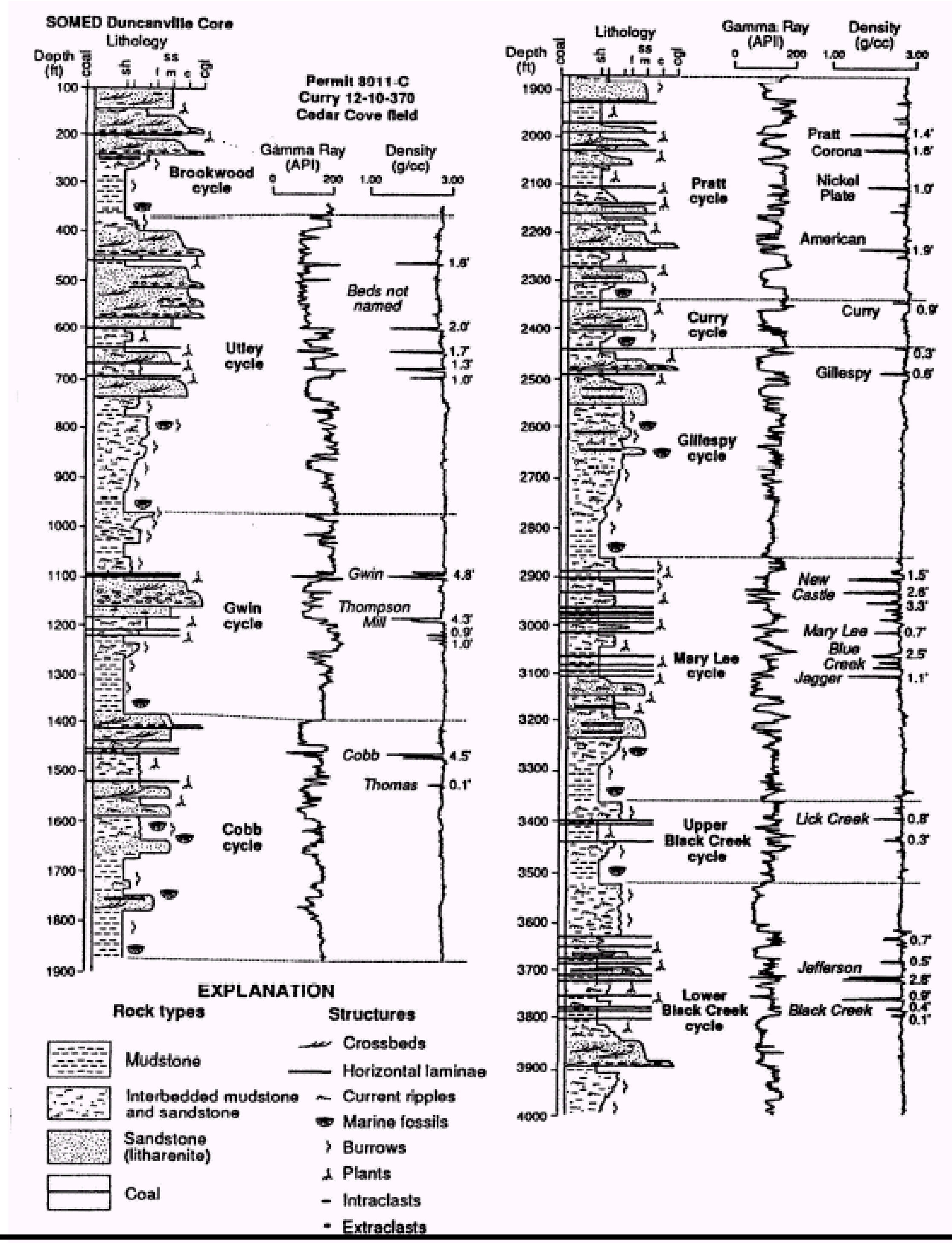
[1] Gels are typically mixed at a ratio of 40 lbs. per 1000 gal. water; compositions shown are "as mixed".



Coalbed Methane Fields of Alabama (Pashin and Hinkle, 1997)

7/14/01 kk 1027-HF-BW-1.cdr

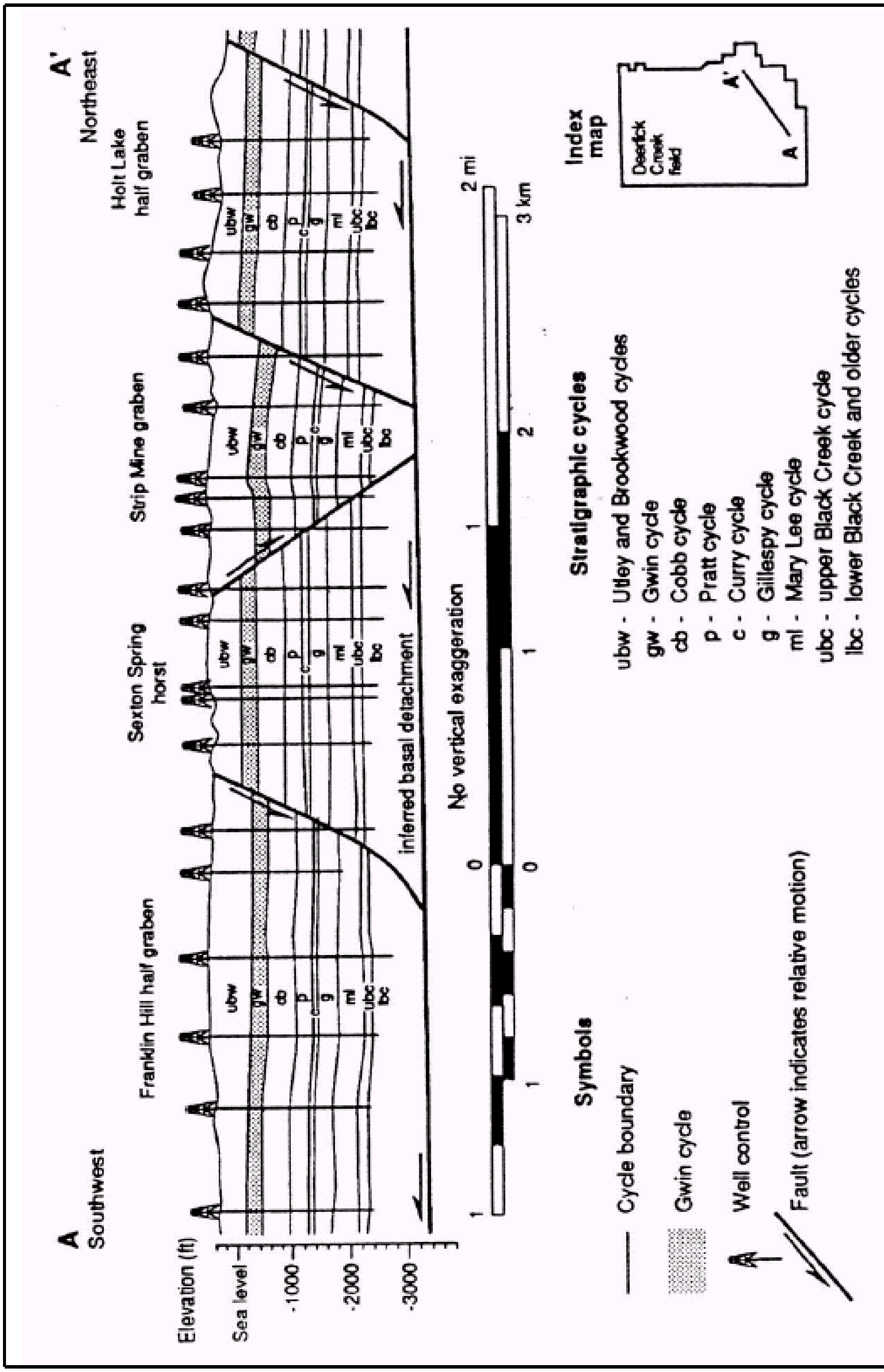
Figure A2-1



Coal Cycles of the Pottsville Formation in the Black Warrior Basin (Pashin and Hinkle, 1997)

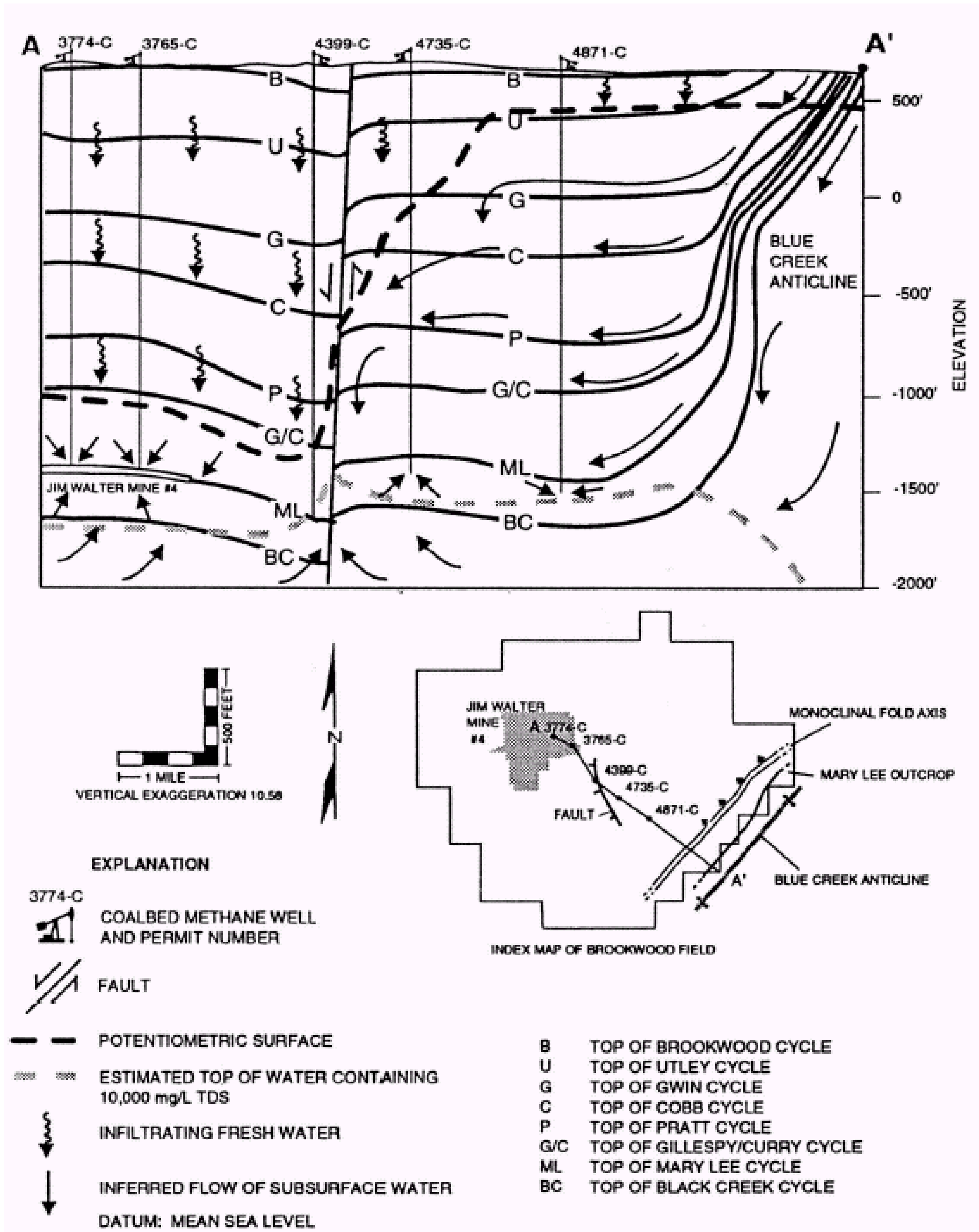
7/14/01 kk 1027-BW-2.cdr

Figure A2-2



Cross-Section of the Pottsville Formation in the Deerlick Creek Field (Pashin and Hinkle, 1997)

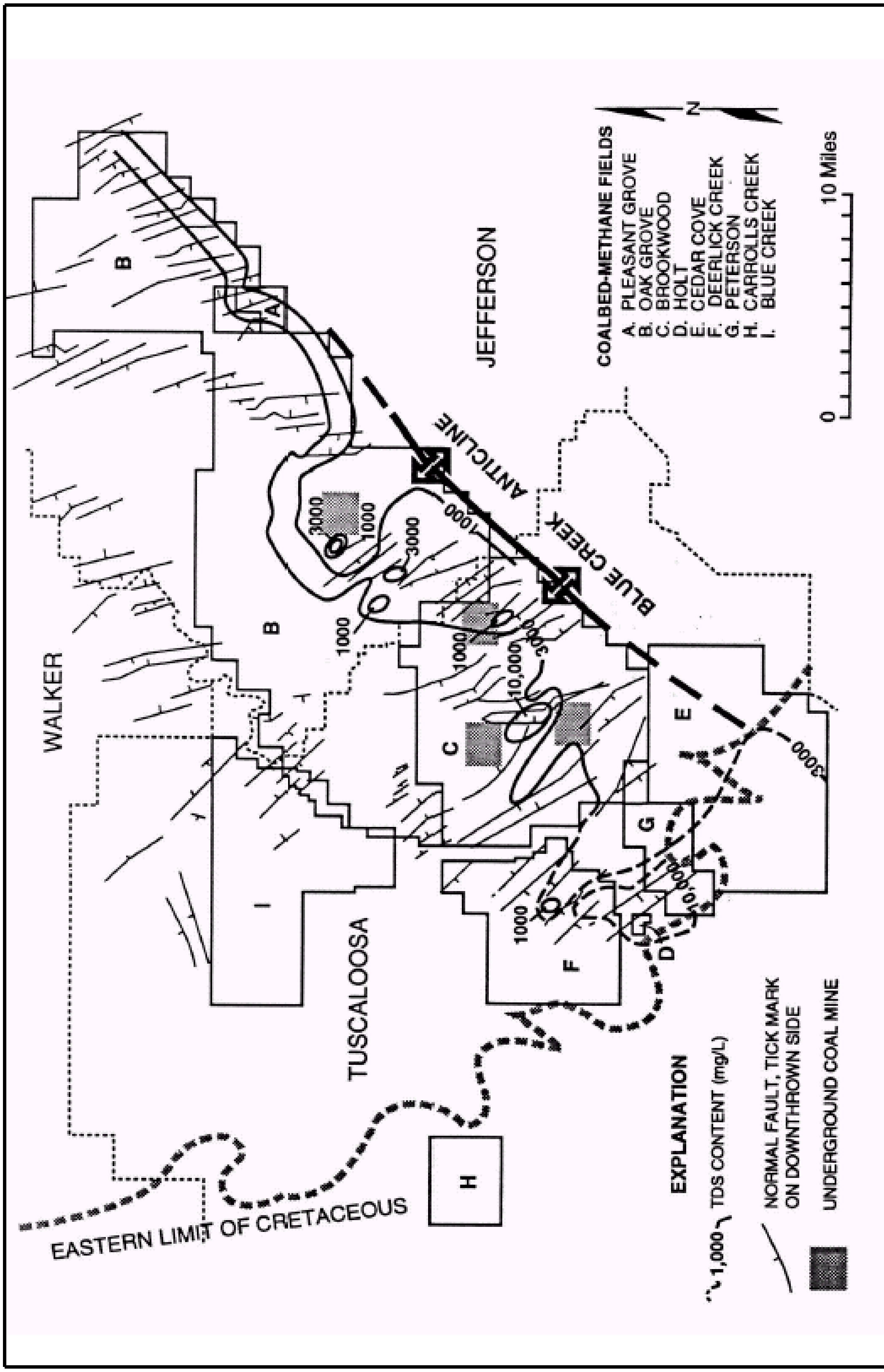
Figure A2-3



Hydrogeologic Cross-Section of the Pottsville Formation in the Brookwood Field
(see Figure 2-1 for Field Location) (Pashin and Hinkle, 1997)

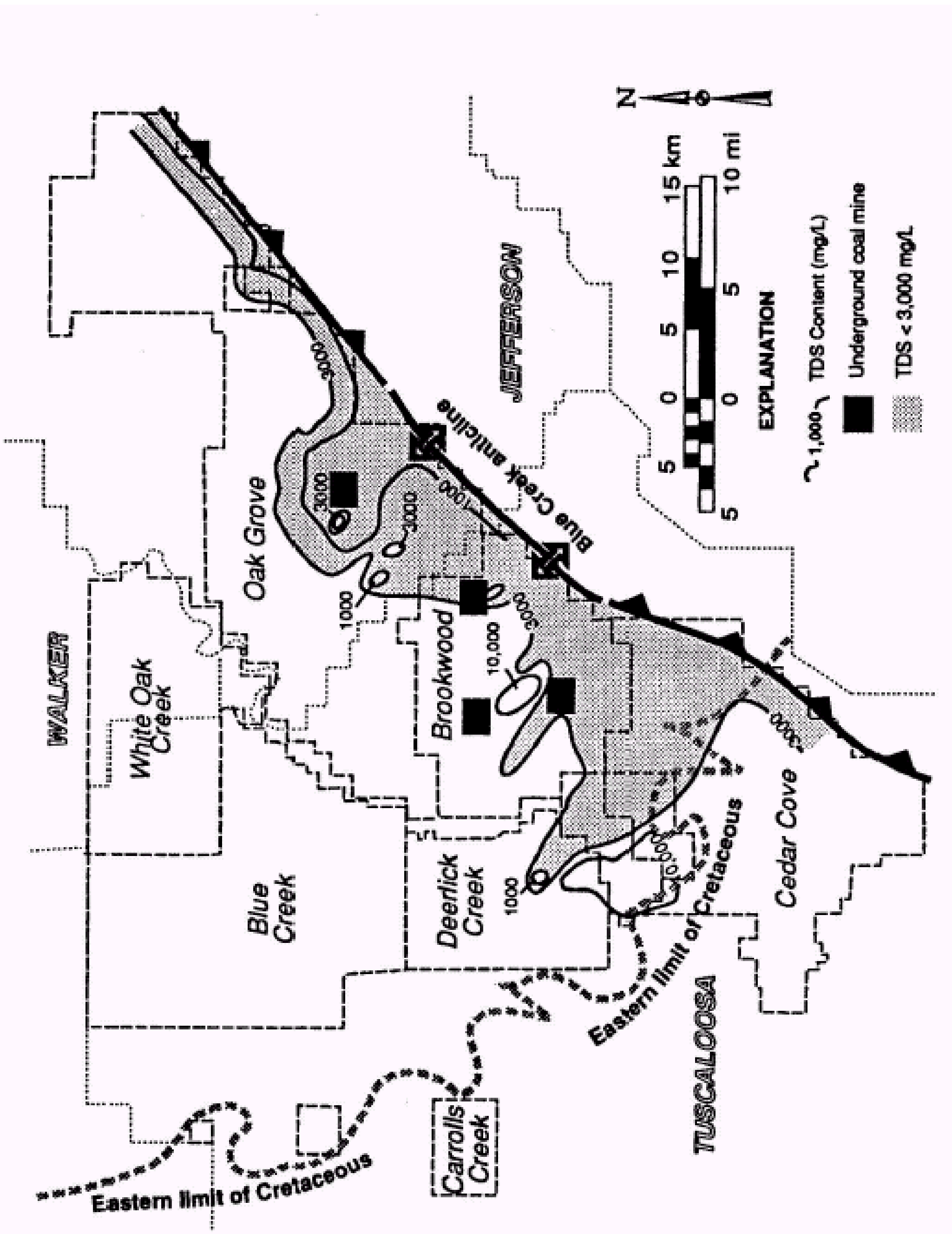
7/14/01 kk 1027-BW-4.cdr

Figure A2-4



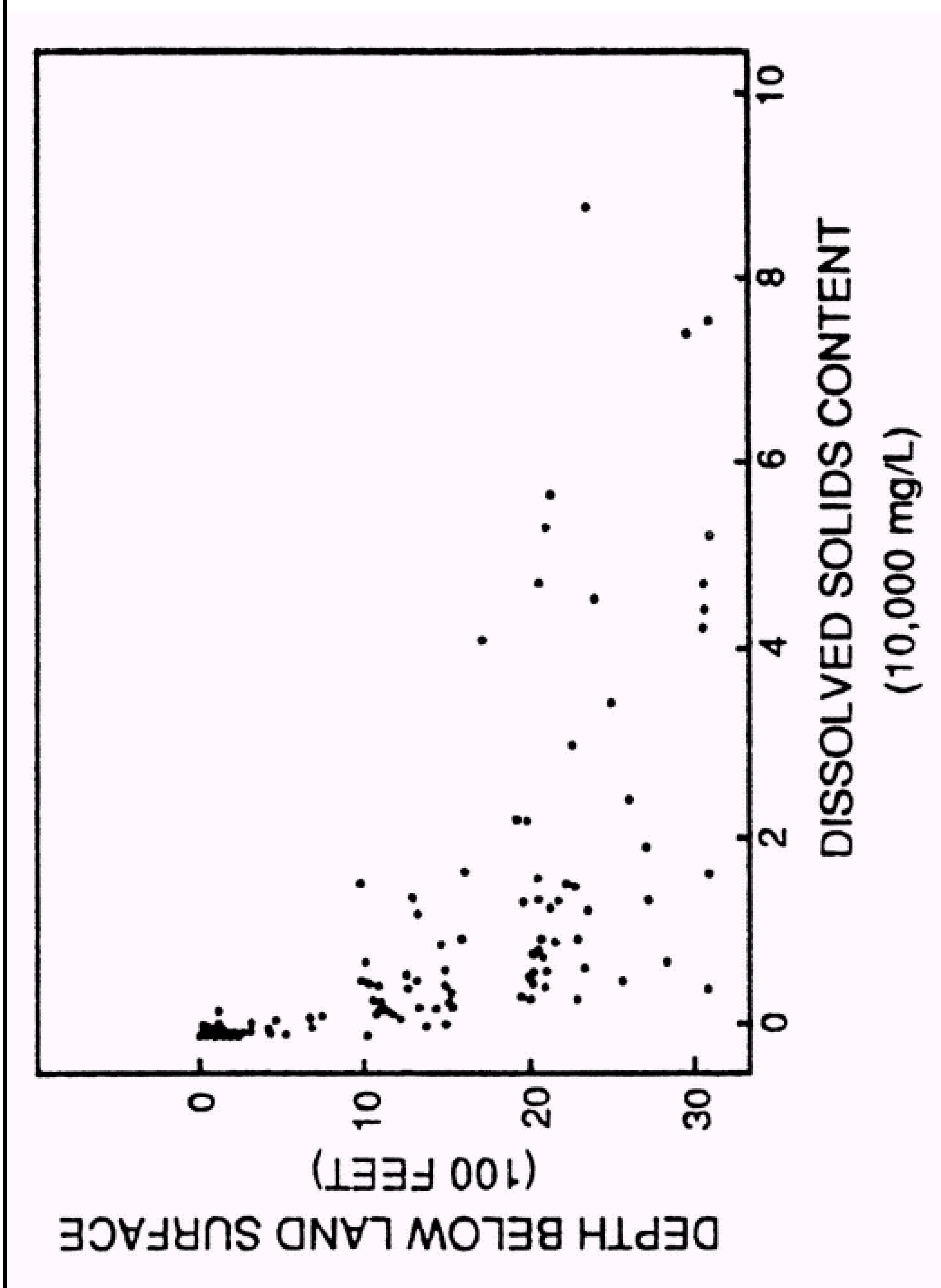
TDS concentration of Pottsville Aquifer, Black Warrior Basin, Alabama (Pashin and Hinkle, 1997)

Figure A2-5



TDS Concentration of the Mary Lee Coal Seam of the Pottsville Aquifer in the Eastern Part of the Black Warrior Basin, Alabama (Pashin et al., 1991)

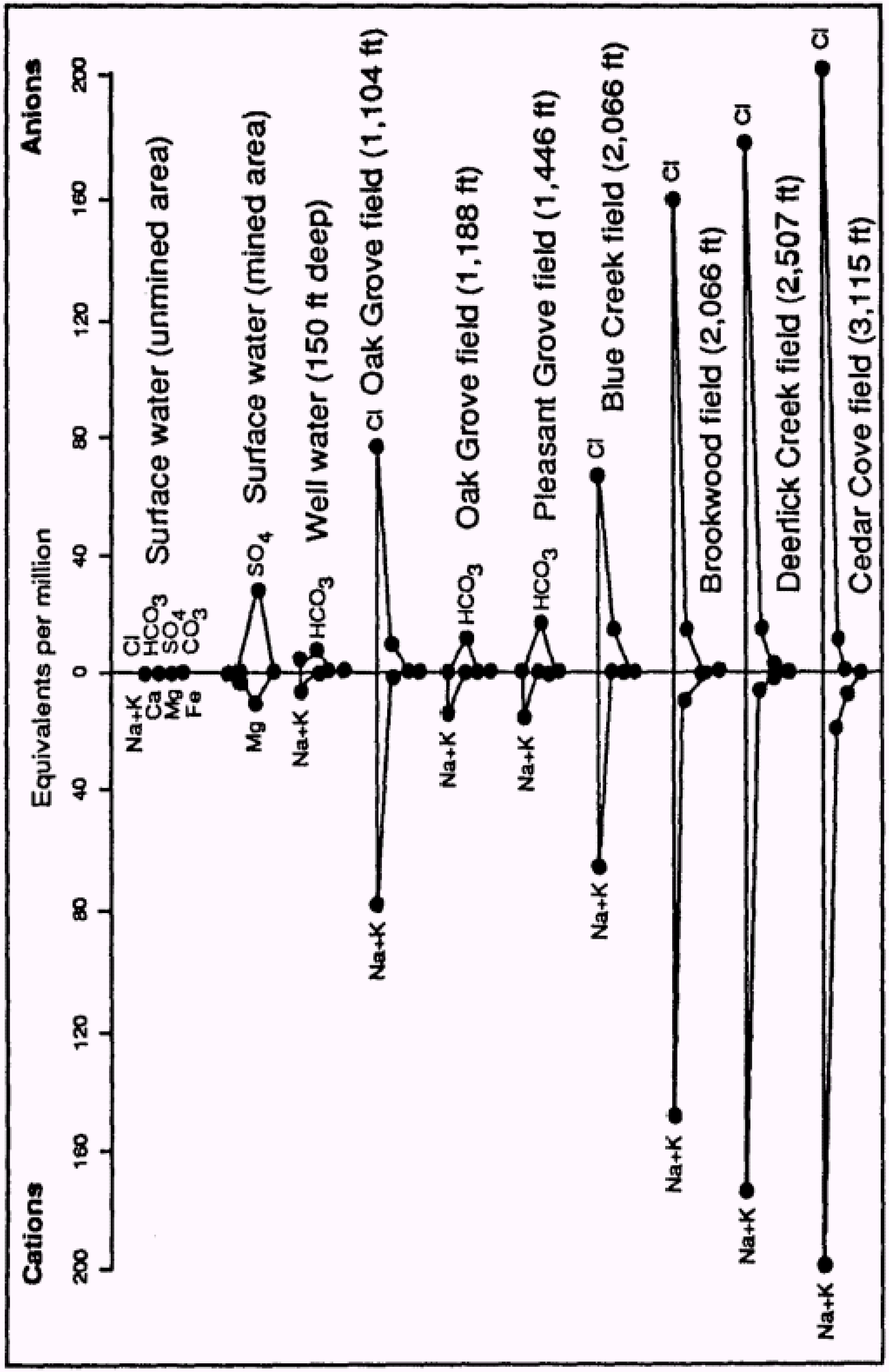
Figure A2-6



Generalized Increase in TDS Concentration with Depth in the Pottsville Aquifer
Black Warrior Basin, Alabama (Pashin et al., 1991)

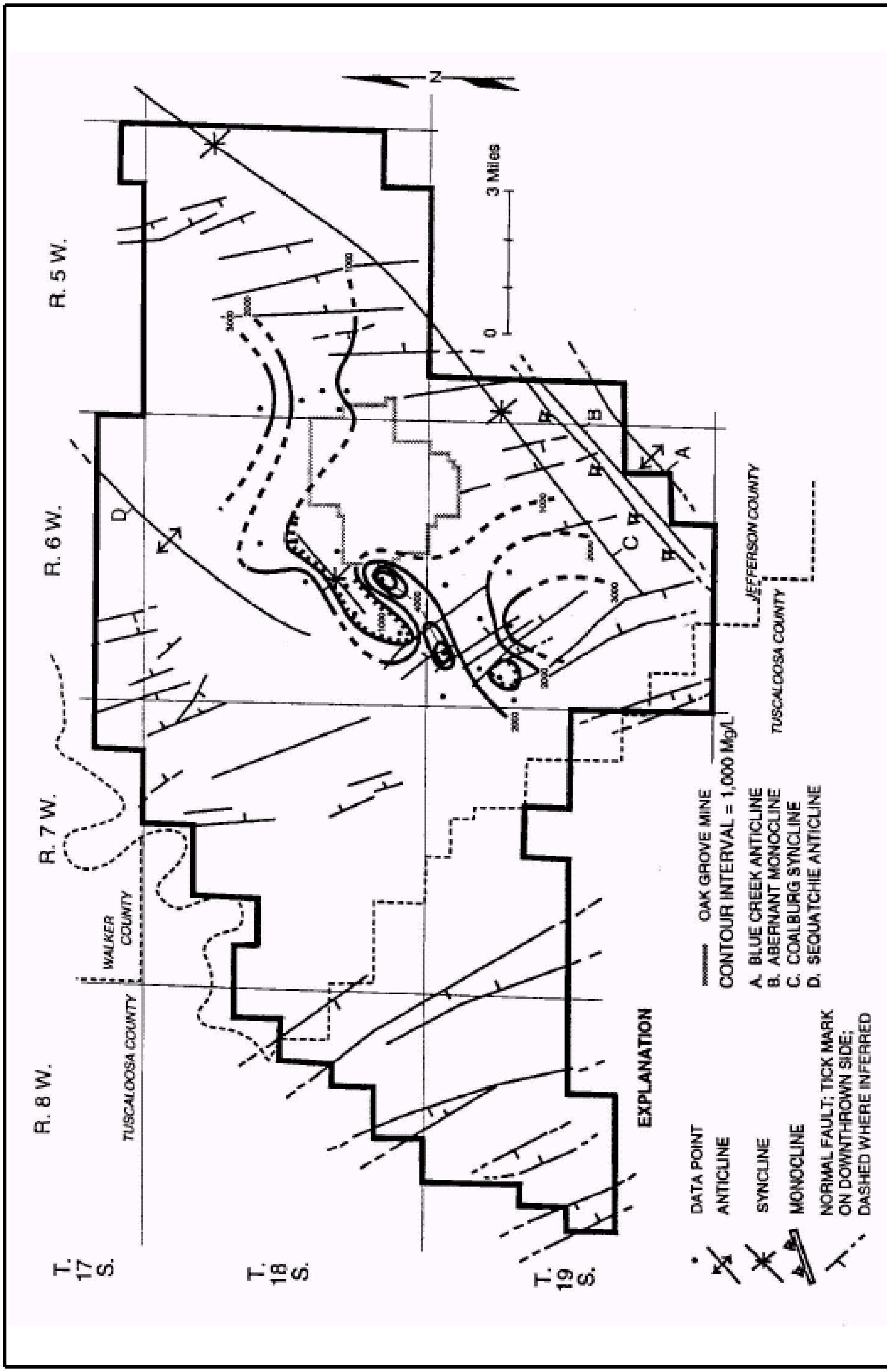
7/14/01 kk 1027-HF-BW-7.cdr

Figure A2-7



"Stiff" Diagram of Water Salinity (Pashin et al., 1991). The diagram indicates that most water samples contain less than 10,000 mg/L TDS (except near a few faults), and the salinity generally increases with depth in the Pottsville Aquifer, Alabama. Note that as mg/L of NaCl, the "Equivalent per Liter (epm)" units of the table correspond to 2337 mg/L (40 epm), 4675 mg/L (80 epm), 7012 mg/L (120 epm), 9350 mg/L (160 epm), and 11,688 mg/L (160 epm). NaClis, by far, the dominant species of most Pottsville water samples, and mg/L as NaCl closely approximates mg/L TDSs

Figure A2-8



Relationship of Water Salinity to Structural Features in the Oak Grove Field, Black Warrior Basin, Alabama (Pashin and Hinkle, 1997).
In general, water containing more than 3,000 mg/L TDS is related to upwelling of saline water near a few geologic faults

Figure A2-9

Field*	Number of Producing Groups	Coal Group	Depth Range (ft)	Number of Separate Stimulations
Oak Grove	2 or 3	Pratt Mary Lee** Black Creek	500–2500	2 or 3
Deerlick Creek (Lambert et al., 1987, 1990)	3		1000–3000	3
Cedar Cove (Sparks and Richardson, 1991)	4	Cobb Pratt Mary Lee** Black Creek	2000–3500	4
Moundville (Ely et al., 1990)	Up to 6 or 7†	Brookwood Utley Gwin Cobb Pratt Mary Lee** Black Creek	3000–5000	3–6

Productive Coal Seams and the Typical Number of Stimulations Per Well as of 1993, Black Warrior Basin, Alabama (Palmer et al., 1993)

7/14/01 kk 1027-HF-BW-10.cdr

Figure A2-10

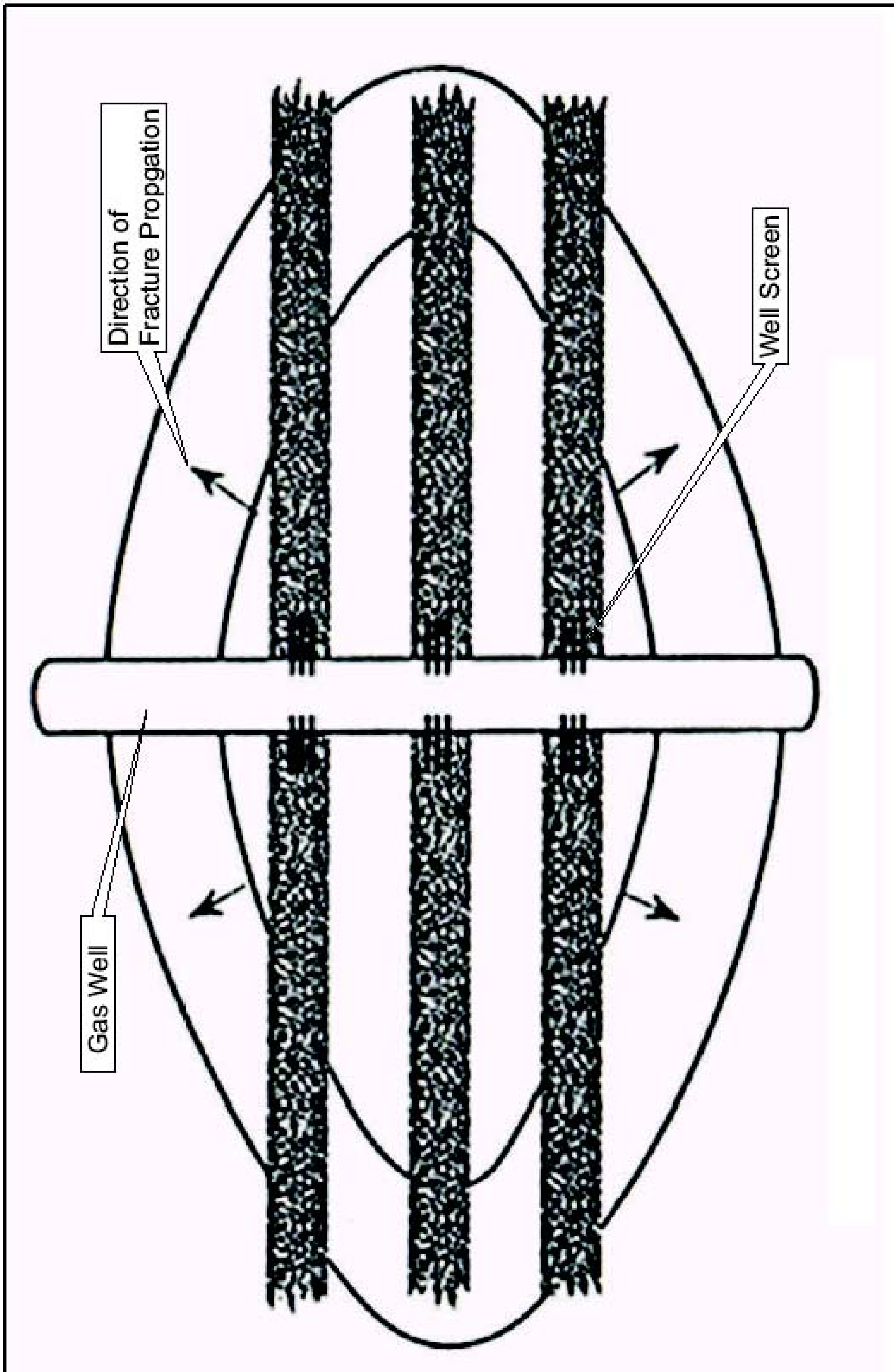


Figure A2-11

Sketch of a Vertical, Unconfined Fracture Typical of the Black Warrior Basin (Palmer et al., 1991)

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SPE = Society of Petroleum Engineers

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Attachment 3
The Piceance Basin

The Piceance Coal Basin is entirely within the northwest corner of Colorado. (Figure A3-1). The coalbed methane reservoirs are found in the Upper Cretaceous Mesaverde Group, which covers about 7,225 square miles and ranges in thickness from about 2,000 feet on the west to about 6,500 feet on the east side of the basin (Johnson, 1989). It is estimated that 80 trillion to 136 trillion cubic feet (Tcf) of gas are contained in coalbeds within the basin (Tyler et al., 1998). Total coalbed methane production was 1.2 billion cubic feet in 2000 (GTI, 2002).

3.1 Basin Geology

The Piceance is a northwest trending asymmetrical, Laramide-age basin in the Rocky Mountain foreland with gently dipping western and southwestern flanks and a sharply upturned eastern flank (Figure A3-1) (Tremain and Tyler, 1997). The Douglas Creek Arch bounds the basin on the northwest, and separates it from the Uinta Coal Basin, which lies almost entirely in Utah. The Mesaverde Group is sharply upturned to near vertical along the Grand Hogback, which forms the eastern boundary of the basin and separates the basin from the White River uplift to the east. Most of the Piceance Basin's coal deposits are contained in the Iles and Williams Fork Formations of the Late Cretaceous Age Mesaverde Group, which are approximately 100 to 65 million years in age (McFall et al., 1986). These formations composed of sandstone and shale, were deposited in a series of regressive marine environments (McFall et al., 1986; Johnson, 1989). It is believed that the coals were deposited in marine transitional, brackish, interdistributary marshes and freshwater deltaic swamps (Collins, 1976 in McFall et al., 1986). Figure A3-2 presents a stratigraphic section shown with a gamma ray-induction log from the Barrett 1-27 Arco Deep well (Reinecke et al., 1991). The Mesaverde Group is underlain by the marine Mancos Shale and overlain by the lower Tertiary Age Fort Union and Wasatch Formations, which consist of fluvial sandstones and shales. The Mancos Shale, Fort Union, and Wasatch Formations are essentially barren of coals (McFall et al., 1986). Depths to the coal-bearing sediments vary from outcrops around the margins of the basin (Figure A3-1) to more than 12,000 feet in the deepest part of the basin (Tyler et al., 1996).

The major fold structure of the Piceance Basin is the Grand Hogback Monocline, formed as the White River Uplift was uplifted and thrust westward during the Laramide Orogeny in Late Cretaceous through Eocene time (McFall et al., 1986). Broad folds, such as the Crystal Creek and Rangley Syncline, trend northwest to southeast, and generally parallel to the axis of the basin (Figure A3-1). Intrusions occur throughout the southeast part of the basin, locally elevating coal ranks to as high as anthracite grade. A buried laccolith intrusion is thought to be present under a coal basin anticline along the southeast margin of the basin (Figure A3-1) where high quality coking coal was mined since the 1800s (Collins, 1976).

Coalbed methane reservoirs occur exclusively in the Upper Cretaceous Mesaverde Group (Figure A3-2), which covers an area of approximately 7,255 square miles (Tremain and Tyler, 1997). Depths to the Mesaverde Group range from outcrop to greater than 12,000 feet along the axis of the basin (Tyler et al., 1996; Tremain and Tyler, 1997). Two-thirds of the coalbed methane occurs in coals deeper than 5,000 feet, making the Piceance Basin one of the deepest coalbed methane areas in the United States (Quarterly Review, August 1993).

The major coalbed methane target, the Cameo-Wheeler-Fairfield coal zone (Figure A3-3), is contained within the Williams Fork Formation of the Mesaverde Group and holds approximately 80 to 136 Tcf of coalbed methane (Tyler et al., 1998). This coal zone ranges in thickness from 300 to 600 feet, and lies more than 6,000 feet below the ground surface over a large portion of the basin (Tyler et al., 1998). Individual coal seams of up to 20 to 35 feet thick can be found within the group, with net coal thickness of the Williams Fork Formation averaging 80 to 150 feet thick. In 1991, at the Grand Valley field (Figure A3-4), there were 23 coalbed methane wells and 18 conventional gas wells (Reinecke et al., 1991). However, in 1984, most wells at the Rulison field (Figure A3-4) were conventional gas wells.

Initially, it was anticipated that coalbed methane wells in the sandstones and coals of the Cameo Zone would have high production rates of water. However, testing later showed that they produced very little water (Reinecke et al., 1991). Both the sandstones and coalbeds are tight, poorly permeable, and are generally saturated with gas rather than water or a mixture of water and gas. The dynamic flow of a hydrologic system enhances the collection of gas in traps, but in much of the Piceance Basin that flow is not present because of the over-pressuring and saturation with gas.

Consequently, the conventional models for coalbed methane accumulation developed for other basins do not apply well for exploration and development in the Piceance Basin. Tyler et al. (1996) concluded, “very low permeability and extensive hydrocarbon overpressure indicate that meteoric recharge, and, hence, hydropressure, is limited to the basin margins and that long-distance migration of groundwater is controlled by fault systems.” Recharge is limited along the eastern and northeastern margins of the basin because of offsetting faults, but zones of transition between hydropressure and hydrocarbon overpressure in the western part of the basin and on the flanks of the Divide Creek Anticline in the southeastern part of the basin may possess better coalbed methane potential, as indicated by the exploration targets delineated in Tyler et al. (1998) (Figure A3-5).

3.2 Basin Hydrology and USDW Identification

The Piceance Basin contains both alluvial and bedrock aquifers. Unconsolidated alluvial aquifers are the most productive aquifers in the Piceance Basin. These alluvial deposits are narrow, and thin deposits of sand and gravel formed primarily along stream courses. The City of Meeker, Colorado is supplied by wells tapping these deposits where they are over 100 feet thick in the White River Valley (Taylor, 1987).

The most important bedrock aquifers are known as the upper and lower Piceance Basin aquifer systems. These consolidated rock aquifers are lower Tertiary Eocene in age and occur within and above the large oil shale reserves. The upper and lower aquifers are separated by the Mahogany Zone of the Parachute Creek Member (Figure A3-6). The Mahogany Zone is a poorly permeable oil shale, which retards water movement but does not stop it. Both bedrock aquifers overlie the older Cretaceous Mesaverde Group where the coal and coalbed methane are located.

The upper aquifer system is about 700 feet thick and consists of several permeable zones in the Eocene Uinta Formation and the upper part of the Parachute Creek Member of the Eocene Green River Formation. Sub-aquifers of the Uinta Formations are silty sandstone and siltstone, while those of the Parachute Creek Member of the Green River Formation are fractured dolomite marlstone. There is some primary porosity (i.e., the porosity preserved from during or shortly after sediment deposition, such as the spaces between grains) in the sandstone and the permeability of the sub-aquifers has been enhanced by natural fracturing that occurred during post-deposition deformation. Layers between the individual sub-aquifers are less permeable than the sub-aquifers themselves, but they do not prevent water movement between the sub-aquifers.

The lower aquifer system is about 900 feet thick and consists of a fractured dolomitic marlstone of part of the lower Parachute Creek Member of the Green River Formation. It is semi-confined below the Mahogany Zone and above the Garden Gulch Member of the Green River Formation and a high resistivity zone just above it (USGS, 1984 and Taylor, 1987) (Figure A3-6). Fracturing during deformation of the rocks and subsequent solution enlargement owing to dissolution of soluble evaporite minerals has increased permeability of this lower aquifer system.

Groundwater is recharged from snowmelt on high ground from where it travels down through the upper aquifer system, the Mahogany Zone, and into the lower aquifer system. The groundwater then moves laterally and/or upward discharging from both the upper and lower aquifer systems into streams (Figure A3-7). The minerals nahcolite ($NaHCO_3$), dawsonite ($NaAl(OH)_2CO_3$) and halite (NaCl) are present in the groundwater, and the circulation of the groundwater (with these minerals in solution) has caused enlargement of the natural fractures (Taylor, 1987). Water in the lower aquifer is reported to contain several hundred milligrams per liter (mg/L) of chloride (Taylor, 1987).

Wells in these two bedrock aquifer systems, the upper and lower Piceance Basin aquifers, typically range in depth from 500 to 2,000 feet and commonly produce between 2 to 500 gallons per minute of water (USGS, 1984). These Tertiary bedrock aquifers are stratigraphically separated from the base of the Cameo Coal Zone in the Cretaceous Mesaverde Group by from less than 1,500 feet of strata along the Douglas Creek Arch to more than 11,000 feet along the basin trough just west of the Grand Hogback (Johnson and Nuccio, 1986) (Figure A3-2).

Aquifer maps do not exist for the Piceance Basin, but water quality in the Piceance Basin is poor owing to nahcolite (sodium bicarbonate) deposits and salt beds within the basin (Graham, 2001). Only very shallow waters such as those from the surficial Green River Formation are used for drinking water (Graham, CDWR, 2001). In general, the potable water wells in the Piceance Basin extend no further than 200 feet in depth, based on well records maintained by the Colorado Division of Water Resources (CDWR). At least two wells in the area are approximately 1,000 feet in depth, but they are used for stock watering. A composite water quality sample taken from 4,637 to 5,430 feet deep within the Cameo Coal Group in the Williams Fork Formation exhibited a total dissolved solid (TDS) level of 15,500 mg/L, which is above the 10,000 TDS water quality criterion for a underground source of water (USDW) (Graham, CDWR, 2001). The produced water from coalbed methane extraction in the Piceance Basin is of such low quality that it must be disposed of in evaporation ponds or re-injected into the formation from which it came or at even greater depths (Tessin, 2001).

It is unlikely that any USDWs and coals targeted for methane production would coincide in this basin. These targeted coals are generally located at great depth, of at least 4,000 feet. The thousands of feet of stratigraphic separation between the coal gas bearing Cameo Zone and the lower aquifer system in the Green River Formation should prevent any of the effects from the hydrofracturing of gas-bearing strata from reaching either the upper or the lower bedrock aquifers.

Permeability of the coal and the surrounding sandstone and shale is generally quite low except near outcrop, creating little potential for these rocks to contain a USDW. Researchers (Reinecke et al., 1991) report that the permeability of gas-bearing coal and sandstone of the Cameo Zone is so low that the gas is over-pressured and has forced groundwater out of the zone, a condition that tends to disfavor the entrapment of methane. Tyler et al. (1998) state that high coalbed methane gas productivity requires geologic and hydrologic conditions, and that these conditions are not optimal throughout much of the Piceance Basin because of the absence of dynamic groundwater flow and the low permeability of the host rocks.

The above conditions prevail in the central part of the basin, previously favored as a coalbed methane development fairway, and heavily targeted for exploration (Nowak, 1991). However, analyses by Tyler et al. (1998) suggest that a transitional zone, between the deeply buried coal and the outcrops at the boundaries of the basin, where groundwater circulation may be sufficient to create more favorable trapping conditions (Figure A3-5), may be a better target area for coalbed methane production exploration. These exploration target zones could possibly have sufficient meteoric groundwater circulation to meet the water quality criterion of USDWs. However, Figure A3-3 shows that the depths to coals in the targeted methane producing zones (Figure A3-5) are greater than 4,000 feet below ground surface and therefore, are not likely to contain water that would meet the USDW quality criterion of less than 10,000 mg/L TDS. Currently, test-drilling information is insufficient to determine if this is the case. Nevertheless, due to the very low permeability, great depth, and expected poor water quality of the targeted coalbed methane producing zones, conflicts with USDWs are considered to be of very low probability.

3.3 Coalbed Methane Production Activity

Measurements of coal permeabilities in the Piceance Basin have shown that the deep coals typical of the basin are much less permeable than coals in top-producing coalbed methane basins such as the San Juan Basin in Colorado (Quarterly Review, 1993). Consequently, operators rely on large hydraulic fractures to produce coalbed methane from the deep, low permeability coals (Quarterly Review, 1993).

Exploration for coalbed methane began in the basin during the early 1980s, but viable commercial production did not begin until 1989 (Quarterly Review, 1993). The first well to commercially produce coalbed methane from the Piceance Basin, Exxon's Vega No. 2 well in Mesa County, went off-line in 1983 (Quarterly Review, 1993). Amoco Production Company attempted multi-well coalbed methane development in the late 1980s, and finally ceased activity in 1989. Commercial production was finally achieved in 1989 in the Parachute fields operated by Barrett Resources. Barrett Resources drilled 68 wells in 1990 and had planned for 22 more in 1991 (Western Oil World, 1991). The wells targeted both coals and sandstone within the Cameo Coal Zone and the Mesaverde sandstones, just above the Cameo coals. Other operators soon followed suit, including Fuelco at White River Dome field in the northern part of the basin (Figure A3-1), Conquest Oil Company near Barretts Resource's production in the central part of the basin, Chevron USA Inc., and many others. However, not all operators were successful in locating or producing coalbed gas. Ultimately, Barrett found the sandstones to be far more productive than the coalbeds, and attempts to complete wells in the coalbeds were largely abandoned.

According to the Colorado Geological Survey (2002), some operators are having success in their pilot coalbed methane production program in White River Dome Field northwest of Meeker. Their success is attributed to the extensive natural fracturing found in the coal seams at White River Dome. Fracturing may be particularly extensive as a result of the formation of the White River anticline and the proximity to the large Danforth Hills Mesaverde outcrop. As a result, operators are taking another look at coalbed methane development in the Piceance Basin. In addition, one of the operators is drilling (but not fracturing) horizontal wells in the coal seams to take advantage of the anomalous natural fracturing found at White River Dome field. In some areas of coalbed methane potential, horizontal well technology may replace hydraulic fracturing as a method to enhance coalbed methane well performance.

Within the Cameo Coal Zone, Barrett Resources typically used 3,000 to 3,500 barrels of gelled 2% potassium chloride water with 273,000 to 437,000 pounds of sand over a maximum 450 feet of the Cameo Coal Zone to stimulate coalbed methane wells (Quarterly Review, 1993). It was shown that these hydraulic stimulations created short (100-foot), multiple fractures around the wells (Quarterly Review, August 1993). Fuel Resources Development Company used 3,000 to 10,000 barrels of gelled water and 200,000 to 1,300,000 pounds of sand to fracture their wells in the White River Dome Field (Quarterly Review, 1993). All but one of Conquest Oil Company's wells was hydraulically fractured with 1,500 barrels of water or cross-linked gel and 31,000 to 230,000 pounds of regular or resin-coated sand (Quarterly Review, 1993).

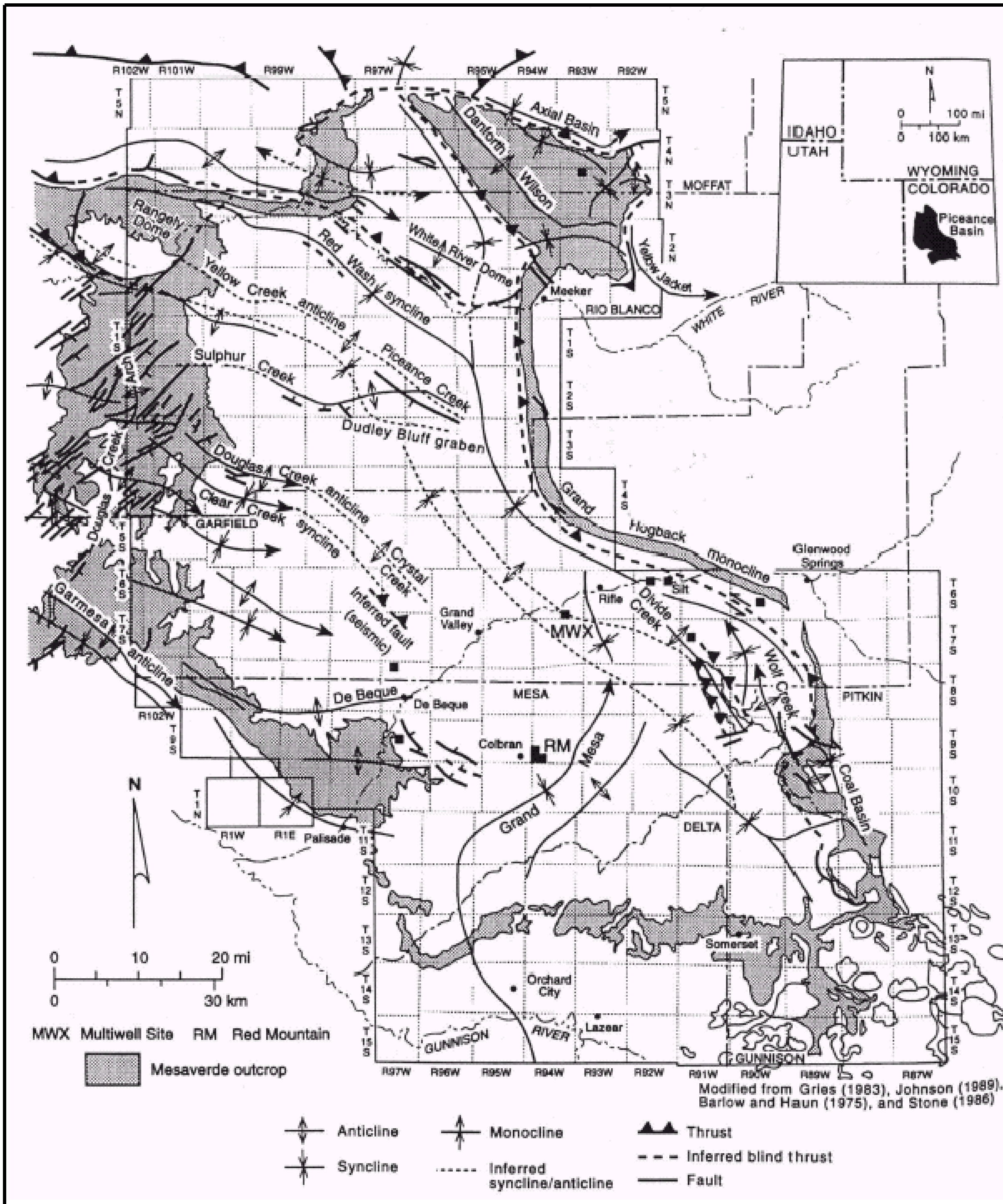
3.4 Summary

The Piceance Basin shows promise as a source for coalbed methane production based on the estimated 80 to 136 Tcf of gas contained within the Cameo-Wheeler-Fairfield coal zone (Tyler et al., 1998). However, overall low permeabilities as well as great depths to coalbeds appear to have slowed coalbed methane development in the basin. Nevertheless, a pilot program in White River Dome Field has had success in coalbed methane production, attributable primarily to the extensive natural fracturing in the area. As a result, operators are taking another look at coalbed methane development in this basin.

Hydraulic fracturing is the common method used to extract coalbed methane. Drilling of horizontal wells in the coal seams is a method that is being evaluated in the White River Dome Field pilot project as an alternative to hydraulic fracturing. In some areas of coalbed methane potential, horizontal well technology may replace hydraulic fracturing as a method to enhance coalbed methane performance.

The fluids used for fracturing vary from water with sand proppant to gelled water and sand. Between 1,500 to more than 11,000 feet of strata separate the coals from the shallow USDWs, indicating that the potential for water quality contamination from hydraulic fracturing techniques is minimal. The only hydraulic fracturing fluid contamination pathway to the USDWs might be through faults or fractures extending between the deep coal layers and the shallow aquifers. The occurrence of these fractures and faults has not been substantiated in any of the literature examined for this investigation.

Research suggests that exploration may target areas where groundwater circulation may enhance gas accumulation in the coal and associated sandstones (Tyler et al., 1998). Under these exploration and development conditions, a USDW located in shallower Cretaceous rocks near the margins of the basin, could be affected by hydraulic fracturing. The depth to methane-bearing coals (about 6,000 feet) seems to indicate that, in the Piceance Basin, the chances of contaminating any overlying, shallower USDWs (no deeper than 1,000 feet) from injection of hydraulic fracturing fluids and subsequent subsurface fluid transport are minimal. Potable wells in the Piceance Basin generally extend no further than 200 feet in depth. The coalbed methane producing Cameo Zone and the deepest known aquifer, the lower bedrock aquifer, have a stratigraphic separation of over 6,000 feet.



Tectonic Map of the Piceance Basin (Tremain and Tyler, 1997)

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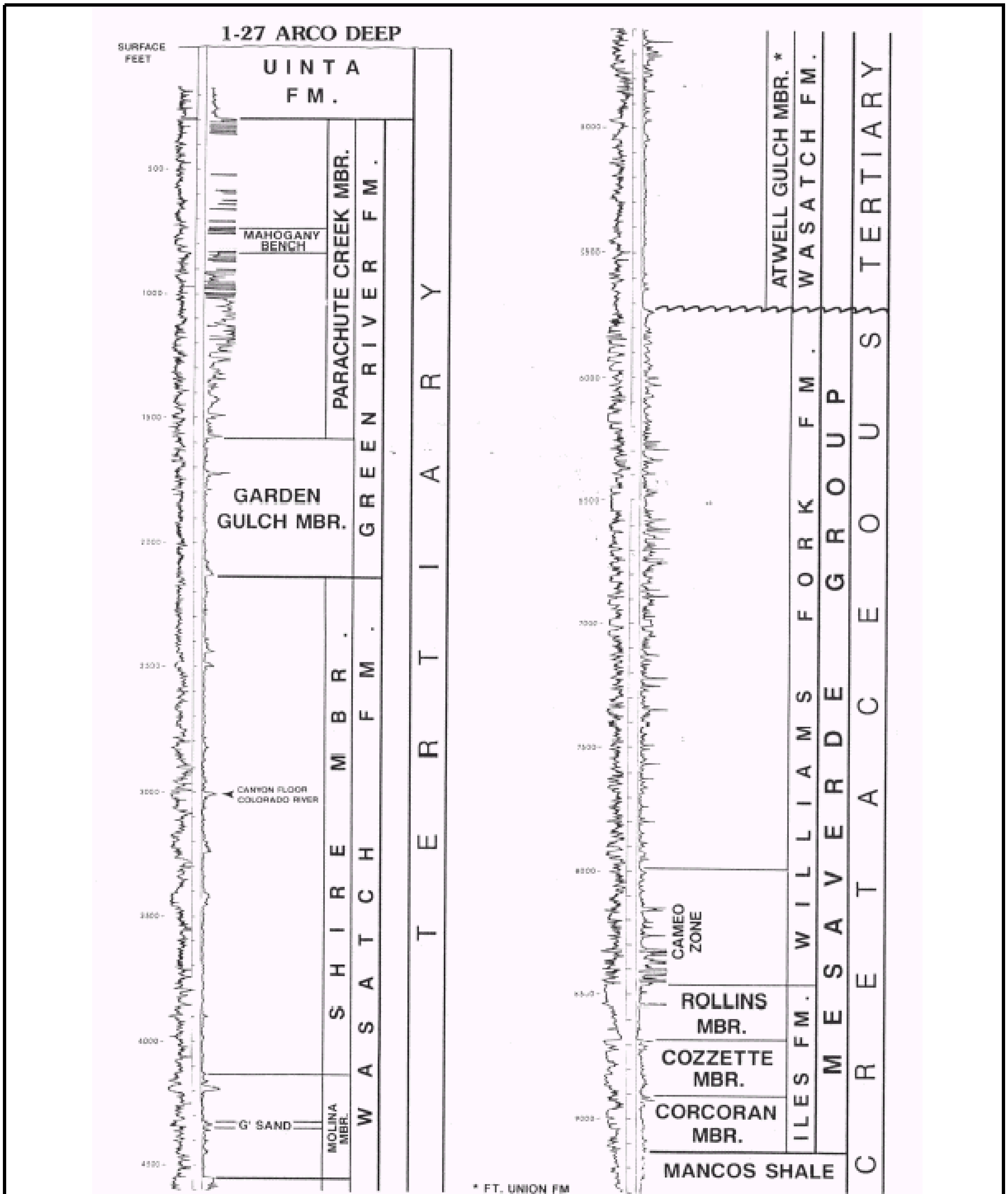
Figure A3-1



Stratigraphic Section of the Piceance Basin (Reinecke et al., 1991)

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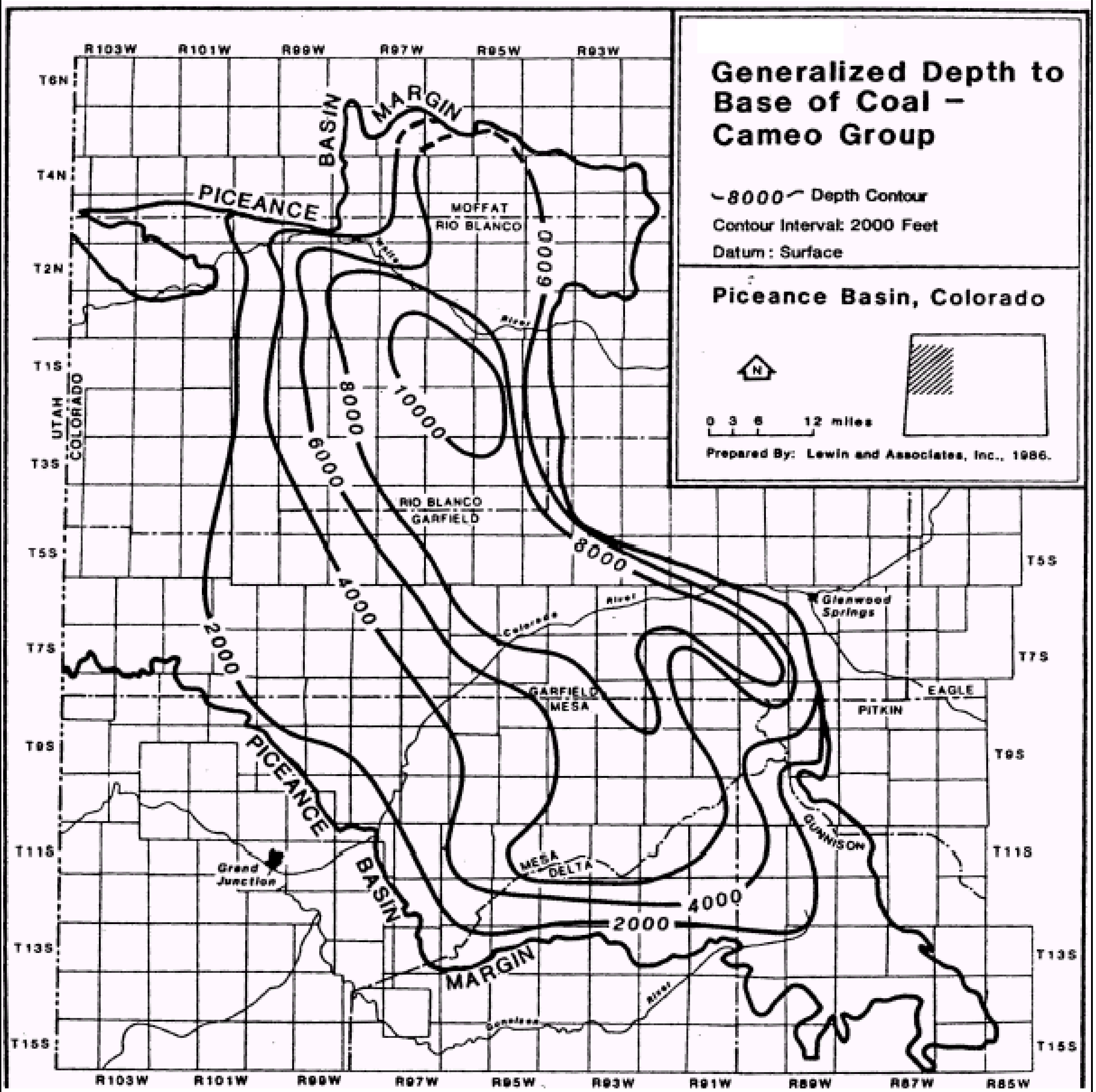
Figure A3-2



Generalized Depth to Base of Coal-Cameo Group (Lewin and Associates, Inc. 1986)

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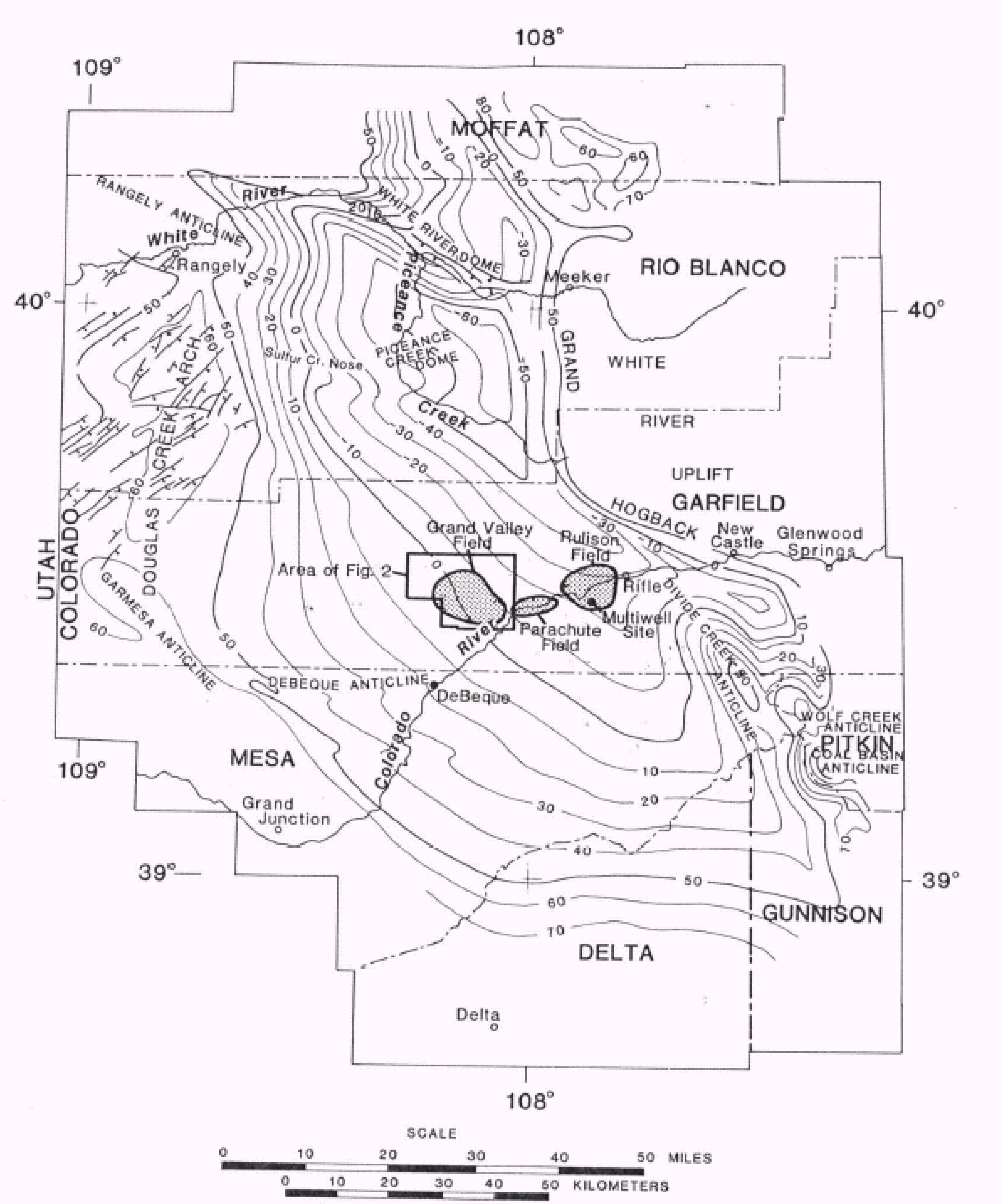
Figure A3-3



Locations of Gas Fields (Reinecke et al., 1991)

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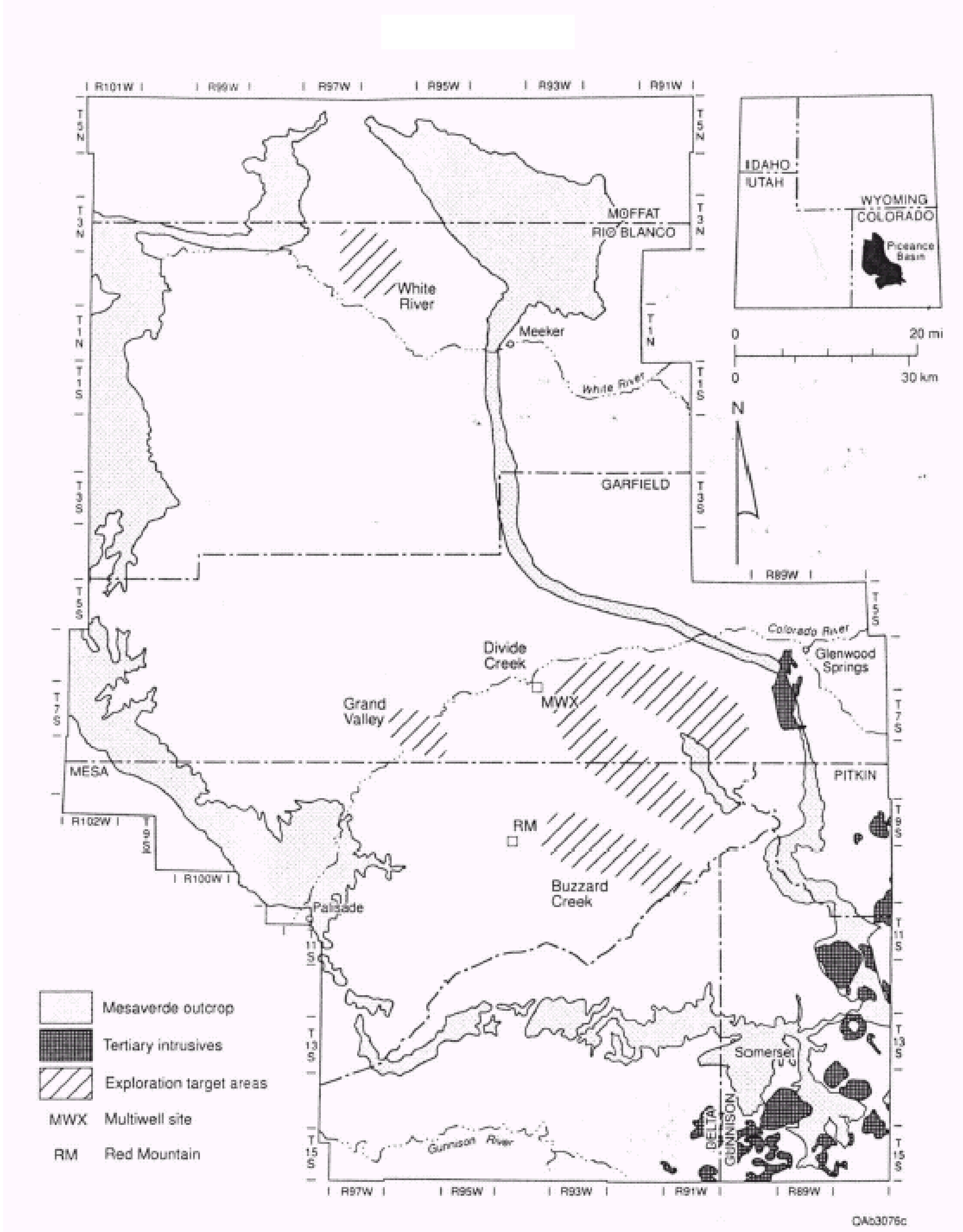
Figure A3-4



Exploration Target Areas, Piceance Basin (Tyler et al., 1998)

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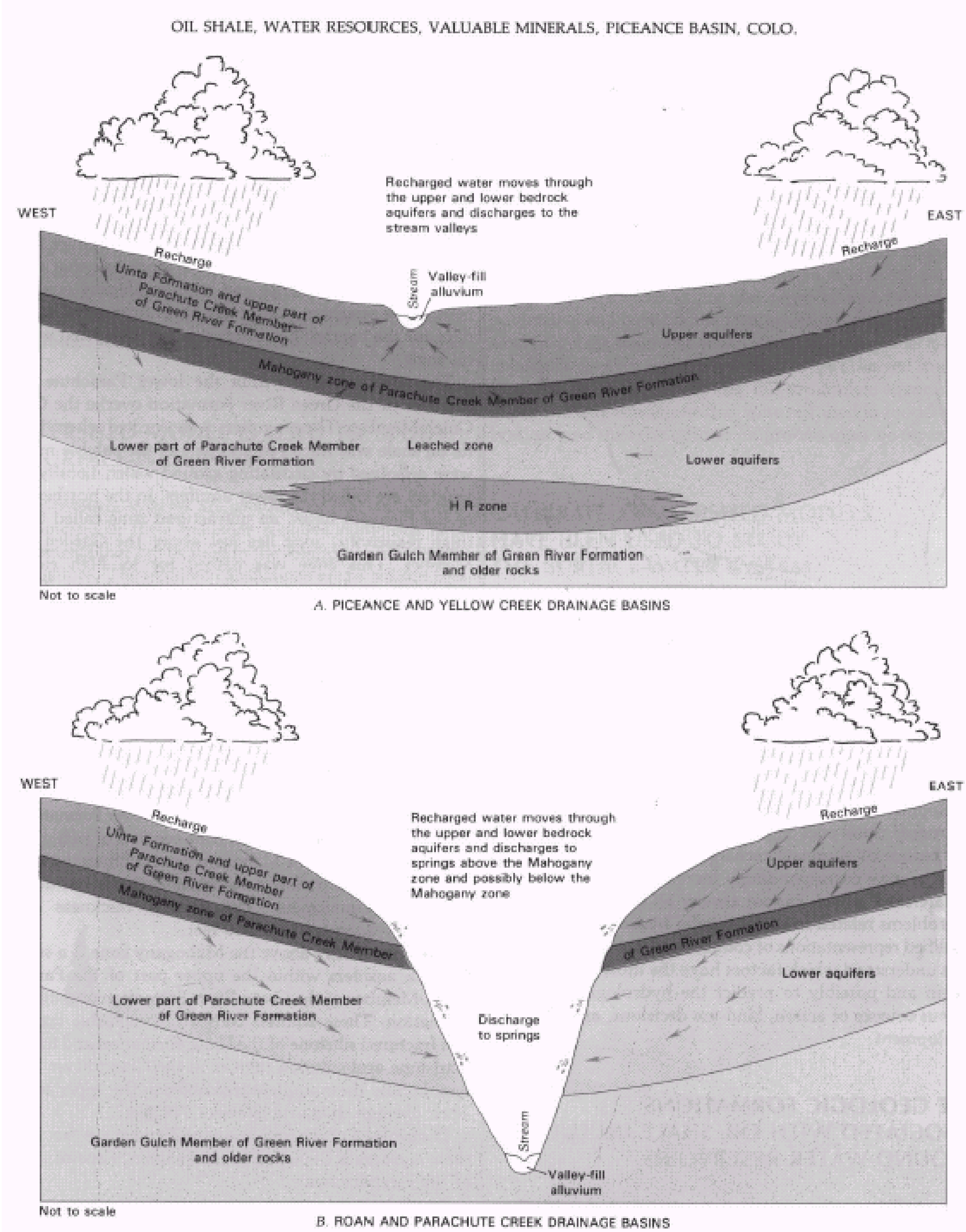
Figure A3-5



Diagrammatic East-West Sections of Hydrologic System (Taylor, 1987)

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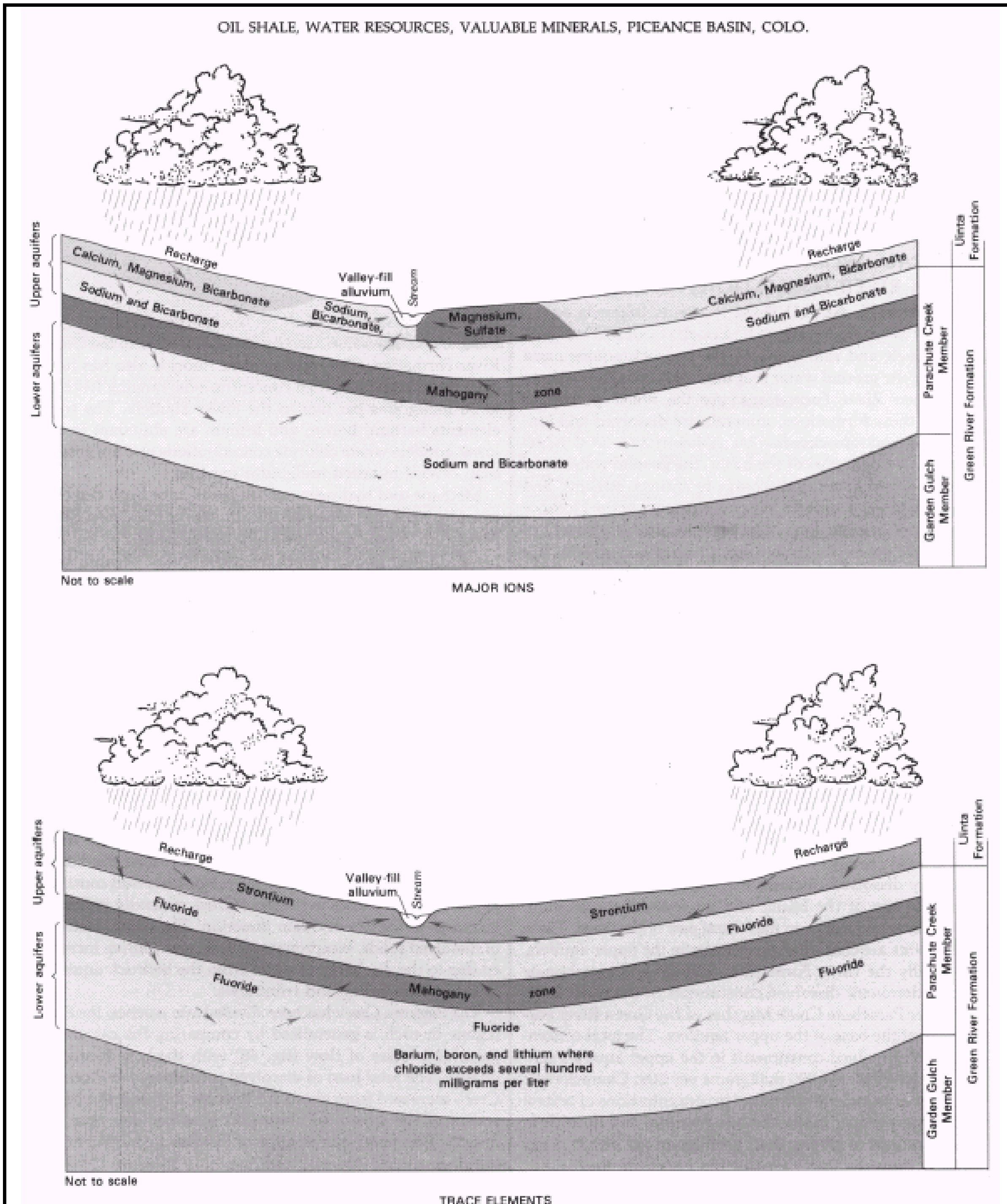
Figure A3-6



Dominant Chemical Constituents in the Two Major Bedrock Aquifers (Taylor, 1987)

7/14/01 kk 1027-HF-Piceance-7.cdr

Figure A3-7

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Attachment 4
The Uinta Basin

The Uinta Coal Basin is located mostly within eastern Utah; a very small portion of the basin is in northwestern Colorado (Figure A4-1). The basin covers approximately 14,450 square miles (Quarterly Review, 1993) and is structurally separated from the Piceance Basin by the Douglas Creek Arch (Figure A4-1), an up-warp near the Utah – Colorado state line. Coalbeds are present within Cretaceous strata throughout much of the Uinta Basin. However, coalbed methane exploration, to date, has targeted coalbeds in the Ferron Sandstone Member of the Mancos Shale and coalbeds in the Blackhawk Formation of the Mesaverde Group. The total, in-place, coalbed gas resources in the Wasatch Plateau, Emory, Book Cliffs and Sago coal fields have been estimated at 8 trillion cubic feet (Tcf) to more than 10 Tcf by the Utah Geological Survey (Gloyn and Sommer, 1993). This estimate is based on extrapolation of known coal resources to a depth of 9,000 feet and an average projected gas content of 330 cubic feet per ton and does not include the Tabby Mountain or Vernal coalfields, or the Sevier-Sanpete coal region. Total production stood at 75.7 billion cubic feet (Bcf) of coalbed methane in 2000 (GTI, 2002).

4.1 Basin Geology

Much of the Rocky Mountain region, including the Uinta Basin was covered by an epicontinental sea. Deposition in the sea lasted from the Albian (about 100 million years ago) through the Cenonmanian (about 83 million years ago), with the deposition of the upper part of the Mesaverde Group generally marking the end of marine deposition in the basin (Howells et al., 1987).

The Uinta Basin formed as a result of uplift and deformation that began in the Late Cretaceous. The Cretaceous sediments outcrop along the perimeter of the basin. The basin is asymmetrical in shape with strata on the northern flank of the basin dipping steeply toward the basin axis, while strata on the southern flank dip gently toward the basin axis. The stratigraphic units of the coal bearing Cretaceous rocks of the Uinta Basin are shown in Figure A4-2.

Two Cretaceous stratigraphic units have been targeted for coalbed methane exploration: the Ferron Sandstone Member of the Mancos Shale and the Blackhawk Formation of the Mesaverde Group (Figure A4-2). The Ferron Sandstone Member was deposited in the Last Chance delta, a fluvial-deltaic environment (Garrison et al., 1997). The coalbeds and interbedded sandstone units form a wedge of clastic sediment 150 to 750 feet thick stratigraphically above the Tunuck Shale Member of the Mancos Shale and below the Lower Blue Gate Shale Member of the Mancos Shale (Figure A4-2). Both of these shale units have a very low permeability and constitute confining units for water and gas in the Ferron Sandstone Member. The coal-bearing rocks are thickest to the west and south margins of the basin, nearer to the upland sources of sediment. Coalmines producing from the Ferron Sandstone Member are located along the eastern boundary of the Wasatch Plateau south of Castle Dale, Utah (Figure A4-1). Depths to coal in the Ferron Sandstone Member range from 1,000 to over 7,000 feet (Garrison et al., 1997). Primary coalbed methane activity from the Ferron Sandstone takes place in the Drunkard's Wash Unit. Total coal thickness in this area ranges from 4 to 48 feet (averaging 24 feet) from depths of 1,200 to 3,400 feet (Lamarre and Burns, 1996).

The Blackhawk Formation consists of coal interbedded with sandstone and a combination of shale and siltstone. The Blackhawk Formation is underlain by the Star Point Sandstone and overlain by the Castlegate Sandstone (Figure A4-2). The Castlegate Project in the Book Cliffs coalfield initially targeted coals in the Blackhawk Formation at depths ranging from 4,200 to 4,400 feet (Gloyn and Sommer, 1993).

4.2 Basin Hydrology and USDW Identification

Groundwater hydrology of the Uinta Basin is controlled primarily by the geologic structure of the region (Howells et al., 1987). Variations of aquifer and aquitard permeability owing to differences of lithology and facies changes also play an important role in the hydrology, as does widespread faulting and fracturing of the rocks (Howells et al., 1987). Because of the basin's structure, the area may be a groundwater basin with internal drainage. If there were a deep groundwater outlet for the basin, it would be along or near the axis of the Uinta Basin at its western edge. The general pattern of groundwater flow is centripetal, with water flowing inward from recharge areas at exposures of permeable strata at the margins of the basin. Recharge is greatest near the northern edge of the basin. Other recharge areas include Eocene and Oligocene Formations in the basin interior.

Most of the sandstone formations in the Mesozoic rocks in the Upper Colorado River Basin are identified as aquifers by the United States Geological Survey (Freethey and Cordy, 1991). Freethey and Cordy stated that in the Uinta Basin, the older and deeper aquifers in strata below the Ferron Sandstone Member, (for example, the Navajo-Nugget Aquifer, Entrada-Preuss Aquifer, Morrison Aquifer, and the Dakota Aquifer) generally contain very saline to briny water, with total dissolved solids (TDS) values greater than 10,000 milligrams per liter (mg/L). The water quality component of the underground source of drinking water (USDW) definition specifies that a USDW contain less than 10,000 mg/L of TDS. The Ferron Sandstone Member (Figure A4-3) is designated as a producing aquifer in east-central Utah (Freethey and Cordy, 1991). In regard to the Mesaverde Group Aquifer, which includes the Star Point Sandstone, the Blackhawk Formation, the Castlegate Sandstone and the Price River Formation, (Figure A4-3) Freethey and Cordy (1991), stated that, "water in these aquifers is more likely to be developed where the saturated thickness is large and the depth to the aquifer is less than 2,000 ft." They further stated that the margins of the Uinta Basin where these rocks are near the surface or outcrop is a possible location for development of groundwater with low enough TDS to be used for drinking water.

Wells in the Ferron Sandstone Member at the Drunkard's Wash coalbed methane field typically penetrate to depths ranging from 1,200 to 3,400 feet (Lamarre and Burns, 1996). An average water quality value of 13,120 mg/L TDS (Gwynn, 1998) for production waters that have been retained in catchment ponds suggests that these wells are not within a USDW. Gwynn (1998) however, does state that due to the ponding of the produced water in evaporation lagoons, the concentration of salts in these waters has probably increased from their original levels. This implies that these water quality data may not be useful in the confirmation of USDW qualifications. Quarterly Review (1993) reported that three wells producing gas and water from the Ferron Sandstone Member coalbeds in the Drunkard's Wash field yielded over 49,000 gallons of water per day with a TDS level of about 5,000 mg/L (sodium bicarbonate) during the first 2 to 3 months of operation. The Ferron Sandstone is hydrologically confined above and below by shale members of the Mancos Shale formation. Water produced from the Ferron Sandstone is thought to be connate water that was trapped in the sediment during coalification (Gloyn and Sommer, 1993). Hunt (Utah Division of Oil, Gas, and Mining, 2001) noted that there were no USDWs located immediately above the Ferron Sandstone Member due to the thick tongues of Mancos Shale that encapsulate the coal-bearing interval (Figure A4-2).

Beds targeted for methane gas exploration and production within the Blackhawk Formation are approximately 4,200 to 4,400 feet below the ground surface (Gloyn and Sommer, 1993). Coalbed gas production in the Castlegate Field accounted for less than 10 percent of the coalbed methane production in the Uinta Basin (Petzet, 1996). The average gas well producing from the coalbeds in the Blackhawk Formation (Castlegate field) yielded 318 barrels of water per day, and TDS levels of 5,489 mg/L have been measured in the produced waters (Gloyn and Sommer, 1993).

According to the State of Utah Department of Natural Resources (DNR), Division of Oil, Gas and Mining, the water quality in the Ferron and Blackhawk varies greatly with location, each having some TDS levels below and some above 10,000 mg/L (Utah DNR, 2002). In general, the quality of Blackhawk water is higher than that of Ferron water. The most recent Underground Injection Control application received for the Drunkard's Wash field (Ferron) showed a composite quality of input water to be about 31,000 mg/L TDS, and for the Castlegate field (Blackhawk) 9,286 mg/L TDS. At some locations, either formation member would not qualify as a USDW.

In the western part of the Uinta Basin, the Castlegate Sandstone, an aquifer, is separated from the Black Hawk Formation coalbeds by approximately 300 feet of alternating shale and sandstone (Utah DNR 2002). The Star Point Sandstone is located below approximately 400 feet of alternating sandstone and shale that underlies the bottom coal of the Black Hawk Formation. In some areas, the shale and sandstone underlying the Black Hawk coals are highly faulted. There is some potential that hydraulic fracturing fluids could be transported through natural fracture networks in these areas and reach the Star Point Sandstone. The relatively impermeable upper Blue Gate Shale Member of the Mancos Shale Further would prevent further downward migration.

In reference to the quality of water produced by the coalbed gas wells in both the Ferron Sandstone Member of the Mancos Shale and the Blackhawk Formation, Quarterly Review (1993) states: "Disposal of produced water does not appear to present a major environmental problem in the Uinta basin, unlike the San Juan and some other western basins. Rates are moderate, 200 to 300 barrels per day per well during early stages of production and TDS levels are not high (about 5,000 mg/L)." Because these TDS values are less than the 10,000 mg/L limit, both the Ferron Sandstone Member of the Mancos Shale and the Blackhawk Formation may qualify as USDWs.

Tabet (2001) suggests that coalbed methane extraction wells are not located in "producing" aquifers and that most of the potable water in the sparsely populated area is supplied by surface water and shallow alluvial aquifers.

4.3 Coalbed Methane Production Activity

Full-scale exploration in the Uinta Basin began in the 1990s (Quarterly Review, 1993). The most active operators at that time were PG&E Resources Company, the River Gas Corporation, Cockrell Oil Corporation, and Anadarko Petroleum Corporation. PG&E acquired the Castlegate Field, from Cockrell Oil (Gloyn and Sommer, 1993). Gas was produced from coalbeds in the Blackhawk Formation. The five wells initially drilled in the Castlegate Field were hydraulically fractured with 80,000 to 143,000 pounds of sand and unreported volumes of fluid. Other wells were to be fractured with a low-residue gel system to ensure breakdown within the reservoir (Quarterly Review, 1993).

The Castlegate field was off-line due to production water disposal problems (Tabet, 2001; and Hunt, Utah Division of Oil, Gas, and Mining, 2001). According, to the State of Utah DNR, Division of Oil, Gas and Mining, the field is now on production (Utah DNR, 2002).

The River Gas Corporation operates the Drunkard's Wash Unit, producing methane gas from coals within the Ferron Sandstone Member. The company reported that high fracture gradients hampered hydraulic fracturing stimulations using cross-linked borate gel with 250,000 pounds of proppant (Quarterly Review, 1993). Excessive proppant flowback resulted in one well where nitrogen foam was used for the fracturing. The Buzzard Bench Field, also producing gas from the Ferron Sandstone Member, was initially operated by Chandler & Associates, Inc. (Petzet, 1996) and is currently being managed by Texaco (Garrison et al., 1997).

A query of a database covering the Uinta Basin revealed that there are about 1,255 coalbed methane wells in production in the basin (Osborne, 2002). Gas Technology Institute (GTI) places the annual coalbed methane production in the Uinta Basin at 75.7 Bcf in 2000 (GTI, 2002).

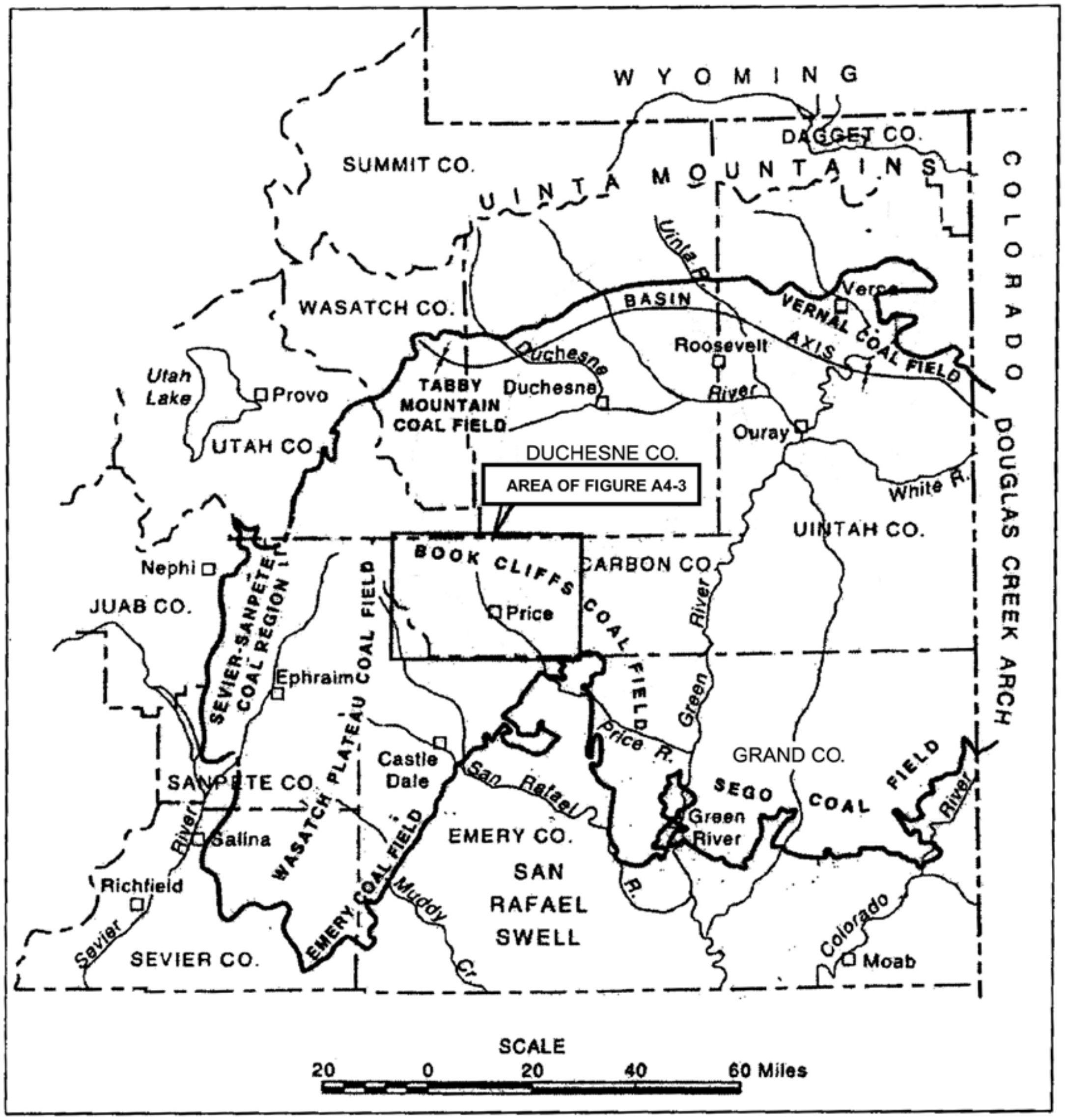
4.4 Summary

Waters from coalbed methane production in the Ferron Sandstone Member of the Mancos Shale in the Drunkard's Wash Unit are conflictingly reported to have TDS values of about 13,000 mg/L according to one source of information or to have levels of TDS of about 5,000 mg/L from another. However, the higher values were derived from water samples taken from evaporation lagoons and these high values might represent elevated concentrations of salts owing to evaporation. Consequently, if the more moderate TDS levels were correct, then the Ferron Sandstone would qualify as a USDW.

According to the State of Utah DNR, Division of Oil, Gas and Mining, the water quality in the Ferron and Blackhawk varies greatly with location, each having TDS levels below and above 10,000 mg/L (Utah DNR, 2002). In general, the quality of Blackhawk water is fresher than Ferron water. The most recent Underground Injection Control application received for the Drunkard's Wash field (Ferron) showed a composite quality of input water to be about 31,000 mg/L TDS, and for the Castlegate field (Blackhawk) 9,286 mg/L TDS. At some locations, neither formation member would qualify as a USDW.

The Drunkard's Wash and Castlegate coalbed methane extraction fields are located in a sparsely populated section of Utah. Tabet (Utah Geological Survey, 2001) suggests that coalbed gas extraction wells are not located in "producing" aquifers and that most of the potable water in the sparsely populated area is supplied by surface water and shallow alluvial aquifers.

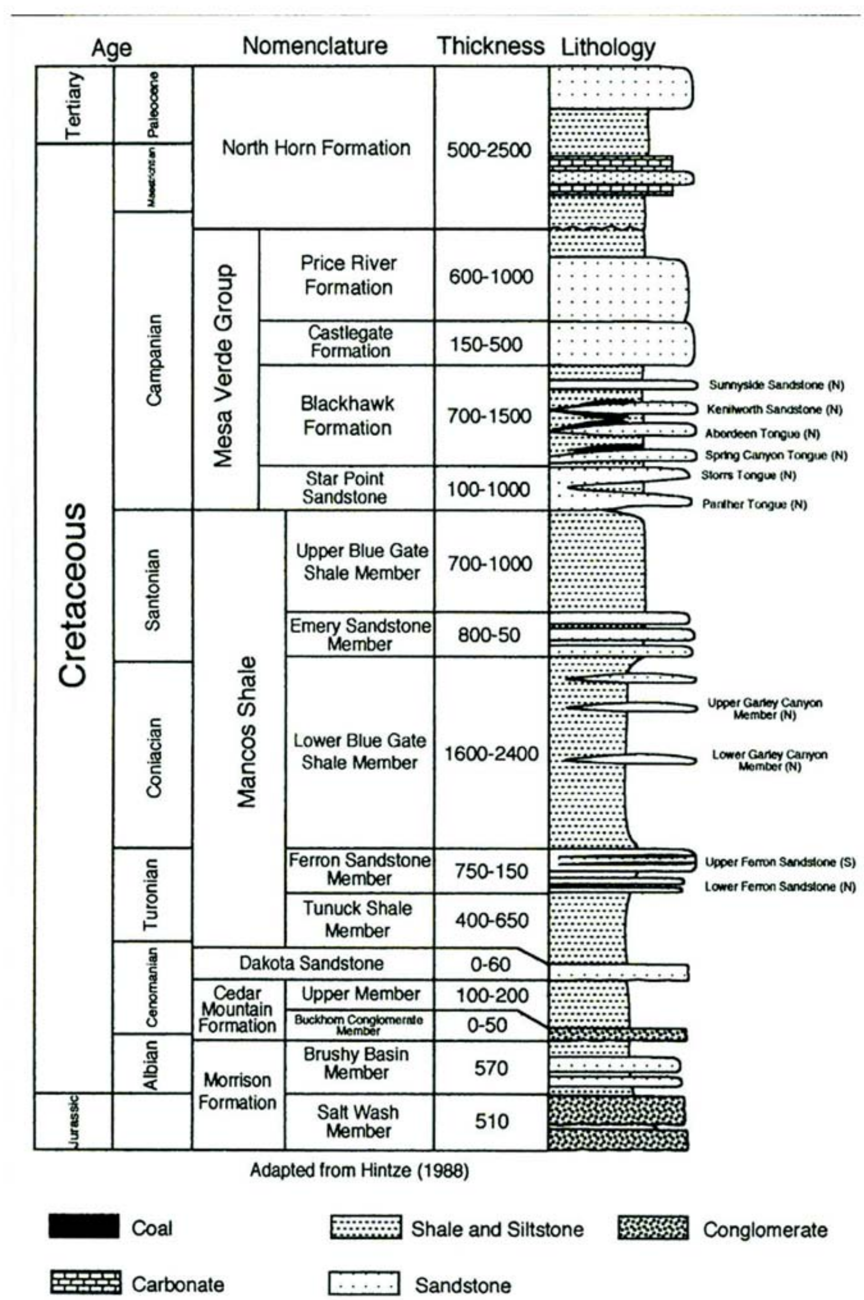
The Blackhawk Formation is underlain by 300 feet of shale and sandstone that separate it from the Castlegate Sandstone aquifer. It is underlain by similar geologic strata, which separate it for the Star Point Sandstone. Only in highly faulted areas is there a reasonable possibility that hydraulic fracturing fluids could migrate down to the Star Point Sandstone.



Index Map of Coal Fields in Uinta Basin, Utah (Quarterly Review, 1993)

7/14/01 kk 1027-HF-Uinta-1.cdr

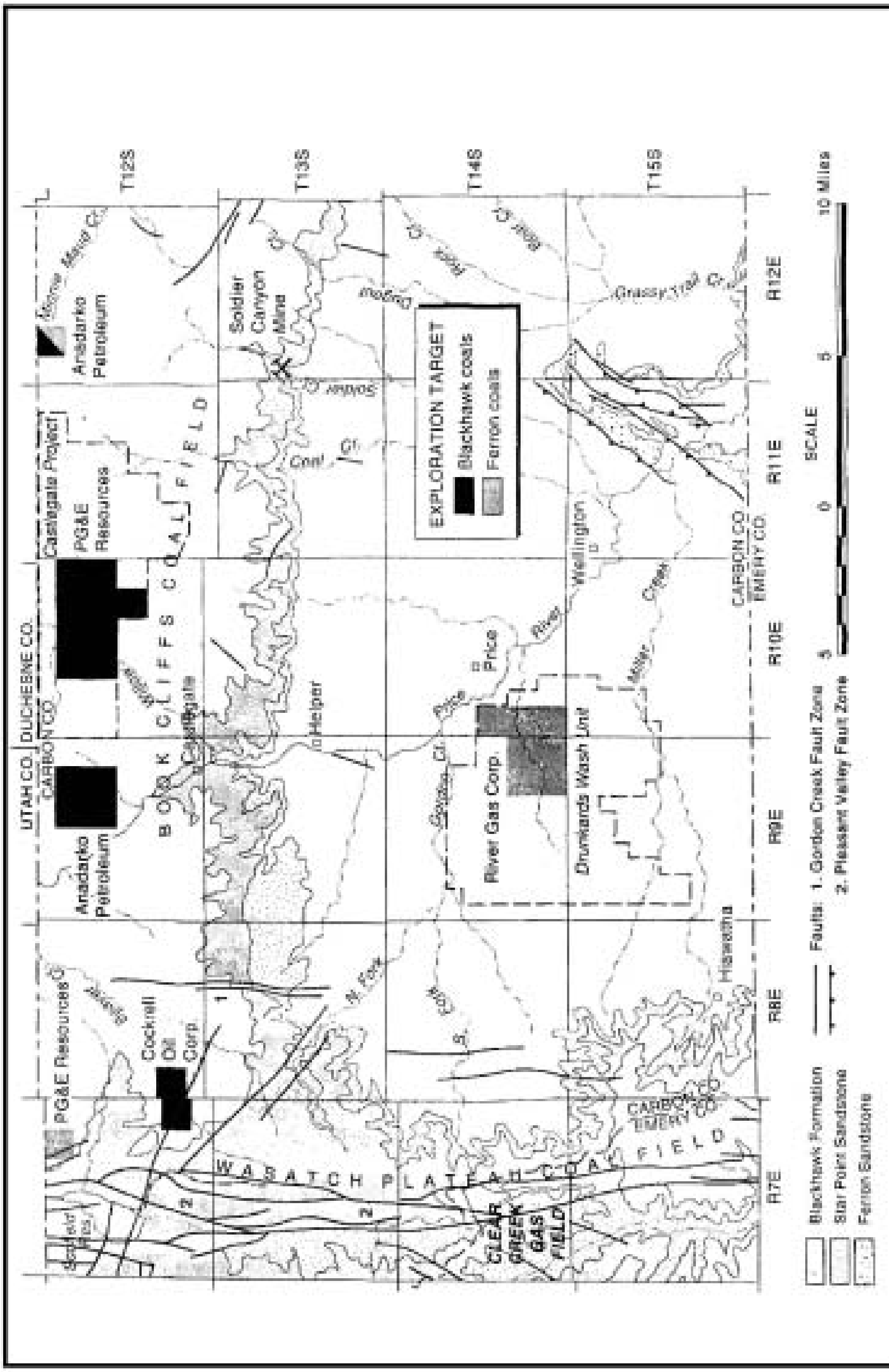
Figure A4-1



Stratigraphic Column for the Cretaceous of the Castle Valley (Garrison et al., 1997)

7/14/01 kk 1027-HF-Uinta-2.cdr

Figure A4-2



Coalbed Methane Development in Carbon County, Utah. (Methane from Coal Seams Technology, 1993)
Areas shown may not represent actual field, unit, or lease boundaries.

Figure A4-3

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Attachment 5
The Powder River Basin

The Powder River Basin is located in northeastern Wyoming and southern Montana. The basin covers an area of approximately 25,800 square miles (Larsen, 1989), approximately 75 percent of which is within Wyoming (Figure A5-1). Fifty percent of the basin (Figure A5-2) is believed to have the potential for production of coalbed methane (Powder River Coalbed Methane Information Council, 2000). Much of the coalbed methane-related activity has been north and south of Gillette in northeastern Wyoming (Figure A5-2). The majority of the potentially productive coal zones range from about 450 feet to over 6,500 feet below ground surface (Montgomery, 1999). In addition to being an important resource for coalbed methane, the basin has also produced coal, petroleum, conventional natural gas, and uranium oxide (Law et al., 1991; Randall, 1991). Recent estimates of coalbed methane reserves in the Powder River Basin have been as much as 40 trillion cubic feet (Tcf) (PRCMIC, 2000) but more conservative estimates range from 7 to 12 Tcf (Montgomery, 1999). Annual production volume was estimated at 147 billion cubic feet (Bcf) in 2000 (GTI, 2002). In 2002, wells in the Powder River Basin produced about 823 million cubic feet (Mcf) per day of coalbed methane (DOE, 2002).

The information available indicates that hydraulic fracturing currently is not widely used in this region due to concerns about the potential for increased groundwater flow into the coalbed methane production wells and collapse of open hole wells in coal upon dewatering. According to the available literature, where hydraulic fracturing has been used in this basin, it has not been an effective method for extracting methane.

5.1 Basin Geology

The Powder River Basin is a thick sequence of sedimentary rock formed in a large downwarp within the Precambrian basement. The basin is bounded on the east by the Black Hills uplift, on the west by the Big Horn uplift and Casper Arch, on the south by the Laramie and Hartville uplifts and, on the north, it is separated from the Williston Basin by the Miles City Arch and the Cedar Creek Anticline (Larsen, 1989) (Figure A5-1). The long axis of the basin is aligned in a generally southeast to northwest direction, and it is as much as 18,000 feet deep (Randall, 1991) (Figures A5-1 and A5-3). Sediments range from Paleozoic at the bottom through Mesozoic to Tertiary at the top (DeBruin et al., 2000). The basin is a large asymmetrical syncline with its axis (deepest part) near the west side of the basin (Figure A5-3). From outcrops along the eastern edge of the basin, the sediments slope gently (1.5^{o}, about 100 feet per mile) downward to the southwest and then bend steeply upward (10 to 45^{o}) to outcrop in a monocline along the western edge of the basin.

Several periods of deposition by marine and fluvial-deltaic processes have occurred within the basin during the Cretaceous and Tertiary periods. These Cretaceous and lower

Tertiary rocks have a total thickness of up to 15,000 feet (Montgomery, 1999). Coal is found in the Paleocene Fort Union and Eocene Wasatch Formations (Figure A5-4). The Wasatch Formation occurs at land surface in the central part of the basin and is covered by alluvium or White River Formation in some places (Figure A5-4). Most of the coalbeds in the Wasatch Formation are continuous and thin (six feet or less) although, locally, thicker deposits have been found (DeBruin et al., 2000). The Fort Union Formation lies directly below the Wasatch Formation and can be as much as 6,200 feet thick (Law et al. 1991). The Fort Union Formation outcrops at the ground surface on the eastern side of the basin, east of the City of Gillette and on the western side of the basin, north and south of Buffalo. The coalbeds in this formation are typically most abundant in the upper Tongue River Member (Figure A5-4). This member is typically 1,500 to 1,800 feet thick, of which up to a composite total of 350 feet of coal can be found in various beds. The thickest of the individual coalbeds is over 200 feet (Flores and Bader, 1999). The coalbeds are interspersed with sandstone, conglomerate, siltstone, mudstone and limestone (Montgomery, 1999).

Most coalbed methane wells in the Powder River Basin are in the Tongue River Member of the Fort Union Formation, in the Wyodak-Anderson coal zone, which contains up to 32 different coalbeds according to some authors (Ayers, 1986), including the Big George in the central part of the basin (Flores and Bader, 1999). The Wyodak is one of the thick coalbeds that are targeted for coalbed methane development. This coalbed is also called the Wyodak-Anderson or the Anderson, and it can be subdivided further into several other coalbeds. These coalbeds are the Canyon, Monarch, and Cook. All of these coalbeds are coalbed methane targets. Most coalbeds are found within 2,500 feet of the ground surface.

The Wyodak or Wyodak-Anderson coalbed in the Wyodak-Anderson coal zone is prominent in the eastern portion of the Powder River Basin near the City of Gillette (Figures A5-3, A5-5 and A5-6). The Wyodak has been identified as the largest single coalbed in the country (Montgomery, 1999). The coal is close to the ground surface and mining of the coal is common. The Wyodak coalbed gets progressively deeper and thicker toward the west. This bed ranges from 42 to 184 feet thick. Most of the coalbed methane wells in the Powder River Basin are within the Wyodak coal zone near the City of Gillette.

The Big George Coalbed is located in the central and western portion of the Powder River Basin (Figure A5-7). Although the Big George is stratigraphically higher than the Wyodak, owing to the structure of the basin, the Big George, in the center portion of the basin, is deeper than the Wyodak at the eastern margin of the basin (Tyler, et al., 1995). To date, the Big George has not been developed for coalbed methane production to the same extent as the Wyodak-Anderson coal zone. This is due to a combination of factors including greater depth to coal, more groundwater, and longer distances to available transmission pipelines. However, as of December 2001, there were about 850 coalbed methane wells drilled into the Big George with a large number of wells planned for the future (Osborne, 2002).

A third significant coal zone, the Lake De Smet coal zone in the Wasatch Formation, is up to 200 feet thick and is located in the Lake De Smet area (Figure A5-8), 55 miles southwest of Recluse on the western side of the basin (Larsen, 1989). It has not yet been widely used for coalbed methane production.

Most of the coal in the Powder River Basin is subbituminous in rank, which is indicative of a low level of maturity. Some lignite, lower in rank, has also been identified. The thermal content of the coals found in the Powder River Basin is typically 8,300 British thermal units per pound (Randall, 1991). Coal in the Powder River Basin was formed at relatively shallow depths and relatively low temperatures. Most of the methane generated under these conditions is biogenic, which means that it was formed by bacterial decomposition of organic matter. Thermogenic formation (formed under high temperature) was not significant in most locations within the Powder River Basin. Consequently, coal in the Powder River Basin contains less methane per unit volume than many other coal deposits in other parts of the country. Coal in the Powder River Basin has been found to contain 30 to 40 standard cubic feet of methane per ton of coal compared to 350 standard cubic feet of methane per ton in other areas (DeBruin et al., 2000). The gas is typically more than 95 percent methane, the remainder being mostly nitrogen and carbon dioxide. This resource was overlooked for many years because it was thought to be too shallow for the production of significant amounts of methane (Petzet, 1997). However, the relatively low gas content of Powder River Basin coal is compensated by the thickness of the coal deposits. Because of the thickness of the deposits and their accessibility, commercial development of the coalbed methane has been found to be economical.

The Powder River Basin contains approximately 60 percent of the coalbed methane reserves in the State of Wyoming (DeBruin et al., 2000). Recent estimates of coalbed methane reserves in the Powder River Basin have been as much as 40 Tcf (PRCMIC, 2000) but more conservative estimates range from 7 to 12 Tcf (Montgomery, 1999). As of December 1999, monthly production exceeded 7 Bcf from 1,657 wells (DeBruin et al., 2000). Wells typically produce 160,000 cubic feet of gas per day (DeBruin et al., 2000). Annual production volume was estimated at 147 Bcf in 2000 (GTI, 2002). In 2002, wells in the Powder River Basin produced about 823 Mcf per day of coalbed methane (DOE, 2002). Coalbed methane has been developed along both the east and west flanks of the basin where the coalbeds are buried but relatively shallow. Many existing wells are awaiting connection to the distribution system and still more wells are being drilled. The estimated lifetime production from these wells is 300 to 400 Mcf per well (Petzet, 1997).

The amount of coalbed methane produced from each well is highly variable, and the volume of gas depends on the quality and thickness of the coal, the frequency of natural cleats in the coal, and the amount of water present. Other factors, such as well completion techniques and well stimulation techniques, also control the amount of gas produced from a well. Maximum coalbed methane flow from a well is typically achieved after one to six months of dewatering (Montgomery, 1999). Stable production is usually experienced for one to two years before production begins to decline (Montgomery, 1999). Production often declines at a rate of 20 percent per year until the well is no longer economically useful (Montgomery, 1999). Several options exist at that point, including re-fracturing the well, completing the well in a deeper coal formation, converting the well to a water supply well, or abandoning the well.

5.2 Basin Hydrology and USDW Identification

A report prepared by the United States Geological Survey (USGS) showed that samples of water co-produced from 47 coalbed methane wells in the Powder River Basin all had total dissolved solids (TDS) levels of less than 10,000 milligrams per liter (mg/L) (Rice et al., 2000). Based on the water quality component of the underground source of drinking water (USDW) definition, which specifies that a USDW contain less than 10,000 mg/L of TDS, the Fort Union Formation coalbeds are within a USDW. The water produced by coalbed methane wells in the Powder River Coal Field commonly meets drinking water standards, and production waters such as these have been proposed as a separate or supplemental source for municipal drinking water in some areas (DeBruin et al., 2000). Sandstones in the sediments both above and below the coalbeds are also aquifers.

In 1990, Wyoming withdrew an average of 384 million gallons per day of groundwater for a variety of purposes, the majority of which was agriculture. Approximately 13 percent was used for potable water supplies. Approximately 22 percent was withdrawn by industry and mining (Brooks, 2001). The proportion of this 22 percent attributable to coalbed methane production is increasing rapidly, and a concern exists that such good quality water in a semiarid region should be conserved (Quarterly Review, 1993). In 1990, before the rapid expansion of coalbed methane extraction in the region, Campbell County was identified by the USGS as an area of major groundwater withdrawal.

Approximately 80 percent of Wyoming residents rely on groundwater as their drinking water source (Powder River Basin Resource Council, 2001). Few public water supply systems exist in the Powder River Basin due to relatively low population densities. The City of Gillette, the largest in the major coalbed methane development area (Figure A5-2), uses groundwater from two sources identified as “in-town wells”, and the “Madison Well Field”. The city has experienced considerable drawdown and reduced production from their in-town wells that are completed in the Fort Union and Lance/Fox Hills aquifers (Brooks, 2001). It is unclear how much of the drawdown is attributable to withdrawals for water supply as a consequence of population growth and how much is attributable to nearby coalbed methane production. Between 1995 and 1998, the city restored and/or replaced several of its wells. The Madison Well Field produces water from the Madison Formation and is approximately 60 miles east of the city. There are no coalbed methane wells in the vicinity of the Madison Well Field (Brooks, 2001).

Regional groundwater flow in the basin is reported to be toward the northwest (Martin et al., 1988 in Law, 1991), with recharge occurring in the east along the Rochelle Hills.

Cleats and other fractures within the coalbeds create high hydraulic conductivities and facilitate the flow of groundwater and high water production within the coalbeds (Montgomery, 1999). The coalbeds are largely hydraulically confined by underlying shale and by basinward pinch-out. Surficial water and rainwater can enter the Fort Union coals from land surface at the eastern edge of the basin and at the Black Hills uplift. This flow inward from outcrop areas at higher elevations on the edge of the basin may have created artesian conditions in the deeper central portions of the basin. However, this view may not be entirely correct. For example, coalbed research (Law et al., 1991) hypothesizes that the sodium bicarbonate water in the Fort Union coal near the central part of the basin may not be derived from meteoric recharge, but rather from interstitial waters of the original peat deposits. Furthermore, Martin et al. (1988, as cited in Law et al., 1991) concluded on the basis of isotopic composition of water samples that only part of the water near outcrops was of meteoric origin. Although artesian pressure in the center of the basin has been thought to be evidence that the center of the basin is fed from meteoric recharge at the basin margins, the apparent artesian pressure (flowing wells) could be explained by the airlift effect of methane coming out of solution within the rising well water column.

Because the coalbeds are productive aquifers, they also require more dewatering of coalbed methane wells for methane production. Groundwater production, in terms of volume of water produced, was a major factor considered in the selection of sites for early coalbed methane wells and may still guide development of sites in some parts of the Powder River Basin. Wells in the eastern portion of the basin have been found to contain less water due to their location above the water table within the eastern anticlinal updip of the formation and, in some areas, due to the presence of nearby mines that dewater the aquifer. Drawdowns of up to 80 feet have been measured in wells near active mines; however, water levels have been reported to be unaffected at distances of more than three miles from mines (Randall, 1991). The Bureau of Land Management in conjunction with the State Engineer's Office has been conducting ongoing research on the effects of coalbed methane production on drawdown (Wyoming Geological Association, 1999).

5.3 Coalbed Methane Production Activity

Coalbed methane activity in Wyoming occurs predominantly in Campbell, Sheridan and Johnson Counties (DeBruin, 2001). Wells are spaced from 40 to 80 acres per well, as determined by the State. Permits are required under both state water well regulations and state gas well regulations before drilling can commence. A discharge permit from the Wyoming Department of Environmental Quality is also required for the water that is removed from the well. Coalbed methane production wells in the Powder River Basin are typically 400 to 1,500 feet deep and can be as shallow as 150 feet (PRCMIC, 2000). By comparison, conventional gas and oil wells installed in the area are typically 4,000 to 12,000 feet deep (PRCMIC, 2000). Plans for construction of approximately 4,000 new coalbed methane production wells in the Montana portion of the Powder River Basin await completion of an in-depth environmental study (DeBruin, 2001).

Commercial development of methane directly from the coal seams began approximately in 1986. There were only 18 wells producing coalbed methane in the Powder River Basin by 1989. The number grew slowly through the early 1990s with 171 wells producing approximately 8 Bcf of gas per year. The rate of development of the resource accelerated greatly from 1997 to 1999. In 1999, there were 1,657 coalbed methane wells operating in the Powder River Basin, producing approximately 58 Bcf per year (Figure A5-9) of coalbed methane. As of November 2000, there were about 4,270 wells in Wyoming producing 15 Bcf of coalbed methane in that month alone (Osborne, 2002). By November 2001, monthly coalbed methane production had climbed to 23.5 Bcf from 7,870 producing wells in Wyoming (Osborne, 2002). In Montana, 246 active wells produced 872,008 Mcf of coalbed methane in December, 2001 (Osborne, 2002). The Powder River Basin has become the most active coalbed methane exploration and production area in the country (DeBruin et al., 2000). Despite all of the activity, less than 5 percent of the land underlain by coal in the Powder River Basin had been explored for the presence of coalbed methane as of the year 2000 (PRCMIC, 2000).

During the early years of coalbed methane development in the Powder River Basin (1980s to early 1990s), gas exploration and development companies completed wells with and without hydraulic fracture techniques. Larsen (1989) indicated that early wells were completed without fracturing treatments, particularly wells targeting gas reserves in coals interspersed between sandstone layers. However, the Quarterly Review (1989) reported that in one well, Rawhide 15-17, located north of Gillette, Wyoming, an “open frac” hydraulic fracturing was performed using 13,000 lbs of 12/20-mesh sand in 3,500 gallons of gelled water. Several wells installed in the early 1990s by Betop, Inc. were fractured using 4,000 to 15,000 gallons of a solution with 2 percent potassium chloride (KCl) in water. Sand was used to prop the fractures open in five of these wells (Quarterly Review, 1993). However, hydraulic fracturing experienced little success in this basin. Fractured wells produced poorly because the permeable, shallow subbituminous coals collapsed under the pressure of the overburden after they were dewatered (Lyman, 2001).

The Powder River Basin contains coals of high permeability. The permeability is so high in many areas that drilling fluid (typically water) is lost when drilling the coalbeds. Many times drilling mud is substituted to prevent loss of circulation (DeBruin, 2001). Because of this high permeability, most coalbed wells in the Fort Union Formation can be drilled and completed without the use of hydraulic fracturing (DeBruin, 2001; Quarterly Review, 1993). This has been confirmed by USGS officials in Wyoming (Brooks, 2001). Hydraulic fracturing is also avoided to prevent fracturing of impermeable formations adjacent to the coal, such as shales, that prevent the migration of groundwater. It is thought that fracturing the shale would increase the amount of water flowing into the wells. When fracturing has been done, it has been with water or sand/water mixtures. Unspecified “modest” improvements in coalbed methane gas flow have been observed (Quarterly Review, 1993).

In the Powder River Basin, two different coalbed methane sources are commonly developed: (1) gas extraction from methane-charged dry sand layers overlying or interbedded with the coals, and (2) conventional methane extraction from the water saturated coal seams. In the eastern (up dip) portion of the basin, the coals in the Wyodak-Anderson seam are relatively shallow and interbedded with sands (Montgomery, 1999) (Figure A5-6). In up dip areas above the water table, wells require minimal dewatering for coalbed methane production because there is little to no water in the sands (Quarterly Review, 1989; Montgomery, 1999). Coal mining operations near Gillette have lowered the water table in the vicinity of the mines, thereby dewatering nearby coalbeds and allowing desorption of methane gas from the coal. The sands are penetrated using open-hole techniques, generally without any fracture treatments (Quarterly Review, 1989). Further west, down dip (Figure A5-6), the coalbed methane producing sands and coals of the Fort Union Formation are separated from the overlying Wasatch Formation by a poorly permeable shale of limited areal extent (Quarterly Review, 1989; Quarterly Review, 1993). Further west, down dip (Figure A5-6) in this more water-saturated part of the basin, coalbed methane wells are also completed as open-hole wells.

The practice of open-hole drilling is commonly used in this region. In this practice, a portion of the borehole in the coal is drilled without any casing or well screen. Most other regions of the country where coalbed methane is recovered use a perforated casing throughout the target coal interval. The open coal zone is then cleaned out with water, and the surrounding coal formation is sometimes fractured to improve recovery of the methane. A submersible pump is set at the bottom of the target zone with tubing to the ground surface to remove groundwater from the well. The methane gas travels up the space between the water tubing and the casing. The well is capped to control the flow of methane gas. Wells are often dewatered for several months before producing optimal quantities of methane gas.

Side jetting has also been performed with some success; however, dynamic open-hole cavitation had not been attempted as of 1993. Side jetting is the process by which water and air are injected at high pressure to enlarge the boring in the coal seam. The cavitation process uses dynamic pressure changes to break apart the coal and to widen the boring within in the coal seam (Quarterly Review, 1993).

Production of coalbed methane from water-saturated coalbeds below the water table first requires partial dewatering of the coal to allow desorption of methane from the coal. Production from water-bearing coal seams can yield significant volumes of water; enough to make it difficult or infeasible to dewater the formation sufficiently to initiate coalbed methane flow (Montgomery, 1999). Tests on 11 wells reported by Crockett (2000) indicate that coalbed methane is desorbed from coal as a consequence of decreased hydrostatic pressure caused by pumping groundwater. One well started desorbing at 92 percent of the original reservoir pressure. “Most drilling to date has attempted to remain near or above the existing water table to minimize water production” (Montgomery, 1999). Modifications to well spacing and pumping configuration have been cited by Montgomery (1999) as showing some promise for allowing greater production from the water-saturated coal seams in the future. Because the water in the deeper coal seams may be original interstitial water, and recharge from meteoric water might not be an important factor (Montgomery, 1999), dewatering of these coals for the purposes of coalbed methane production might become economically feasible.

Disposal of water produced by coalbed methane wells is an issue at many well locations. Coalbed methane wells are generally pumped constantly, removing as much as 168,000 gallons per day of water from deeper formations (Randall, 1991). Averages of 17,000 gallons per day per well are more common (Powder River Basin Resource Council, 2001). Water produced during the dewatering of coalbed wells is generally discharged to stock ponds, water impoundments (reservoirs), drainages with ephemeral and intermittent streams, and surface waters. A National Pollution Discharge Elimination System permit is required for surface discharge of production water. The water is generally of potable quality in the center of the basin, becoming more saline to the north and south. It is sometimes used for irrigation and watering livestock (DeBruin, 2001). TDS levels are typically less than 5,000 parts per million. The water's salt content is primarily sodium bicarbonate (Quarterly Review, 1993). Average analytical results from 47 USGS water quality analyses of untreated, co-produced water from coalbed methane wells in the Powder River Basin are displayed in Table A5-1 below.

Table A5-1. Average Water Quality Results from Produced Waters (Rice et al., 2000)

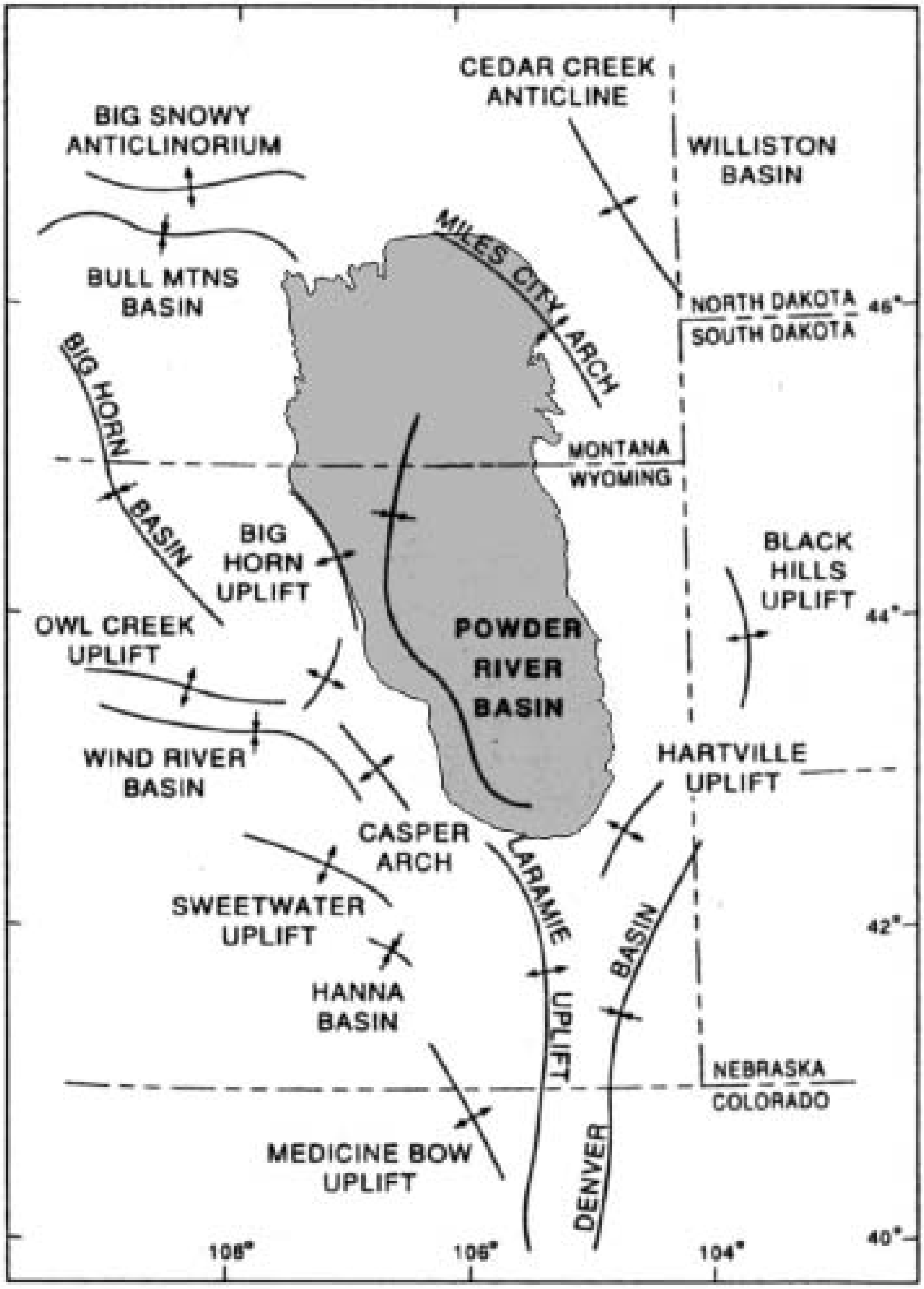
Parameter	Result	Units
pH	7.3	N/A
temperature	19.6	^{o}C
specific conductance	1,300	microsiemens
TDS	850	mg/L
fluoride	0.92	mg/L
chloride	13.0	mg/L
sulfate	2.4	mg/L
bromide	0.12	mg/L
alkalinity (as HCO_3)	950	mg/L
ammonium	2.4	mg/L
calcium	32	mg/L
potassium	8.4	mg/L
magnesium	16	mg/L
sodium	300	mg/L
barium	0.62	mg/L
iron	0.8	mg/L

As a result of the rapid growth in the coalbed methane industry, the Wyoming State Engineer's Office (SEO) requested funding for drilling, equipping, and monitoring of observation wells, and the installation of surface water measuring devices to be located in coalbed methane production areas. These monitoring facilities would become part of the SEO statewide observation well network to monitor changes in groundwater levels and stream flow over time. As of 1999, work was underway, but no report of results had yet been made available.

5.4 Summary

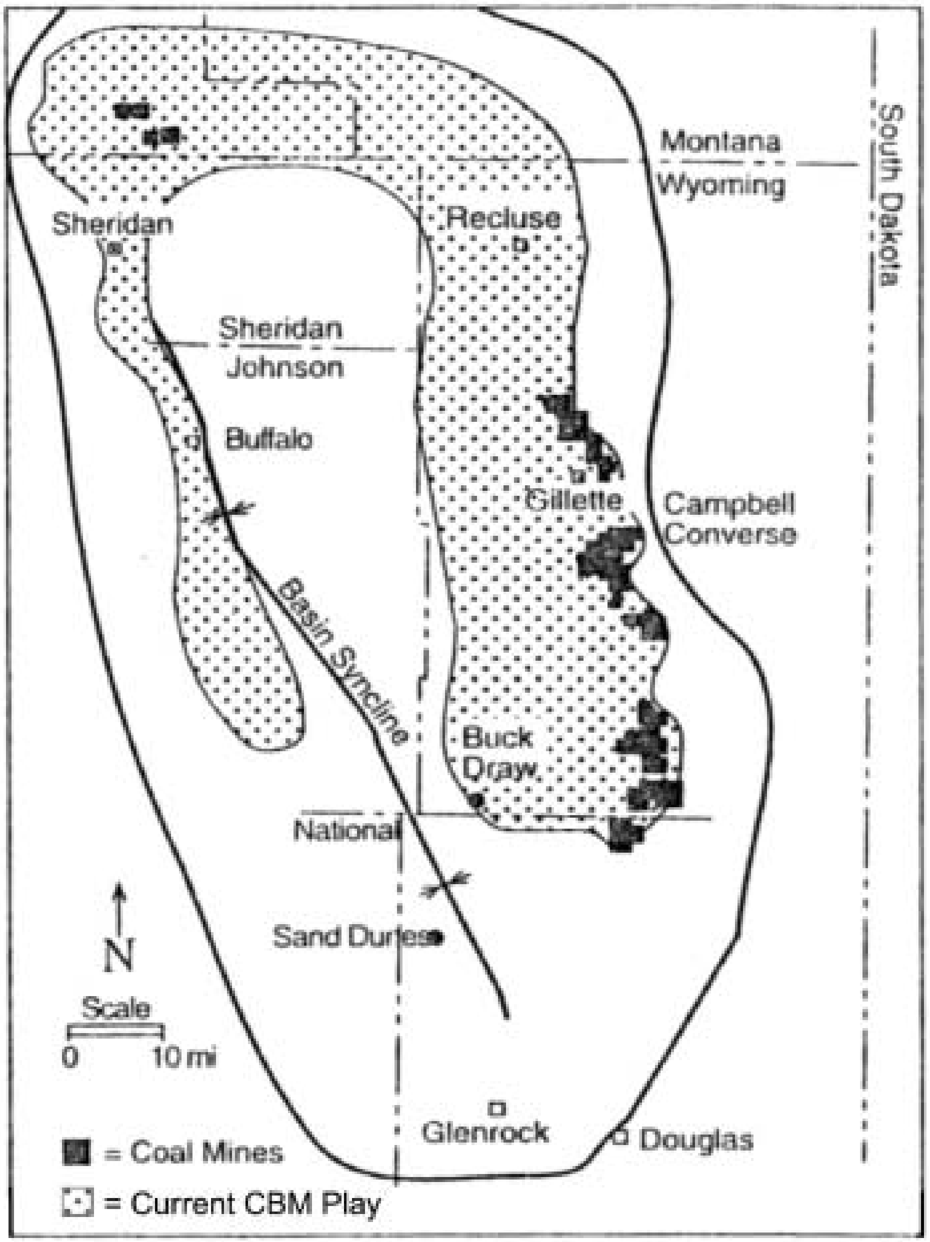
Based on the information for the Powder River Basin, the coalbeds that are being developed, or which may be developed, for coalbed methane in the Powder River Basin are also USDWs. Coalbeds in this basin are interspersed with sandstone and shale at varying depths. The Fort Union Formation that supplies municipal water to the City of Gillette is the same formation that contains the coals that are developed for coalbed methane. The coalbeds contain and transmit more water than the sandstones. The sandstones and coalbeds have been used for both the production of water and the production of coalbed methane. TDS levels in the water produced from coalbeds meet the water quality criteria for USDWs.

The information available indicates that currently hydraulic fracturing is not widely used in this region due to concerns about the potential for increased groundwater flow into the coalbed methane production wells and the consequent collapse of open hole wells in coal upon dewatering. According to the available literature, where hydraulic fracturing has been used in this basin, it has not been an effective method for extracting methane. Hydraulic fracturing has been conducted primarily with water, or gelled water and sand, although the recorded use of a solution of KCl was identified in the literature.



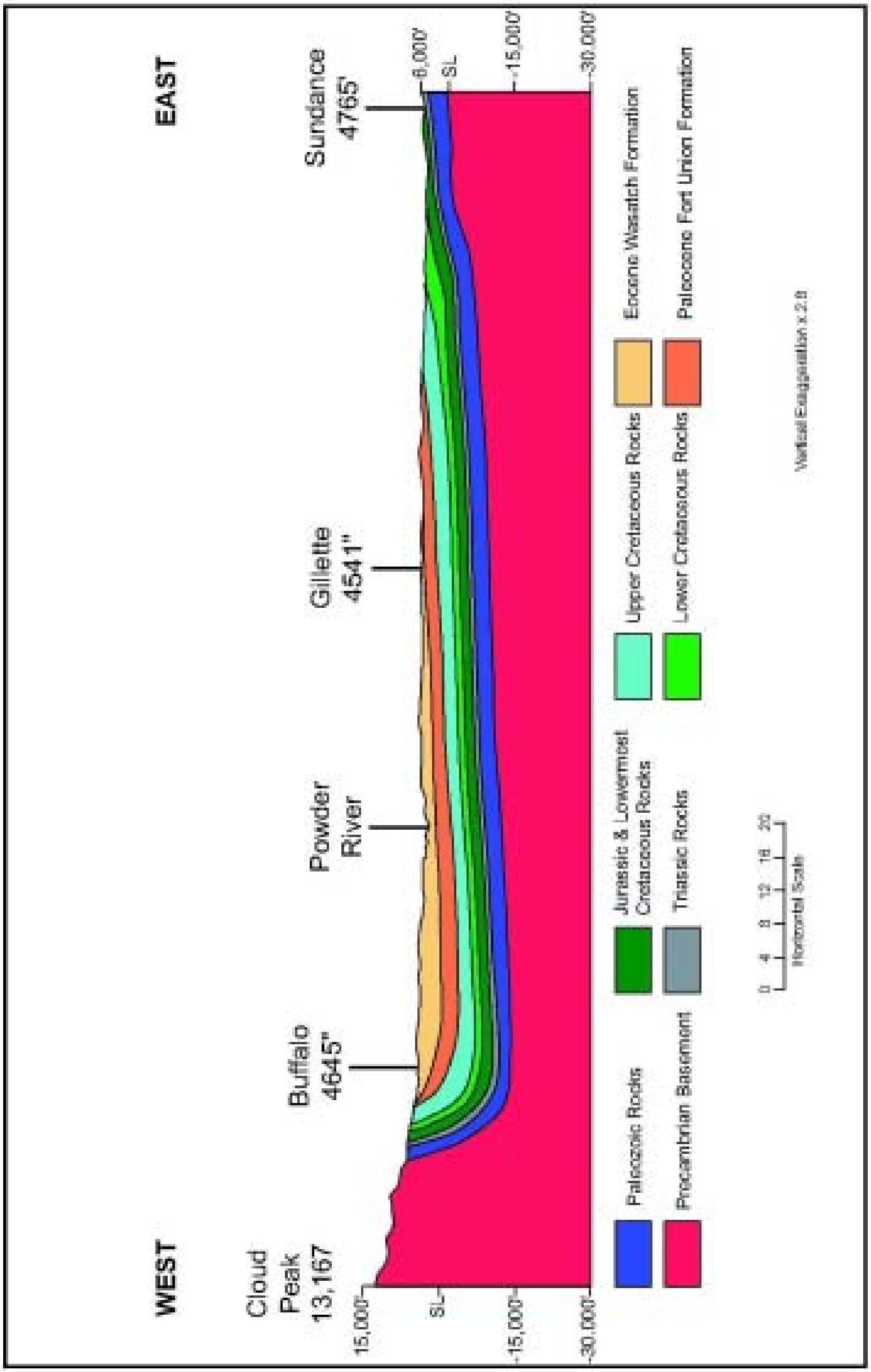
Location of the Powder River Basin of Wyoming and Montana
(Larsen, 1989 and Rice et al, 2000)

Figure A5-1



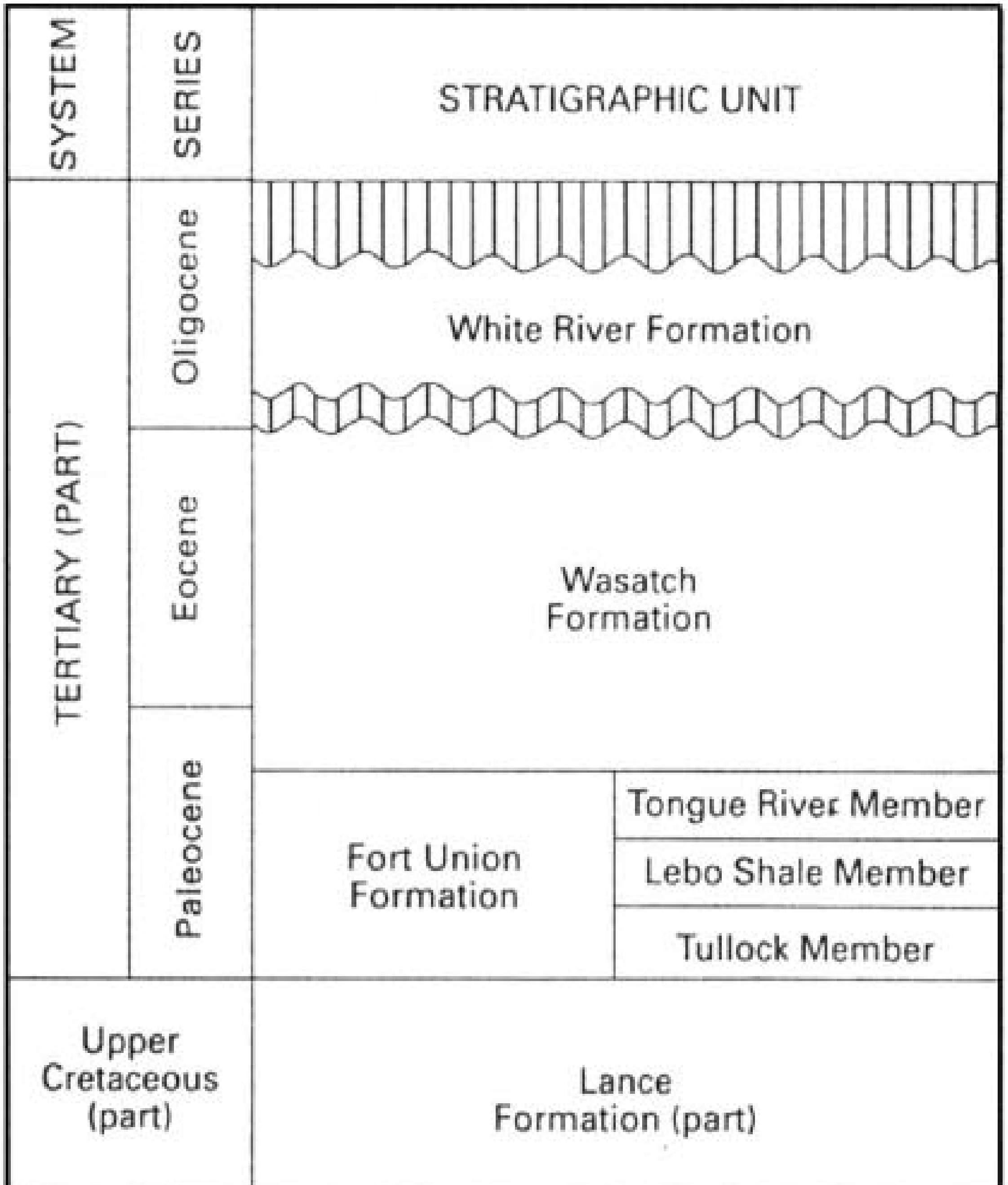
Map of the development of Coalbed Methane in the Powder River Basin
(Montgomery, 1999)

Figure A5-2



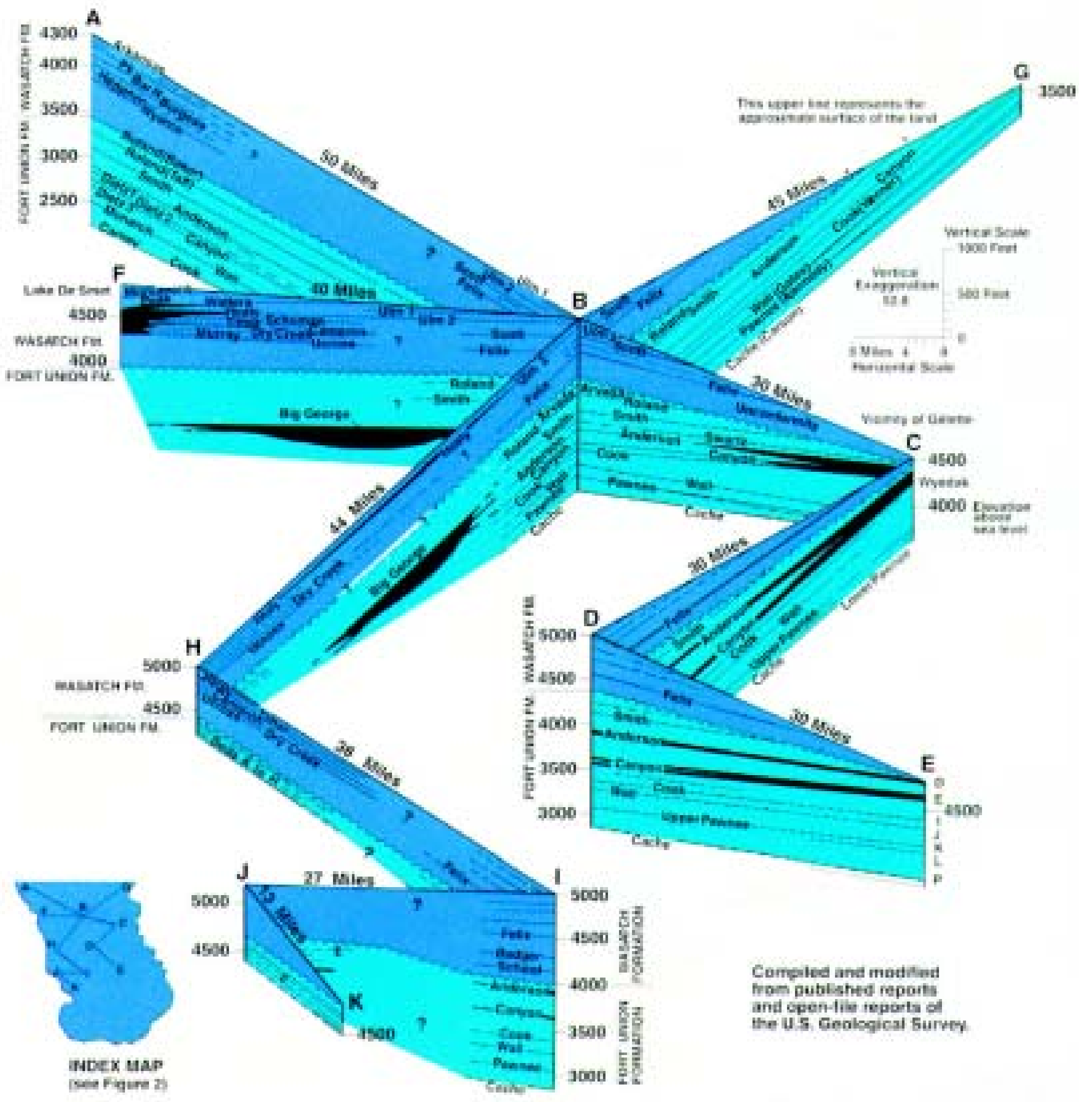
Conceptual Cross Section of the Powder River Basin (West-East) (DeBruin et al., 2000)

Figure A5-3



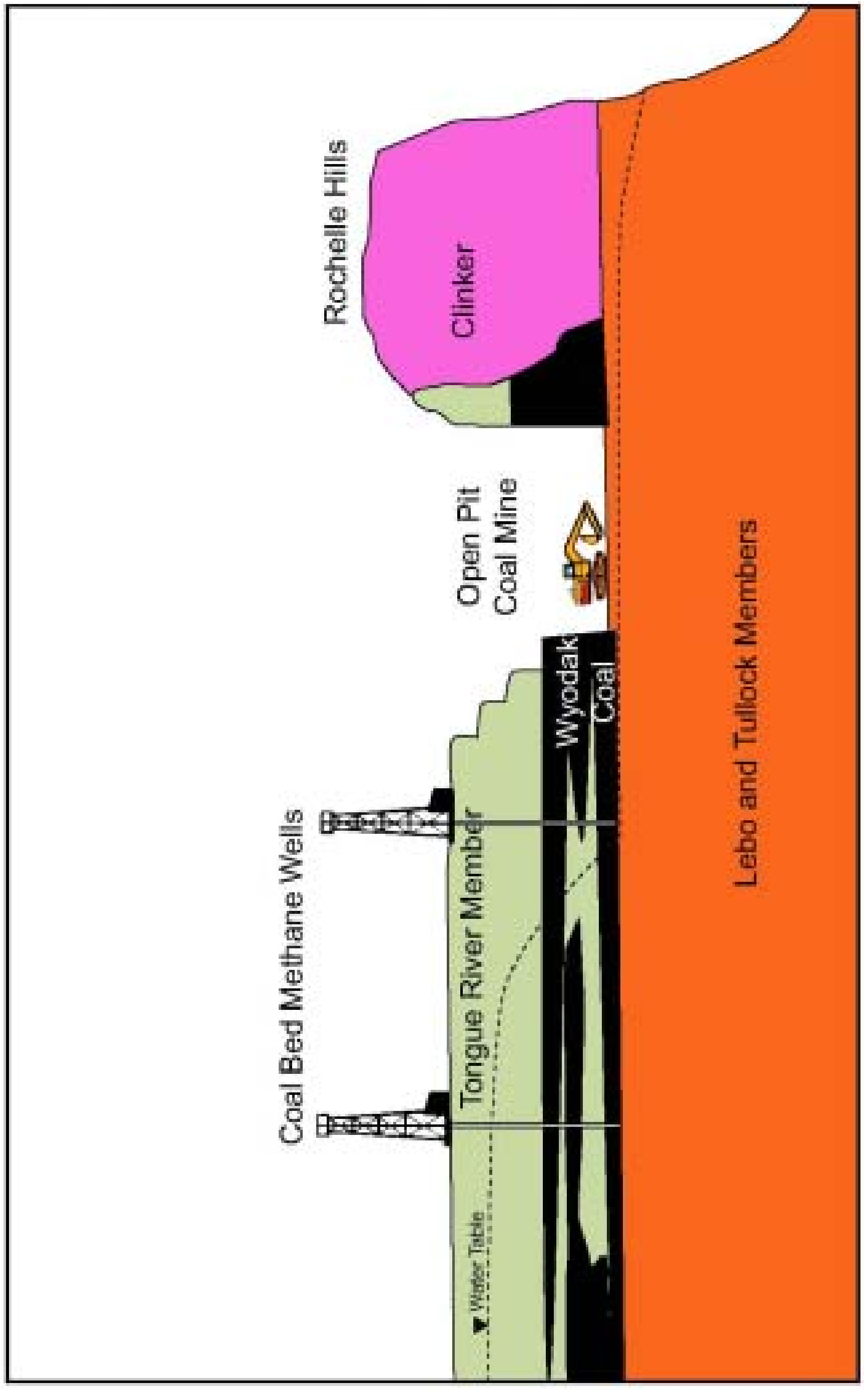
Stratigraphic Diagram of Geology in the Powder River Basin
(Law et al., 1991)

Figure A5-4



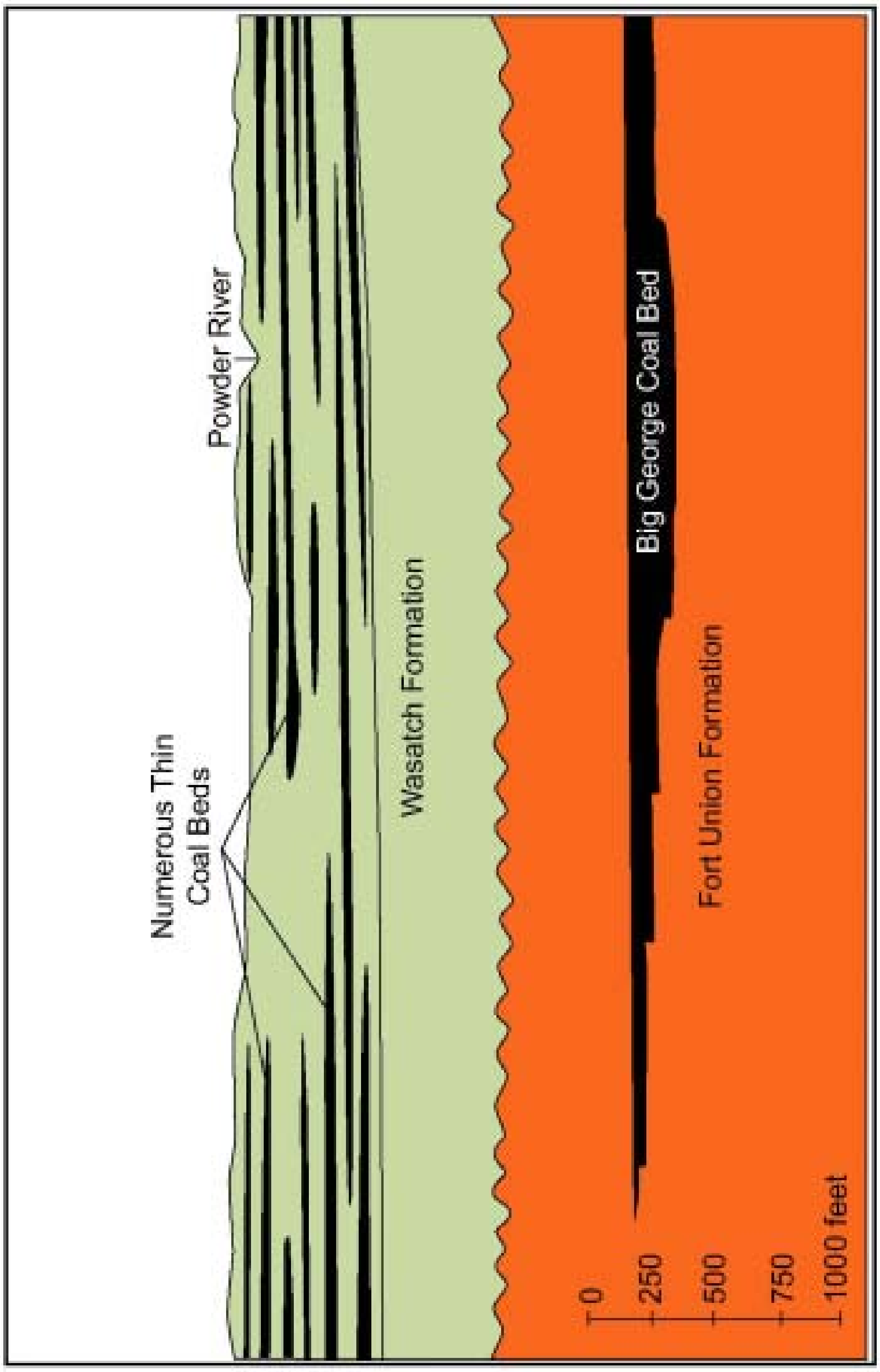
Detailed Cross Section of the Wasatch and Fort Union Formations in the Powder River Basin (DeBruin et al., 2000)

7/14/2001 1027-HF-PR-5 | Figure A5-5



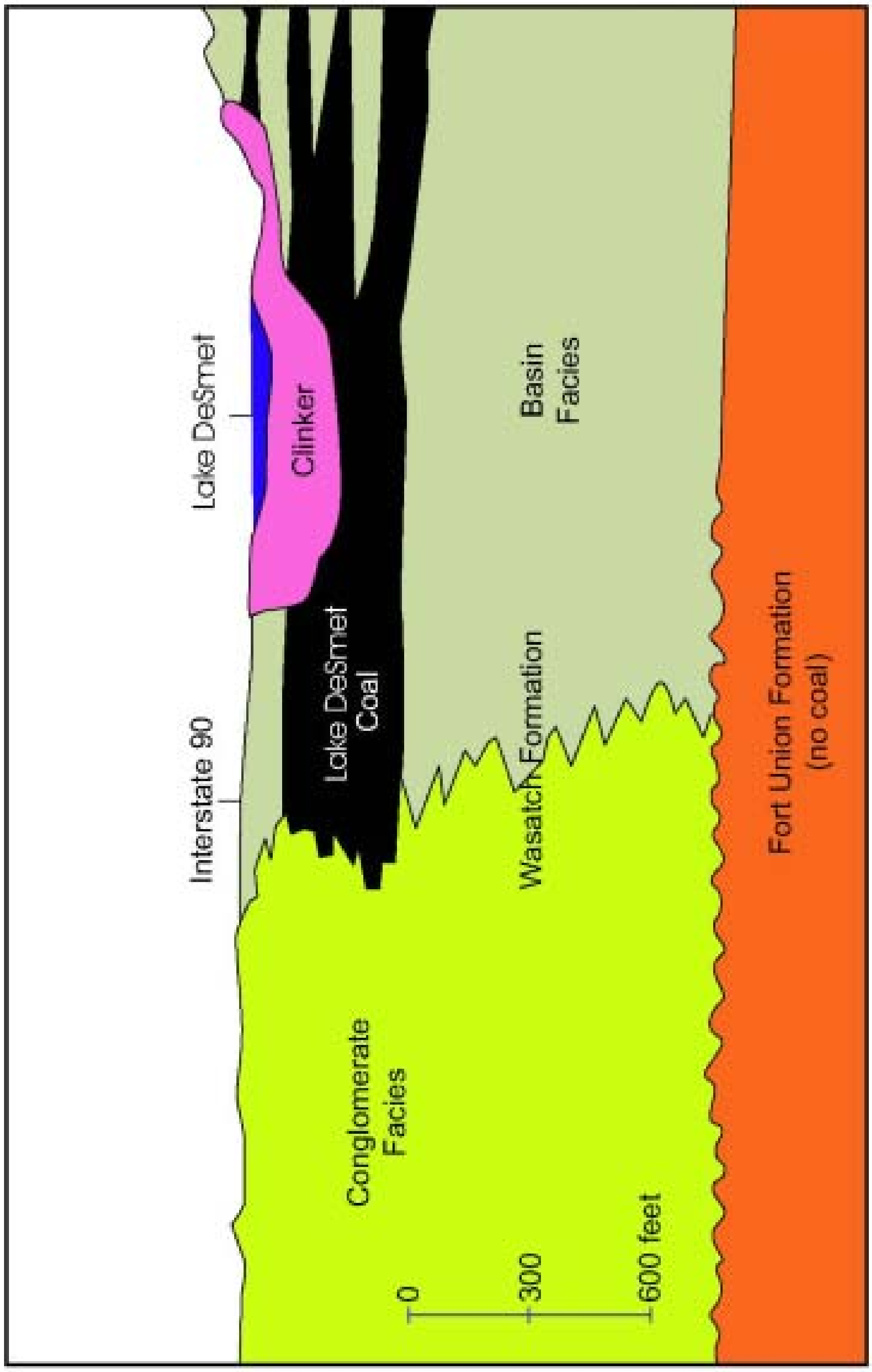
Conceptual Cross Section (West-East) of the Fort Union Formation in the Eastern Powder River Basin
Near Gillette, Wyoming (DeBruin et al., 2000)

Figure A5-6



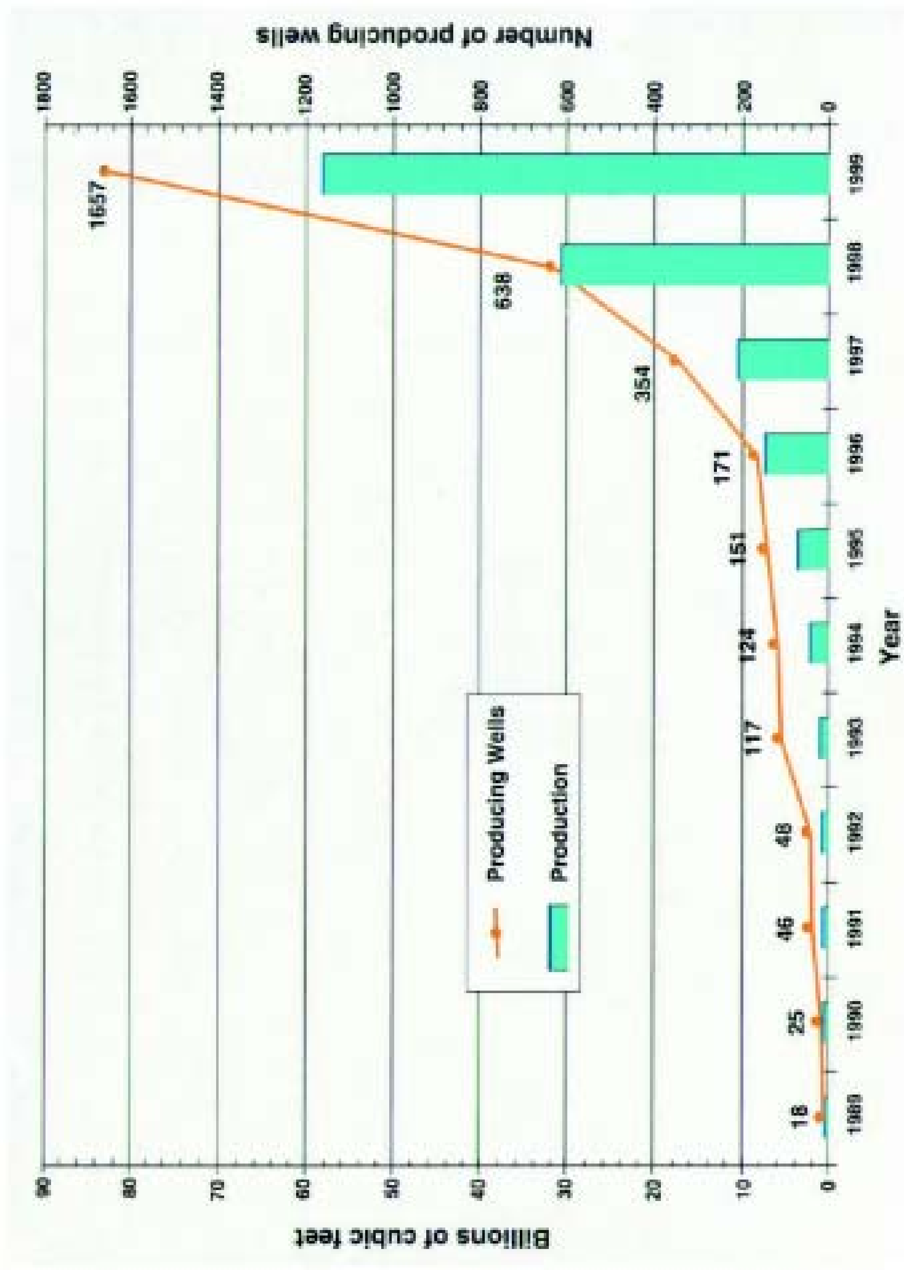
Conceptual Cross Section Near the Center of the Powder River Basin (Debruin et al., 2000)

Figure A5-7



Conceptual Cross Section in the Western Powder River Basin Near Lake DeSmet (DeBruin et al., 2000)

Figure A5-8



Graph of Coalbed Methane Production and Wells in Service in the Powder River Basin, 1989 to 1999 (DeBruin et al., 2000)

Figure A5-9

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Attachment 6
The Central Appalachian Coal Basin

The Central Appalachian Coal Basin is the middle basin of three basins that comprise the Appalachian Coal Region of the eastern United States. It includes parts of Kentucky, Tennessee, Virginia, and West Virginia (Figure A6-1). It covers approximately 23,000 square miles, contains six major Pennsylvanian age coal seams, and contains an estimated 5 trillion cubic feet (Tcf) of coalbed methane (Zebrowitz et al., 1991; Zuber, 1998). These coal seams typically contain multiple coalbeds that are widely distributed (Zuber, 1998). The coals seams, from oldest to youngest (West Virginia/Virginia name), are the Pocahontas No. 3, Pocahontas No. 4, Fire Creek/Lower Horsepen, Beckley/War Creek, Sewell/Lower Seaboard, and Iager/Jawbone (Kelafant et al., 1988). The Pocahontas coal seams include the Squire Jim and Nos. 1 to 7 and Nos. 3 and 4 are the thickest and most areally extensive. The majority of the coalbed methane (2.7 Tcf) occurs in the Pocahontas seams (Kelafant et al., 1988). The highest potential for methane development is in a small, 3,000 square mile area in southwest Virginia and south central West Virginia, where target coal seams achieve their greatest thickness and occur at depths of about 1,000 to 2,000 feet (Kelafant et al., 1988). The Gas Technology Institute (GTI) reported that the entire basin's annual production was 52.9 billion cubic feet (Bcf) of gas in 2000 (GTI, 2002).

6.1 Basin Geology

The Central Appalachian Basin is characterized structurally by broad, open, northeast-southwest trending folds that typically dip less than five degrees (Kelafant et al., 1988) (Figure A6-2). The only documented exception to this is the Pine Mountain Overthrust Block in the southeast portion of the basin (Kelafant et al., 1988). Faults and folds associated with this 25 mile-wide and 125 mile-long structural feature are more intense as evidenced by overturned beds and even brecciated zones in some locations (Kelafant et al., 1988). The overthrust block is believed to have been transported about five miles from the southeast to the northwest (Kelafant et al., 1988). The two dominant joint patterns within the coals are most likely due to the basin having undergone two distinct patterns of structural deformation. These deformations include the Appalachian Orogeny and the tectonic event associated with development of the Pine Mountain overthrust (Kelafant et al., 1988).

The regional dip of coal-bearing Pennsylvanian strata is to the northwest at a rate of 75 feet per mile (Kelafant et al., 1988). Sedimentation within the Central Appalachian Basin was influenced somewhat by the Rome Trough, an Early Cambrian graben structure. Sediment deposition during early Pennsylvanian time (about 320 million years ago) occurred to the southeast of the Rome Trough in a rapidly but intermittently subsiding basin (Kelafant et al., 1988). As this tectonic activity began to abate in the Central Appalachian Basin, subsidence to the northeast of the Rome Trough began to form the Northern Appalachian Basin. However, subsidence rates in the Northern Appalachian Basin were comparatively slower, enabling the formation of more regionally extensive coalbeds (Kelafant et al., 1988).

There are three coal-bearing formations in the Central Appalachian Basin (Kelafant et al., 1988). From deepest to shallowest, they are the Pocahontas Formation, the New River/Lee Formation, and the Kanawha/Norton Formation. Each formation [Pennsylvanian in age (approximately 320 to 290 million years old)] is part of the Pottsville Group, and has varying nomenclature from state to state (Kelafant et al., 1988).

The Pocahontas Formation directly overlies the Mississippian Bluestone Formation, and was deposited in an unstable basin that was rapidly subsiding to the southeast (Kelafant et al., 1988). This is reflected in the thickness of the formation, which is thickest in the southeast and thins to the northwest. It also thins to the south and west due to erosion caused by the basal sandstone member of the overlying New River/Lee Formation (Kelafant et al., 1988). The Pocahontas Formation reaches its maximum thickness of 750 feet near Pocahontas, Virginia (Kelafant et al., 1988). The formation consists mostly of massively bedded, medium-grained subgraywacke, which can be locally conglomeratic (Kelafant, 1988). Gray siltstones and shales are interbedded within the sandstone (subgraywacke) unit, and coal seams comprise about two percent of the total thickness of the Pocahontas Formation (Kelafant et al., 1988).

The New River/Lee Formation conformably overlies the Pocahontas Formation in the northeastern portions of the basin (i.e., there are no time gaps in the depositional record), but there is an unconformity in the east-central portion of the basin (Kelafant et al., 1988). In the southern portion of the basin, the New River/Lee Formation unconformably overlies the Bluestone Formation. It is difficult to correlate this formation across state boundaries as nomenclature varies (Kelafant et al., 1988). The overall thickness of the formation decreases from east to west, with the thickest portion (1,000 feet) in parts of Virginia and West Virginia, lessening to fewer than 100 feet along the Ohio River in Kentucky (Kelafant et al., 1988). Coalbeds encountered in the New River/Lee Formation include the Fire Creek/Lower Horsepen, Beckley/War Creek, Sewell/Lower Seaboard, and the Iager/Jawbone (Kelafant et al., 1988). These coalbeds thin and pinch-out towards the south and west; therefore, there are no equivalent coalbeds in Kentucky and Tennessee (Kelafant et al., 1988).

The Kanawha/Norton Formation varies from a maximum thickness of 2,000 feet in West Virginia to less than 600 feet in portions of Dickenson and Wise Counties, Virginia (Kelafant et al., 1988). The formation is composed of irregular, thin- to massively-bedded subgraywackes interbedded with shale. Several thin carbonate units also occur within the formation as well as over 40 multi-bedded coalbeds.

All coal seams within the basin occur within the Pennsylvanian Pottsville Group (Figure A6-3). Specific stratigraphic nomenclature varies from state to state within the basin. (Names used in this summary are consistent with the West Virginia/Virginia nomenclature).

The Pocahontas No. 3 coal seam ranges in depth from outcrop along the northeastern edge of the basin to about 2,500 feet, with a thickness ranging up to seven feet (Kelafant et al., 1988). Depths to the Pocahontas No. 4 coal seam are somewhat similar to those for the Pocahontas No. 3 coal seam, as the No. 4 seam overlies the No. 3 seam by roughly 30 to 100 feet. The thickness of the No. 3 coal seam varies, with a maximum of approximately seven feet (Kelafant et al., 1988). The Fire Creek/Lower Horsepen coalbed ranges in depth from roughly 500 feet over half of its area, to a maximum depth of approximately 1,500 feet, with a maximum thickness of roughly six feet (Kelafant et al., 1988). The Beckley/War Creek coalbed is approximately two to five feet thick, and reaches to a maximum depth of about 2,000 feet (Kelafant et al., 1988). The Sewell/Lower Seaboard coalbed is fairly shallow, less than 500 feet in depth over half the area it covers, reaching to a depth over 1,000 feet in one small area. While this coal ranges in thickness from two to six feet, it averages about two feet in West Virginia and one foot in Virginia (Kelafant et al., 1988). The youngest targeted coal seam, the Iaeger/Jawbone, is generally less than 500 feet in depth, reaching its maximum depth of over 1,000 feet in two Virginia Counties. The thickness of the Iaeger/Jawbone coal ranges from two to six feet (Kelafant et al., 1988). Figures A6-4 through A6-9 are isopach maps for the six major coal groups of the Appalachian Coal Basin (adapted from Kelafant, et al., 1988).

6.2 Basin Hydrology and USDW Identification

The primary aquifer in the Kentucky portion of the Central Appalachian Basin is a Pennsylvanian sandstone aquifer underlain by limestone aquifers (National Water Summary, 1984). Water wells are typically 75 to 100 feet deep in the Pennsylvanian aquifer and commonly produce one to five gallons per minute of water (National Water Summary, 1984). The basin is located in a portion of the Cumberland Plateau physiographic province in Tennessee (National Water Summary, 1984). The primary aquifer in this area is a Pennsylvanian sandstone aquifer, comprising water-bearing sandstone and conglomerate subunits with interbedded shale and coal (National Water Summary, 1984). Water wells are typically 100 to 200 feet deep and usually produce 5 to 50 gallons per minute of water (National Water Summary, 1984). In Virginia, the basin is located in a portion of the Appalachian Plateau physiographic province. The primary aquifer in this region is the Appalachian Plateau Aquifer, a consolidated sedimentary aquifer consisting of sandstone, shale, siltstone, and coal (National Water Summary, 1984). Water wells are typically 50 to 200 feet deep, and commonly produce one to 50 gallons per minute of water (National Water Summary, 1984). In West Virginia, the basin is in a portion of the Appalachian Plateaus physiographic province of that state. The primary aquifers in this area are Lower Pennsylvanian aquifers, which include the Pottsville Group (National Water Summary, 1984). Wells are commonly 50 to 300 feet deep and typically produce one to 100 gallons per minute of water (National Water Summary, 1984).

Produced water volumes from coal seams within the Central Appalachian Basin are relatively small, typically only several barrels or less per day per well, with high total dissolved solid (TDS) levels, usually greater than 30,000 milligrams per liter (mg/L) (Quarterly Review, 1993). Half the states (Kentucky and Ohio) within the Central Appalachian Basin have maps to locate the undulating interface between saline and freshwater aquifers. The remaining states (Tennessee and Virginia) have no maps defining this interface. Mike Burton (2001), a geologist with the Oil and Gas Office of the Tennessee Geology Division (TGD), reports that the state has no data relating to coalbed methane, which suggests that little or no coalbed methane extraction occurs inside Tennessee's borders (Burton, 2001). Luke Ewing (Ewing, 2001) of the TGD reported that the state had no aquifer maps. Scotty Sorles (Sorles, 2001) of Tennessee's Underground Injection Control Program mentioned that within the state, produced water disposal methods vary on a site-by-site basis. Depending on site characteristics, all injected waters must either be returned to the formation from which they came, or be treated to drinking water levels prior to injection elsewhere (Sorles, 2001).

Robert Wilson, Director of the Virginia's Division of Gas & Oil, stated that there is no mapping program for underground sources of drinking water (USDWs) or for the fresh/saline groundwater interface in Virginia. He reported that the most potable water is found far above the coal zones used for coalbed methane extraction, with fresh water typically found at less than 300 feet deep. He believes most drinking water in southwestern Virginia comes from wells in fractured bedrock aquifers or shallow coal aquifers, or, in some areas, directly from springs. Mr. Wilson also stated that some coalbed methane exploration has moved to shallower coal seams. The Commonwealth of Virginia has instituted a voluntary program concerning depths at which hydraulic fracturing may be performed (Virginia Division of Oil and Gas, 2002). This program involves an operator's determination of the elevations of the lowest topographic point and the deepest water well within a 1,500-foot radius of any proposed extraction well (Wilson, 2001). Hydraulic fracturing should occur at least 500 feet deeper than the lower of these two points (Wilson, 2001).

According to Mr. Tony Scales of the Virginia Department of Mines, Minerals and Energy, coal seams are the most permeable layers in the geologic subsurface in Virginia. For this reason, many private wells in the coalbed methane-producing counties are finished within the coalbeds. Mr. Scales stated that impacts to water supplies have occurred if the coal seams have been punctured by coalbed methane well drilling. The puncture hole acts as a conduit for the flow of water out of the coals and into lower formations. The puncture hole also allows methane to rise up to the surface (Virginia Department of Mines, Minerals, and Energy, 2002).

The following table contains information concerning the relative locations of the base of the zone of fresh water and potential methane-bearing coalbeds in the Central Appalachian Coal Basin. The table provides useful information that can help in determining whether coalbeds being used or slated for methane development lie within USDWs. Note that the 10,000 mg/L level of TDS in groundwater is the water quality criterion for a USDW. The depth to the USDW will thus lie well below the fresh water/ saline water interface. The area of focus for coalbed methane exploration in the basin only covers parts of Virginia and West Virginia (Figure A6-1). In Virginia, the depth to the base of fresh water is approximately 300 feet, whereas the depths to the bases of USDWs are greater. Thus, as can be seen in Table A6-1, methane-producing coalbeds could lie within USDWs in Virginia. West Virginia's interface between fresh and saline water (Foster, 1980) is based on a qualitative assessment, and is estimated at 280 to 730 feet. Again, the depths to USDWs are greater, and thus the coalbeds of interest could lie within potential USDWs in West Virginia. Finally, in Kentucky the interface between fresh water and saline water is based on a TDS level of 1,000 mg/L (Hopkins, 1966). Although the depths to methane-producing coalbeds in Kentucky are not listed in the Table A6-1, it is possible that, as in Virginia and West Virginia, such depths could be lower than the base of USDWs in Kentucky.

Table A6-1. Relative Locations of USDWs and Methane-Bearing Coalbeds

<table>
<tr><th>Central Appalachian Coal Basin, States and Coal Groups</th><th colspan="2">Tennessee</th><th colspan="2">Virginia</th><th colspan="2">West Virginia</th><th colspan="2">Kentucky</th></tr>
<tr><th></th><th>Depth to top of Coal (ft)</th><th>Depth to Base of Fresh Water[1] (ft)</th><th>Depth to top of Coal[2] (ft)</th><th>Depth to Base[1] of Fresh Water[3] (ft)</th><th>Depth to top of Coal[2] (ft)</th><th>Depth to Base[4] of Fresh Water[1] (ft)</th><th>Depth to top of Coal[2] (ft)</th><th>Depth to Base[5] of Fresh Water[1] (ft)</th></tr>
<tr><td>Iaeger/Jawbone</td><td>N/A[6]</td><td rowspan="6">N/A</td><td>0 to 1000</td><td rowspan="6">~ 300</td><td>0 to < 1000</td><td rowspan="6">~ 280 to 730</td><td>N/A[6]</td><td rowspan="6">~ 700 to 1000</td></tr>
<tr><td>Sewell/Lower Seaboard</td><td>N/A</td><td>500 to 1000</td><td>0 to < 1000</td><td>N/A</td></tr>
<tr><td>Beckley/War Creek</td><td>N/A</td><td>500 to 2000</td><td>< 500 to 1000</td><td>N/A</td></tr>
<tr><td>Fire Creek/Lower Horsepen</td><td>N/A</td><td>500 to 1500</td><td>< 500 to 1000</td><td>N/A</td></tr>
<tr><td>Pocahontas No. 4</td><td>N/A</td><td>500 to 2000</td><td>< 500 to < 2000</td><td>N/A</td></tr>
<tr><td>Pocahontas No. 3</td><td>N/A</td><td>500 to 2000</td><td>< 500 to < 2500</td><td>N/A</td></tr>
</table>

[1] Note: The base of "fresh water" is not the base of the USDW (a 10,000 mg/L of TDS contour line would define the base of the USDW). Fresh water is within the USDW and the base of fresh water is above the base of the USDW.
[2] Kelafant et al., 1988
[3] Wilson, DGO, personal communication 2001
[4] Foster, 1980
[5] Hopkins, 1966 and USGS, 1973
[6] Not Available

6.3 Coalbed Methane Production Activity

Coalbed methane operators in the Central Appalachian Basin include Equitable Resources, CONSOL (Consolidation Coal Company), and Pocahontas Gas Partnership, all located in Virginia (Zuber, 1998). GTI reported that the entire basin's annual production was 52.9 Bcf of gas in 2000 (GTI, 2002).

The Nora Field in southwestern Virginia is one of the better known coalbed methane production fields. Equitable Resources operates the Nora Field in southwestern Virginia. According to the

Virginia Division of Gas and Oil, over 700 coalbed methane wells were drilled in the Nora Field in 2002 and more than 1,800 coalbed methane wells were drilled in southwestern Virginia's Buchanan County (VA Division of Gas and Oil, 2002). Foam or water is used as the fracturing fluid and about 70,000 to 100,000 pounds of sand per well serve as proppant (Zuber, 1998). CONSOL and Pocahontas Gas Partnership produce coal methane from coal mine developments in Buchanan County, in southwestern Virginia (Zuber, 1998).

Many other smaller test projects were carried out in the basin in the 1970s, including the New River Coal Company/Lick Run Mine Project, Department of Energy (DOE)/Clinchfield Coal Company Project, U.S. Bureau of Mines (USBM)/Occidental Research/Island Creek Coal Company Project, Gas Research Institute/Wyoming County Co-op Project, USBM Federal No. 1 Project, and the Consolidation Coal Company/ Kepler Mine Project (Hunt and Steele, 1991). These projects were very small (five wells or fewer) and achieved limited success in terms of production. During development of some wells in the DOE/Clinchfield Coal Company project and the USBM Federal Project No. 1, fracture treatments "screened out" (i.e., the proppant placement failed), affecting those coalbed methane wells' production viability.

No coalbed methane production occurred in Tennessee between 1995 and 1997 (Lyons, 1997). Three coalbed methane wells produced gas from 1957 to 1980 in Harlan County, Kentucky, and only one test well was in production in the early 1990s in eastern Kentucky (Lyons, 1997). The Kentucky Department of Mines and Minerals website (2002) indicated that 1,338 gas wells were in operation in Kentucky at the end of 2000, but no indication was given whether these were coalbed methane wells or conventional gas wells.

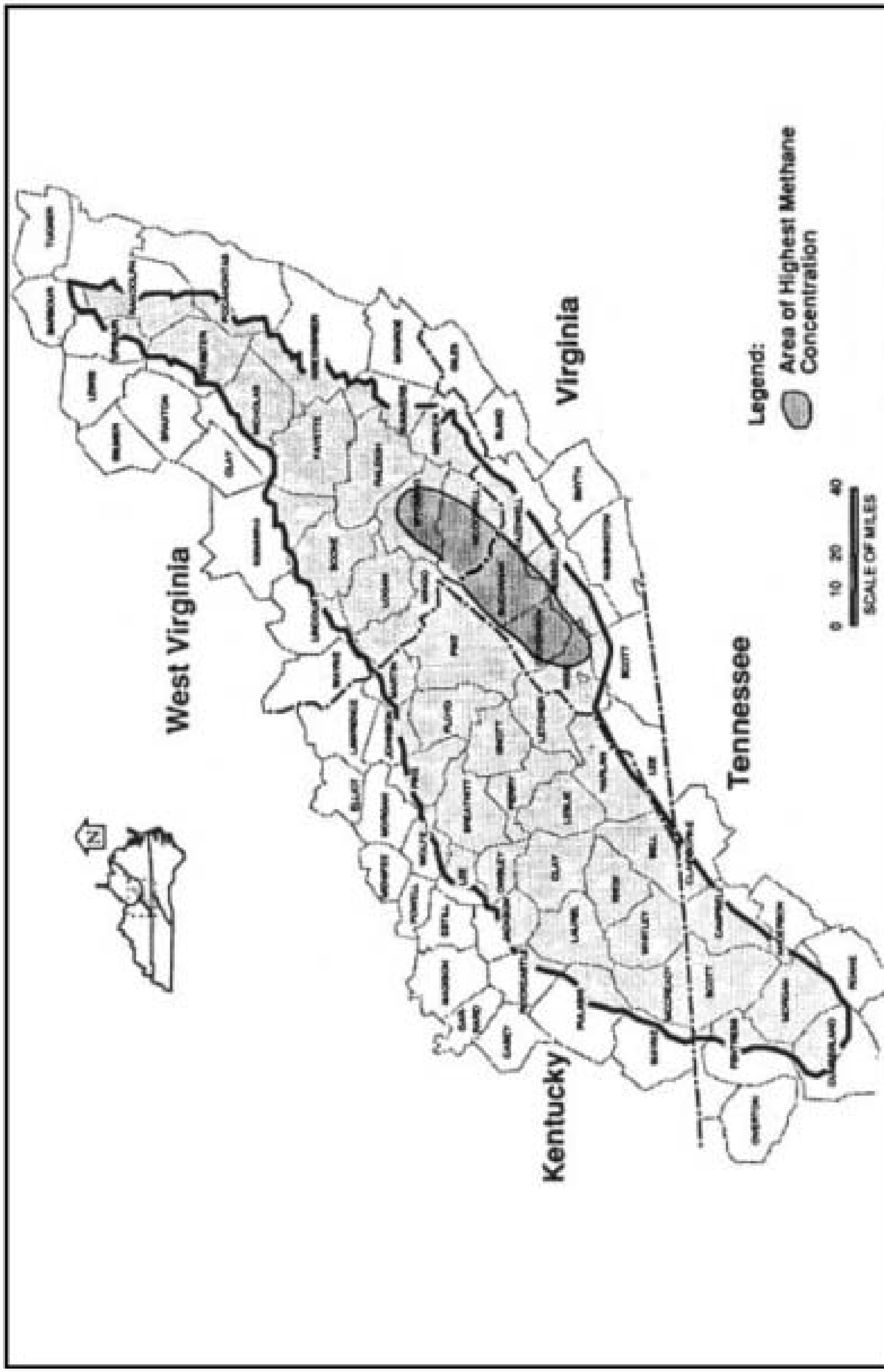
In August 2001, EPA attended a hydraulic fracturing field visit in the Central Appalachian coal basin in Virginia. Pocahontas Oil & Gas, a subsidiary of Consol Energy, Inc., invited EPA personnel to a well location where a hydraulic fracturing treatment was being performed by Halliburton Energy Services, Inc. This treatment employed a variety of fluids and additives to create fractures in select coal seams at various depths. The main fracturing fluid was nitrogen foam (70% nitrogen / 30% water mixture). Prior to injection of the foam, 6 barrels of 15 percent hydrochloric acid were introduced into the well to dissolve the grout surrounding the injection perforations. Once the fracture was propagated to its maximum extent, 16/30 sand suspended in a 10-pound linear gel was injected to prop the fracture open. All the fluids and additives used were produced by Halliburton, including a scale inhibitor and a microbicide additive. Halliburton staff stated that typical fractures range in length from 300 to 600 feet from the well bore in either direction, but that fractures have been known to extend from as few as 150 feet to as many as 1,500 feet in length. According to the fracturing engineer on-site, fracture widths range from one eighth of an inch to almost one and a half inches (Virginia Site Visit, 2001).

Once a well is drilled and fractured in Virginia, several weeks might elapse before fracturing fluid flowback is initiated because a pipeline system must be constructed to transport the produced coalbed methane away from the well. Flowback fracturing fluids are collected in lined pits and tanks and transported off-site for disposal. The State of Virginia does not regulate the use of any drilling or fracturing fluids (Wilson, 2001).

6.4 Summary

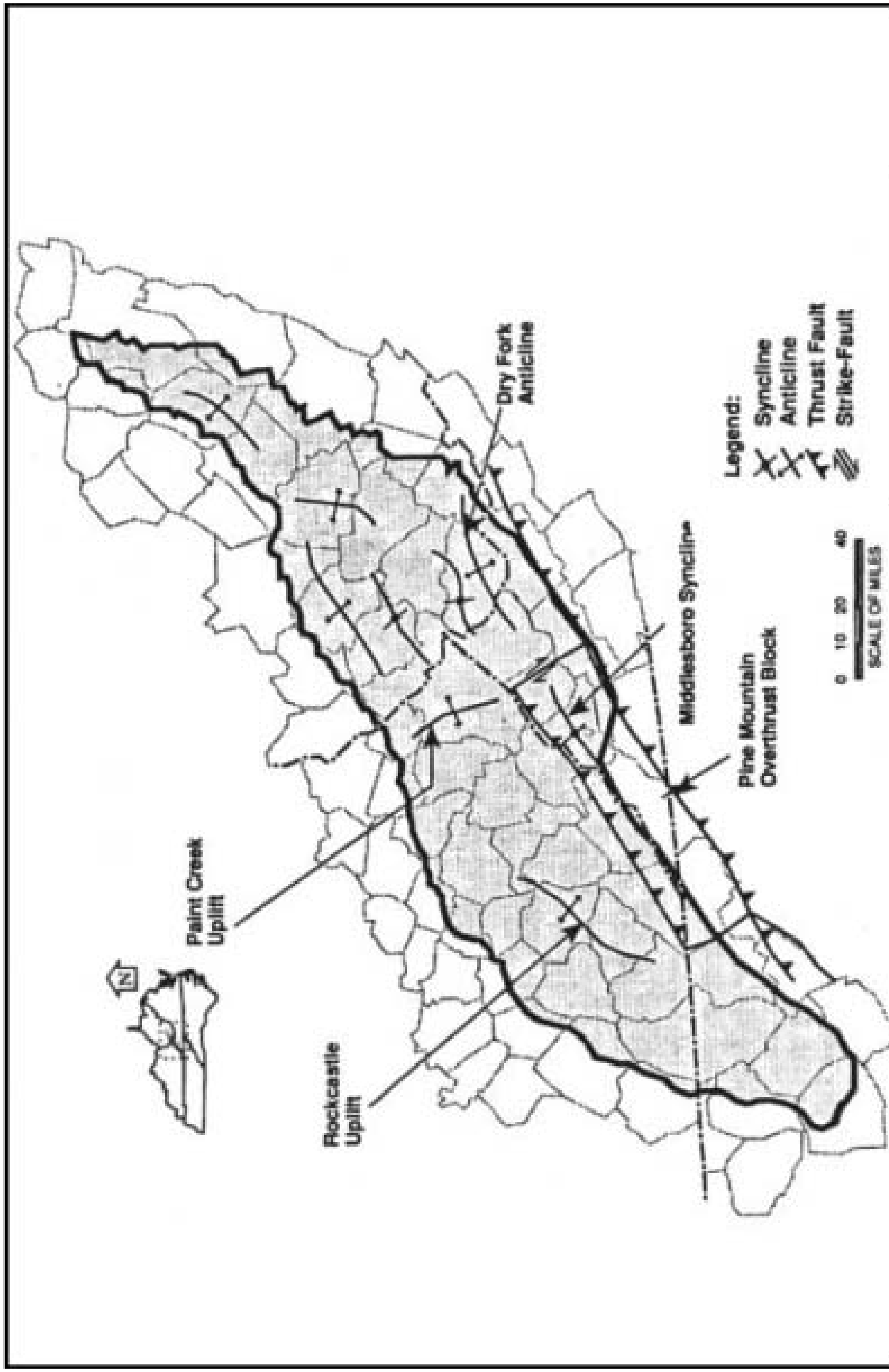
The area with the highest potential for coalbed methane production in the Central Appalachian Coal Basin is southwestern Virginia (Dickenson and Buchanan Counties) and southern West Virginia (Wyoming and McDowell Counties) (Figure A6-1). The coal seams achieve their greatest thickness in these regions and occur at depths of approximately 1,000 to 2,000 feet. Based on Table A6-1, methane-producing coal may lie within a USDW, providing the potential for impact of water supplies.

Hydraulic fracturing is common practice in this region. Foam and water are the fracturing fluids of choice and sand serves as the proppant. Because most of the coal strata dip, a coalbed methane well's location within the basin may determine if hydraulic fracturing during the well's development will likely affect water quality within the surrounding USDW. For instance, on the northeastern side of the basin, the depth to the Pocahontas No. 3 coalbed is less than 500 feet. This depth increases to over 2,000 feet in the western portion of the basin, in the direction of the coal seam dip. Therefore, a well tapping this coal seam in the western portion of the basin may be below the base of a USDW but a well tapping this coal seam in the eastern portion of the basin may be within a USDW. Additionally, the base of the freshwater is not a flat surface, but rather an undulating one. These factors indicate that the relationship between a coalbed and a USDW must be determined on a site-specific basis.



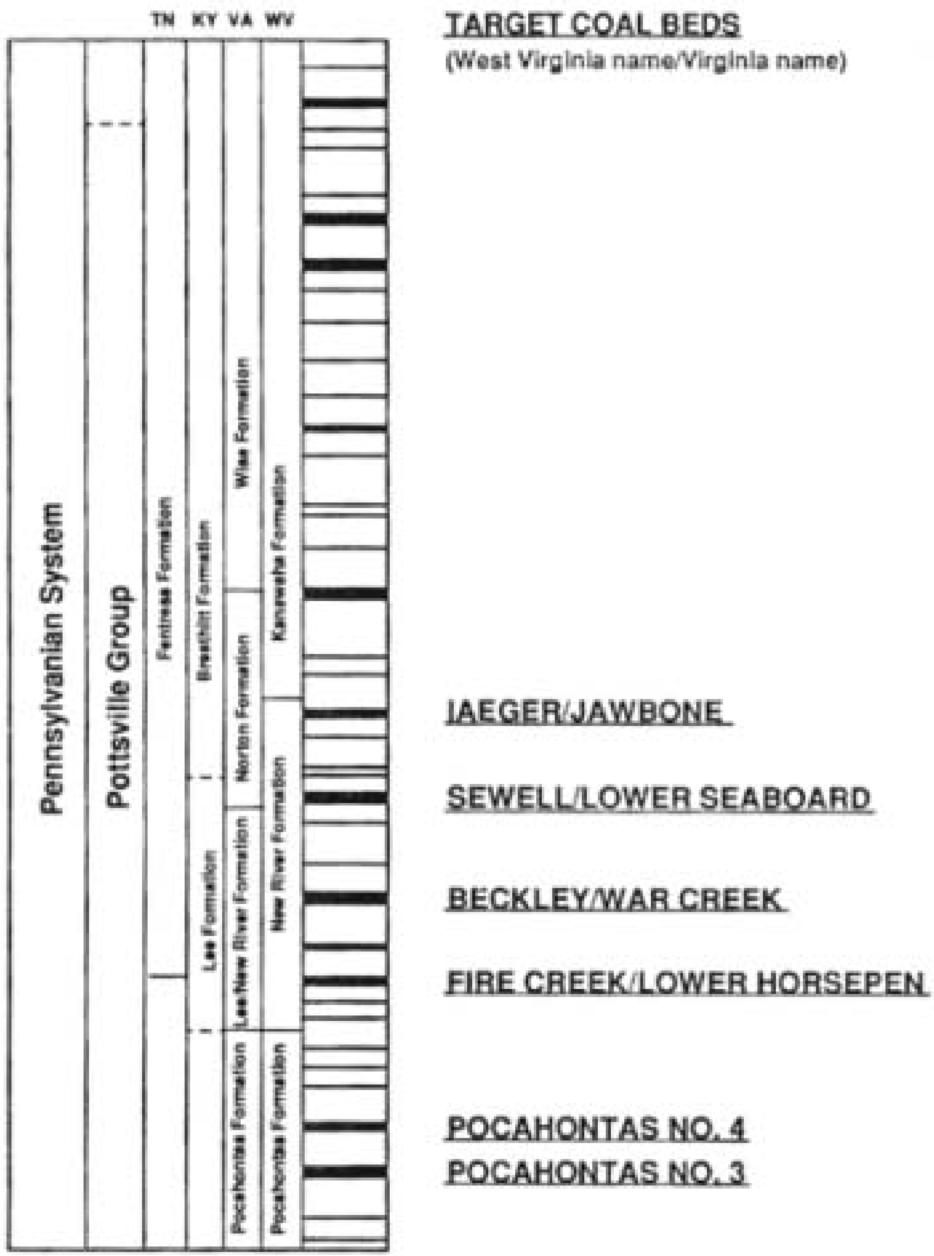
Area of Highest Methane Concentration (Kelafant et al., 1988)

Figure A6-1



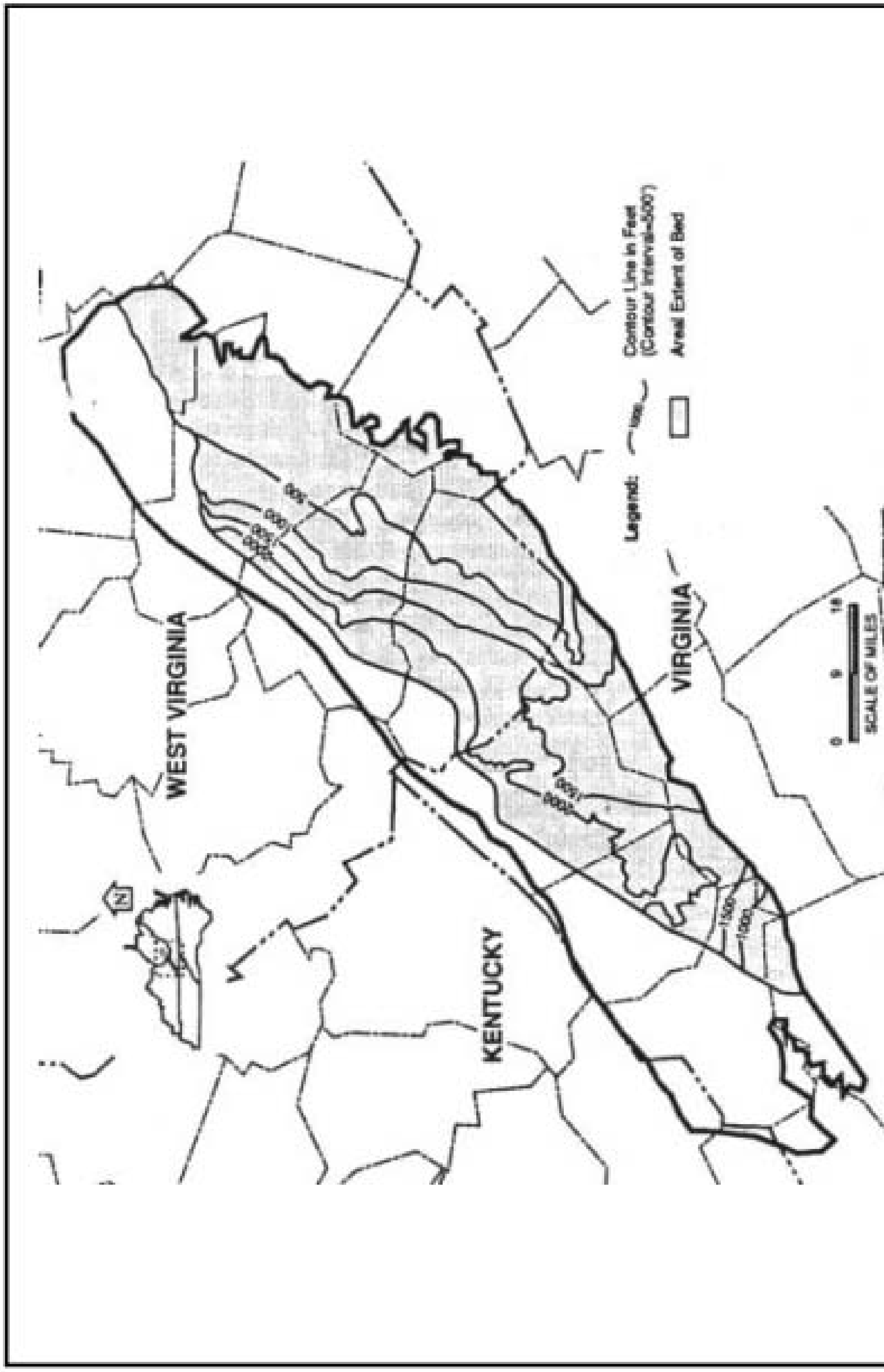
Structural Features (Kelafant et al., 1988)

Figure A6-2



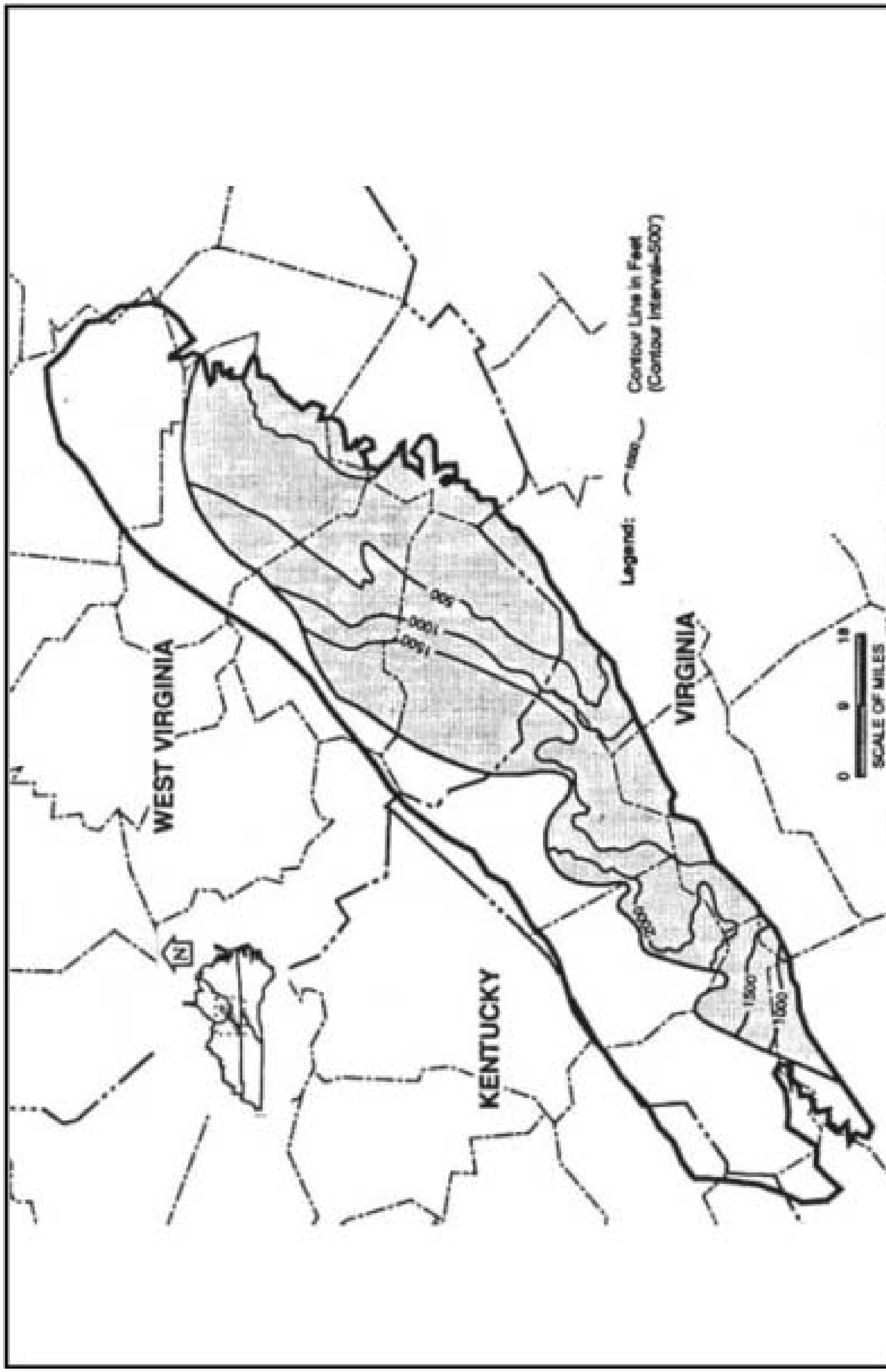
Representative Stratigraphic Column of Pennsylvanian Age Formations
(Kelafant et al., 1988)

Figure A6-3



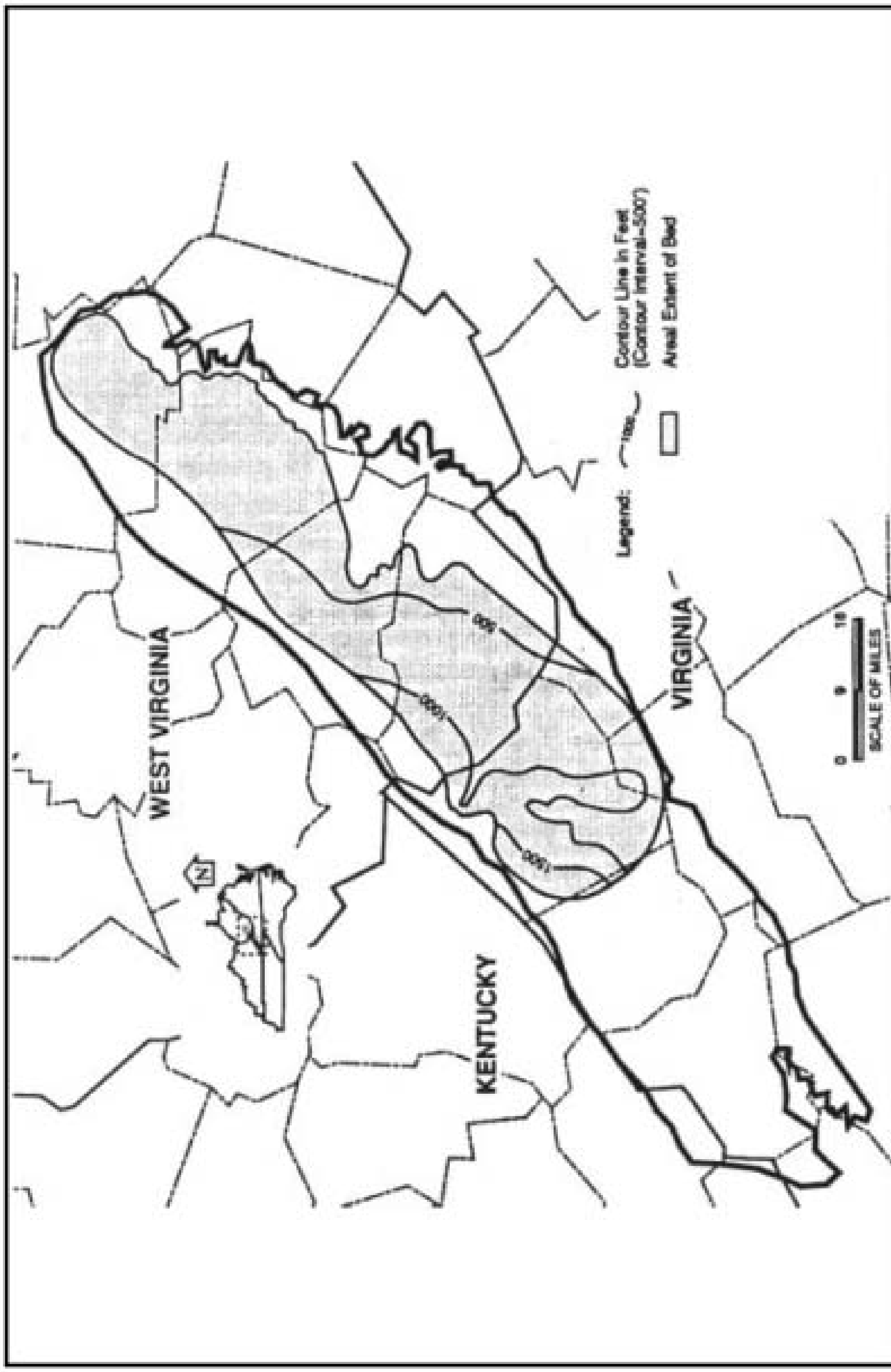
Isopach Map: Thickness of Cover Over the Pocahontas No. 3 Coalbed (Kelafant et al., 1988)

Figure A6-4



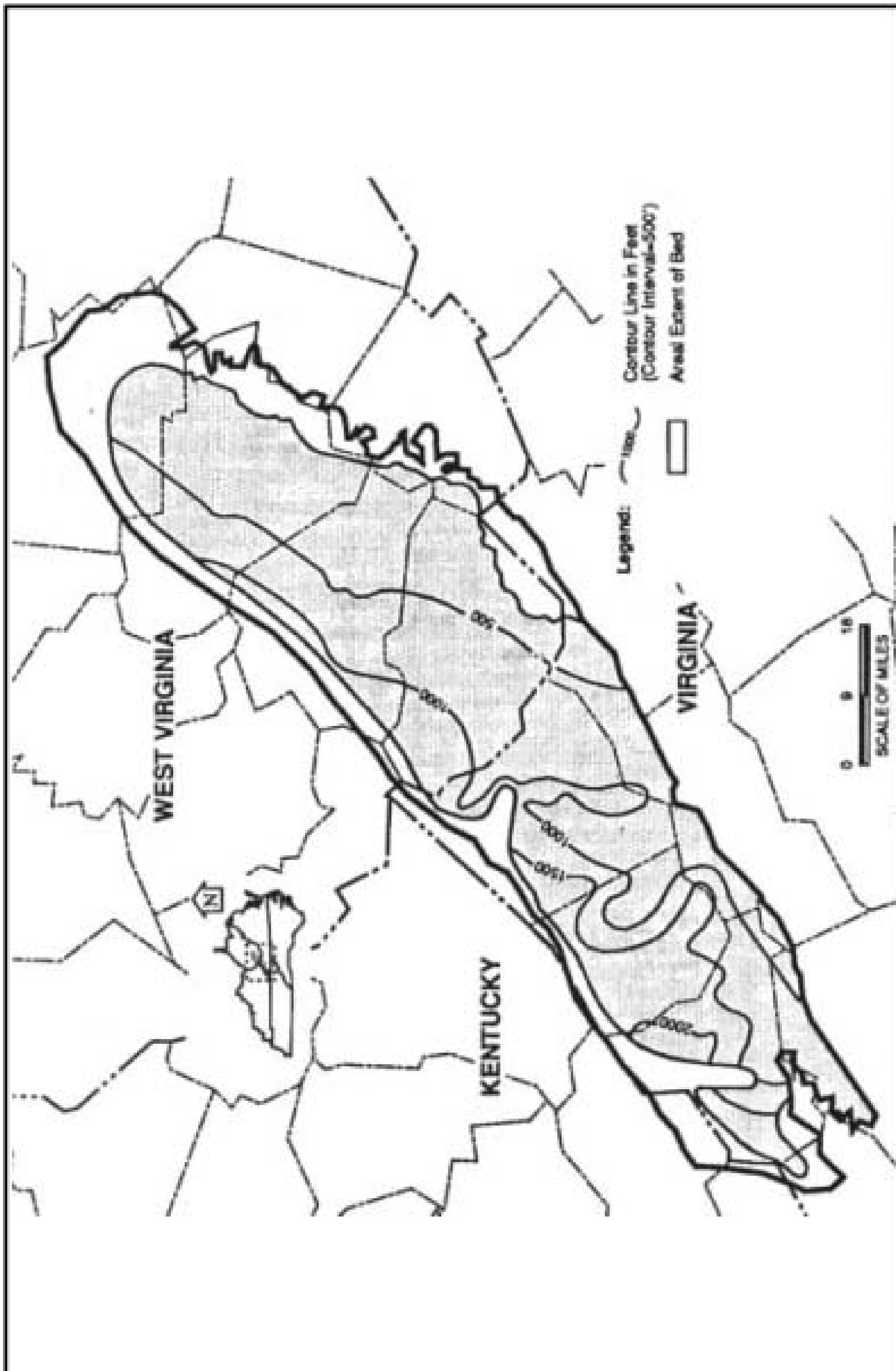
Isopach Map: Thickness of Cover Over the Pocahontas No. 4 Coalbed (Kelafant et al., 1988)

Figure A6-5



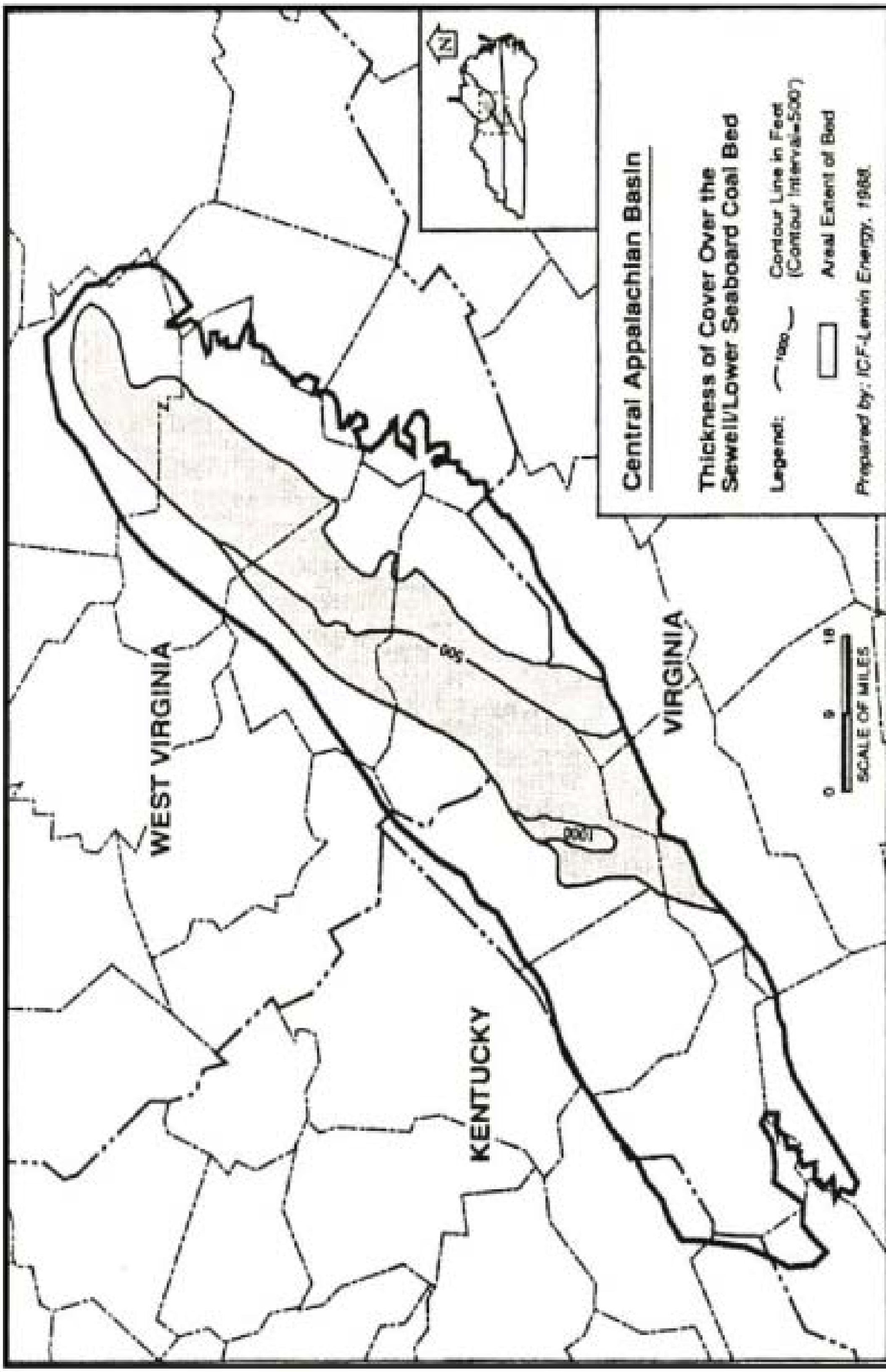
Isopach Map: Thickness of Cover Over the Fire Creek - Lower Horsepen Coalbed (Kelafant et al., 1988)

Figure A6-6



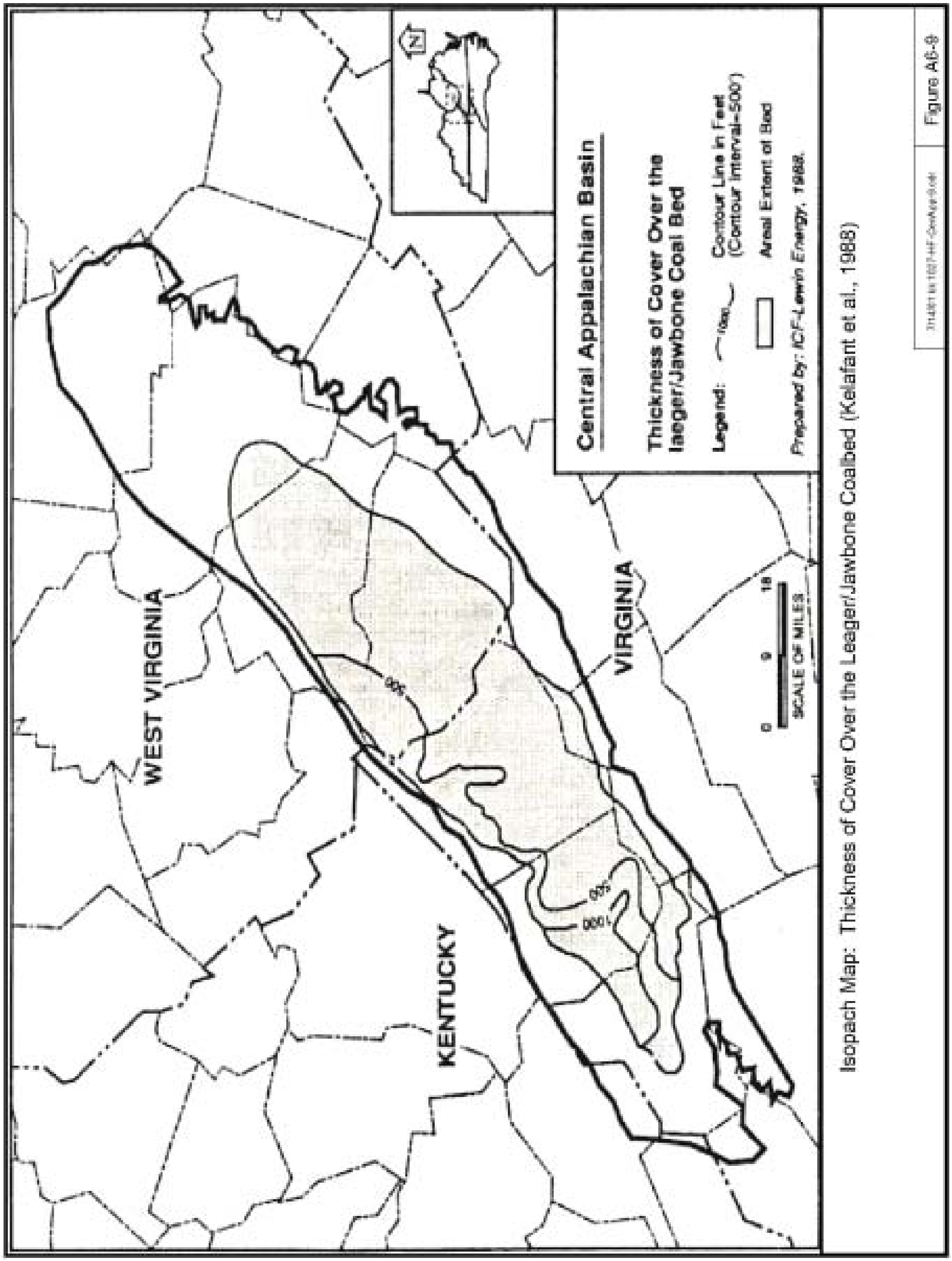
Isopach Map: Thickness of Cover Over Beckley - War Creek Coalbed (Kelafant et al., 1988)

Figure A6-7



Isopach Map: Thickness of Cover Over the Sewell/Lower Seaboard Coalbed (Kelafant et al., 1988)

Figure A6-8



Isopach Map: Thickness of Cover Over the Leager/Jawbone Coalbed (Kelafant et al., 1988)

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Attachment 7
The Northern Appalachian Coal Basin

The Northern Appalachian Coal Basin is the northernmost of the three basins comprising the Appalachian Coal Region of the eastern United States, and includes parts of the States of Pennsylvania, West Virginia, Ohio, Kentucky, and Maryland (Figure A7-1). The basin trends northeast-southwest and the Rome Trough, a major graben structure, forms the southeastern and southern structural boundaries (Kelafant et al., 1988). The basin is bounded on the northeast, north, and west by outcropping Pennsylvanian-aged sediments (Kelafant et al., 1988). The basin lies completely within the Appalachian Plateau geomorphic province, covering an area of approximately 43,700 square miles (Adams et al., 1984 as cited in Pennsylvania Department of Conservation and Natural Resources, 2002). It consists of six Pennsylvanian age coal units, and contains an estimated 61 trillion cubic feet of coalbed methane (Kelafant et al., 1988). Coal seam depths range from surface outcrops to up to 2,000 feet below ground surface, with most coal occurring at depths shallower than 1,000 feet (Quarterly Review, 1993). Annual coalbed methane production stood at 1.41 billion cubic feet in 2000 (GTI, 2002).

7.1 Basin Geology

The six Pennsylvanian aged coal zones located within the Northern Appalachian Coal Basin are the Brookville-Clarion, Kittanning, Freeport, Pittsburgh, Sewickley, and the Waynesburg. These coal units are contained within the Pottsville, Allegheny, and the Monongahela Groups (Figure A7-3) (Kelafant et al., 1988).

In the Northern Appalachian Basin, the Pottsville stratigraphic group is generally 200 to 300 feet thick, and thins to the north and west into Ohio and Pennsylvania (Kelafant et al., 1988). The coals in this group are interbedded with fluvial and deltaic sands and shales and are capped by marine limestones and shales (Kelafant et al., 1988). Deposition of this group took place on irregular Mississippian terrain, forming thin and erratic coals (Kelafant et al., 1988).

The Allegheny Group reaches a maximum thickness of 200 to 300 feet in western Maryland and thins westward to about 150 to 200 feet in Ohio. Deposition of this group occurred as cyclothem-type sedimentation, resulting in a complex sequence of lenticular, thin- to massive-bedded subgraywacke, shale, and mudstone interbedded with clays and coal (Kelafant et al., 1988). Due to their alluvial and delta plain depositional environments, Allegheny coals, which include the Brookville/Clarion, Kittanning, and the Freeport, are 2 to 6 feet thick and aerially extensive (Kelafant et al., 1988). The coalbeds decrease in number from the eastern to the western edge of the basin (Kelafant et al., 1988).

The Monongahela Group was deposited primarily in lacustrine and swamp environments. Some of the most important economic coals of the basin were deposited in large lakes, such as the Pittsburgh and Sewickley coals (Kelafant et al., 1988). The Monongahela Group is thickest along the Monongahela River at 400 feet and thins to 250 feet in the southwest along the Ohio River. Shales, mudstones, and freshwater limestones are the major rock types of the Group (Kelafant et al., 1988). The Waynesburg coals are also contained within the Monongahela Group. In general, the coalbeds of the Monongahela Group are laterally extensive.

The total thickness of the Pennsylvanian-aged coal system averages 25 feet; however, better-developed seams within the coal zones can increase in thickness by up to twice the average (Quarterly Review, 1993). Within the Pennsylvanian Coal System, the deepest coal, the Brookville-Clarion, ranges in depth from surface exposures in anticlines to 2,000 feet below ground surface. The Kittanning Group reaches a maximum depth of 2,000 feet and is approximately 800 feet deep in more than half the area in which the group occurs. The distance between the Upper and Lower Kittanning is approximately 100 feet (Kelafant et al., 1988). Freeport coals are at a maximum depth of 1,800 feet in the central portion of the Northern Appalachian Coal Basin. The Upper and Lower Freeport are separated vertically by a distance of 40 to 60 feet (Kelafant et al., 1988). The Pittsburgh coals achieve a maximum depth of 1,200 feet and roughly half of the coals can be found at depths greater than 400 feet (Kelafant et al., 1988). Sewickley coals are deeper than 400 feet with the deepest coals located at 1,200 feet below ground surface (Kelafant et al., 1988). The final and youngest group discussed here, the Waynesburg group, is the shallowest, reaching a maximum depth of 800 feet in the center of the basin. Figures A7-4 through A7-9 (adapted from Kelafant et al., 1988) are isopach maps of sediment cover for the six major coal zones of the Appalachian Coal Basin.

7.2 Basin Hydrology and USDW Identification

The Northern Appalachian Basin is situated in the Appalachian Plateaus physiographic province of the region. The primary aquifer in this area is a Pennsylvanian sandstone aquifer underlain by limestone aquifers (National Water Summary, 1984). Water wells are typically 75 to 100 feet in depth in the Pennsylvanian aquifer and commonly produce one to five gallons per minute of water (National Water Summary, 1984). The primary aquifers in the Maryland portion of the basin are Appalachian sedimentary aquifers, which are mostly sandstones, shales, and siltstones with some limestone, dolomite, and coal. Water wells here are typically 30 to 400 feet in depth and usually produce 10 to 100 gallons per minute of water (National Water Summary, 1984).

In Ohio, the primary aquifers are sandstone aquifers, shaly sandstone and carbonate aquifers, and coarse-grained aquifers (comprised of alluvium and glacial outwash) associated with river valleys (National Water Summary, 1984). Water wells within these aquifers typically range from 25 to 300 feet in depth, and common water production rates vary between 1 and 500 gallons per minute (National Water Summary, 1984).

In Pennsylvania, the primary aquifers are sandstone and shale aquifers, with smaller unconsolidated sand and gravel aquifers surrounding river courses (National Water Summary, 1984). Well depths in the sandstone and shale aquifers in Pennsylvania are usually 80 to 200 feet in depth, and the wells typically produce 5 to 60 gallons per minute of water (National Water Summary, 1984).

In West Virginia, the primary aquifer is an Upper Pennsylvanian-aged aquifer consisting of the Dunkard, Monongahela, and Conemaugh Groups (National Water Summary, 1984). This aquifer consists of nearly horizontal beds of shale, sandstone, siltstone, coal, and limestone (National Water Summary, 1984). Water wells typically extend from 50 to 300 feet in depth in this area of West Virginia, and commonly produce 1 to 30 gallons per minute of water (National Water Summary, 1984).

Individual states containing portions of the basin have developed various maps and documents locating underground sources of drinking water (USDWs) and aquifers within their state boundaries, mostly as a part of their respective Underground Injection Control (UIC) Programs. EPA’s Regional Office also has information concerning the location of these resources, as not all states within the Northern Appalachian Coal Basin have primacy over their UIC Program. Water quality data from eight historic Northern Appalachian Coal Basin projects show that estimated total dissolved solids (TDS) levels ranged from 2,000 to 5,000 milligrams per liter (mg/L) at depths ranging from 500 to 1,025 feet below ground surface (Zebrowitz et al., 1991), well within EPA's water quality criterion for a USDW of less than 10,000 mg/L of TDS (40 CFR §144.3).

Most states within the Northern Appalachian Basin, including Kentucky, Ohio, and West Virginia have mapped the interface between saline and freshwater aquifers. For Maryland and Pennsylvania, no maps have been identified that define the interface between saline and freshwater aquifers. In Maryland, a deep well drilled in southern Garrett County encountered the fresh/saltwater interface at a depth of 940 feet (Duigon and Smigaj, 1985). Groundwater in Pennsylvania deeper than 450 feet is not considered to be a USDW (Platt, 2001) because of the existence of non-water producing shale from 450 to 1000 feet, and TDS levels in water below this shale that are typically greater than 100,000 mg/L. The following table contains information concerning the relative location of potential USDWs and potential methane-bearing coalbeds in the Northern Appalachian Coal Basin.

As shown in Table A7-1, coalbeds with methane production potential in the Northern Appalachian Basin do occur within USDWs, indicating the potential for impact. West Virginia’s interface line between fresh and saline water (Foster, 1980) is based on a qualitative assessment, Ohio’s interface line is based on a TDS level of 3,000 mg/L (Sedam and Stein, 1970), and Kentucky’s interface line is based on a TDS level of 1,000 mg/L (Hopkins, 1966). In Maryland, the fresh water distinction was probably made based on a TDS level of 1,000 mg/L, as the reference refers to sodium and chloride concentrations of 1,800 mg/L and 2,900 mg/L as “high levels” (Duigon and Smigaj, 1985).

Table A7-1. Relative Locations of USDWs and Methane-Bearing Coalbeds

Northern Appalachian Coal Basin, States and Coal Groups	Pennsylvania		West Virginia		Ohio		Kentucky		Maryland	
	Depth to top of Coal (ft)	Depth to Base[3] of Fresh Water (ft)	Depth to top of Coal[2] (ft)	Depth to Base[4] of Fresh Water[1] (ft)	Depth to top of Coal[2] (ft)	Depth to Base[6] of Fresh Water[1] (ft)	Depth to top of Coal[2] (ft)	Depth to Base[5] of Fresh Water <1,000 mg/L TDS (ft)	Depth to top of Coal[2] (ft)	Depth to Base[7] of Fresh Water[1] (ft)
Waynesburg	0 to 800		0 to 800		0 to 400		0 to <400		0 to <400	
Sewickly	0 to 1200		0 to 1200		0 to < 800		0 to <400		0 to <400	
Pittsburgh	0 to 1200		0 to 1200		0 to 800		0 to <400		0 to <400	
Freeport	0 to 1600	~ 450	0 to 1600	~ 150 to 500	0 to <1200	~ 100 to 500	0 to <400	~ 100 to 500	0 to <400	~ 940
Kittanning	0 to 2000		0 to 2000		0 to <1200		0 to <400		0 to <400	
Brookville/Clarion	<400 to 2000		<400 to 2000		< 400 to 1200		<800		<800	

[1] Note: The base of "fresh water" is not necessarily the base of the USDW. Fresh water is within the USDW and the base of fresh water is above the base of the USDW. "Fresh water" is water with <1000 mg/L TDS.

[2] Kelafant et al., 1988

[3] Platt, USEPA Region 3, personal communication 2001

[4] Foster, 1980

[5] Hopkins, 1966 and USGS, 1973

[6] Sedam and Stein, 1970 and USGS, 1971

[7] Duigon, 1985

Therefore, in these states, the depth to the 10,000 mg/L level of TDS in groundwater is potentially and likely deeper than the depths presented above (Table A7-1). This assumption is confirmed by a structure elevation map (Figure A7-6) of the Upper and Lower Freeport Sandstones of the Upper Allegheny Group (Figure A7-3) in Ohio. With the increasing depth of these stratigraphic units toward the basin center, much of the formation waters in these units south of the easternmost counties in Ohio contain TDS levels in excess of 10,000 mg/L (Vogel, 1982). Likewise, the Pittsburgh Group Coals in Pennsylvania range in depth from outcrop to 1,200 feet below ground surface (Figure A7-7). Over this length of "dip", it is likely that the coals intersect drinking water aquifers before they reach depths where TDS levels exceed the 10,000 mg/L TDS water quality criterion of a USDW.

7.3 Coalbed Methane Production Activity

Coalbed methane has been produced in commercial quantities from the Pittsburgh coalbed of the Northern Appalachian Coal Basin since 1932 (Lyons, 1997), after the 1905 discovery of the Big Run Field in Wetzel County, West Virginia (Hunt and Steele, 1991). Coalbed methane production development in the Northern Appalachian Basin has lagged, however, due to insufficient reservoir knowledge, inadequate well completion techniques, and coalbed gas ownership issues revolving around whether the gas is owned by the mineral owner or the oil and gas owner (Zebrowitz et al., 1991). Annual coalbed methane production stood at 1.41 billion cubic feet in 2000 (GTI, 2002). As of October 2002, 185 coalbed methane wells were producing coalbed methane in Pennsylvania (Pennsylvania Department of Conservation and Natural Resources, 2002). Discharge of produced waters has also proven to be problematic (Lyons, 1997) for coalbed methane field operators in the Northern Appalachian Coal Basin.

Some operators in the Northern Appalachian Coal Basin and several test projects are discussed below. As of 1993, O'Brien Methane Production, Inc. had at least 20 wells in southern Indiana County, Pennsylvania (Quarterly Review, 1993). They received a water treatment and discharge permit that allowed O'Brien to discharge produced water into Blacklick Creek. The wells in O'Brien's field were hydraulically fractured with water and sand. Nitrogen was being contemplated for future fracturing. O'Brien's operations have since been assumed by Belden and Blake. BTI Energy, Inc. also had a few coalbed wells in northern Fayette County, Pennsylvania. Two were completed in 1993 and the firm held permits for eight additional wells.

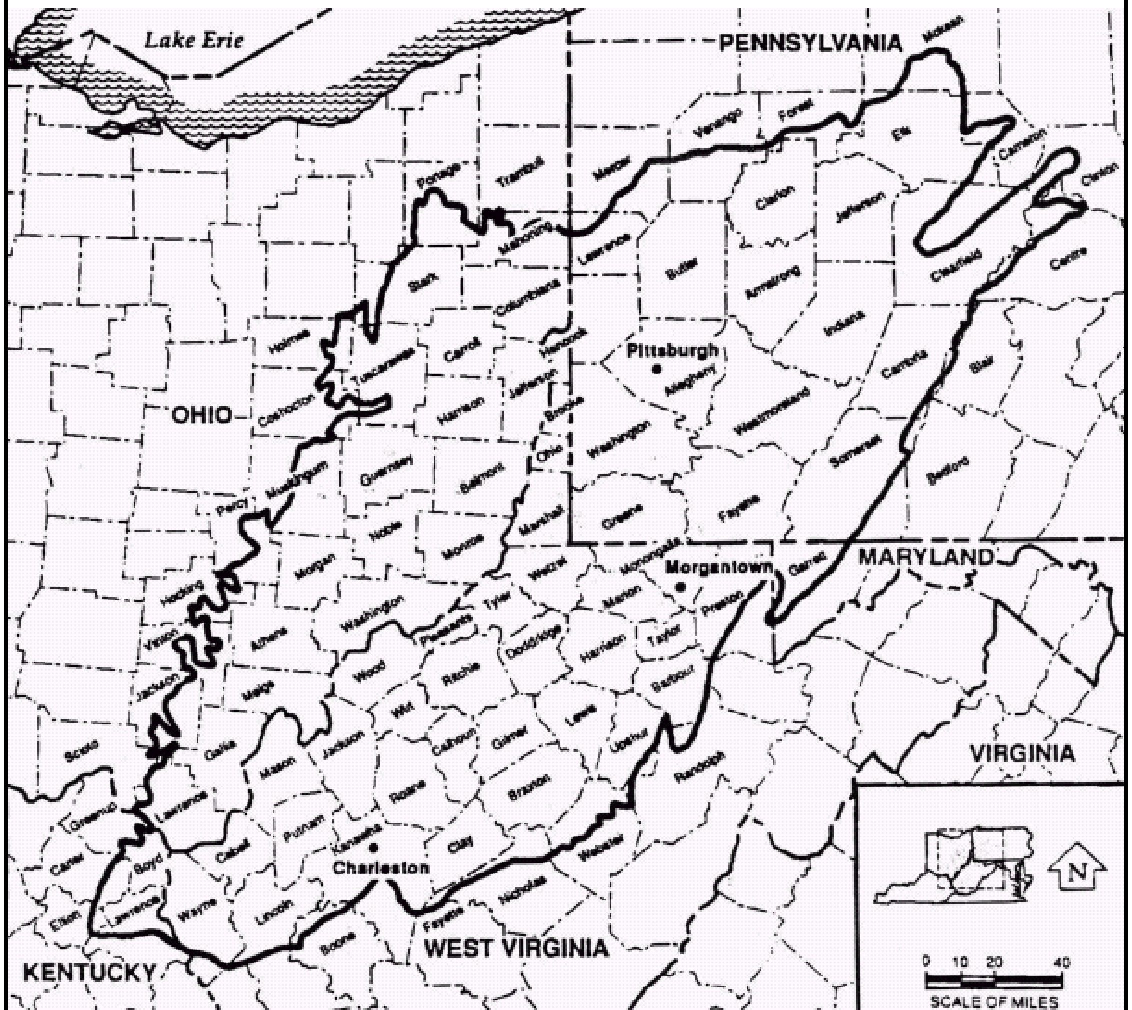
Other projects in the basin included the Lykes/Emerald Mines Project of the United States Bureau of Mines (USBM) and the Penn State University/Carnegie Natural Gas/U.S. Steel Wells Project, both in Greene County, Pennsylvania. Depths to the top of the Pittsburgh coals in Greene County range from 800 to 1,200 feet below ground surface (Kelafant et al., 1988). Hydraulic fracturing fluids included water and sand, and nitrogen foam and sand (Hunt and Steele, 1991). The Christopher Coal Company/Spindler Wells Project, which took place from 1952 to 1959, fractured one well with 12 quarts of nitroglycerin (Hunt and Steele, 1991). In the Vesta Mines Project of Washington County, Pennsylvania, the USBM used gelled water and sand to complete five wells in the Pittsburgh Seam (Hunt and Steele, 1991).

Within the State of Pennsylvania, there have been complaints of methane migrating into water supplies (Markowski, 2001). According to the Pennsylvania Department of Conservation and Natural Resources (2002), none of these complaints were linked specifically to hydraulic fracturing of coalbed methane wells. During a telephone interview (Markowski, 2001), Ms. Markowski stated methane contamination is due to the fact that many coalbed methane wells in southwestern Pennsylvania are completed in abandoned mine shafts. A puncture in the roof of the mineshaft provides a migration pathway for methane into overlying groundwater. These wells are known as gob wells, and are not usually hydraulically fractured or stimulated.

7.4 Summary

Based on available information, coal seams with methane production potential are located within USDWs throughout the Northern Appalachian Coal Basin, and hydraulic fracturing takes place in this basin. Because most of the coal strata dip, a well's location within the basin determines whether it is within a USDW, and whether the potential for impact exists. For example, in the Pittsburgh Coal Zone in Pennsylvania, the depth to the top of this coal zone varies from outcrop to about 1,200 feet in the very southwestern corner of the state. The approximate depth to the bottom of the USDW is 450 feet. Therefore, production wells operating down to approximately 500 feet could potentially be hydraulically connected to the USDW. However, those wells operating at depths greater than 900 feet would probably not be hydraulically connected to the USDW, unless a fracture extending beyond the coal layers to the shallower aquifer was to occur.

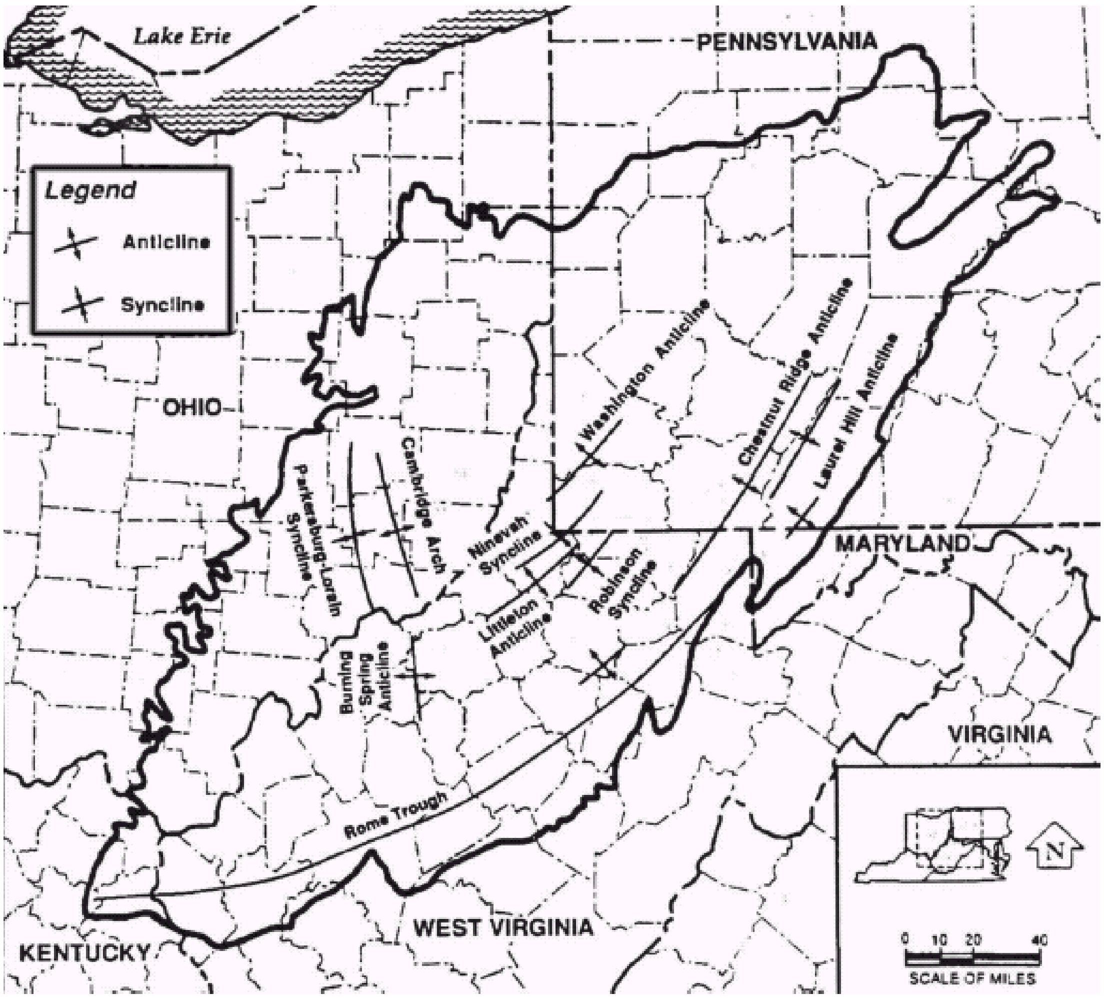
Milici (2002) indicated that the Pittsburgh Coal in Pennsylvania is mined out along its outcrop and the remaining coal resources are deeper (> 450 feet) in the basin. While this situation would greatly minimize the possibility of water quality impacts for this coal zone in Pennsylvania, the potential for contamination from the Pittsburgh coalbeds in other states within the basin still exists (see Table A7-1).



Index Map Showing County Names (Kelafant et al., 1988)

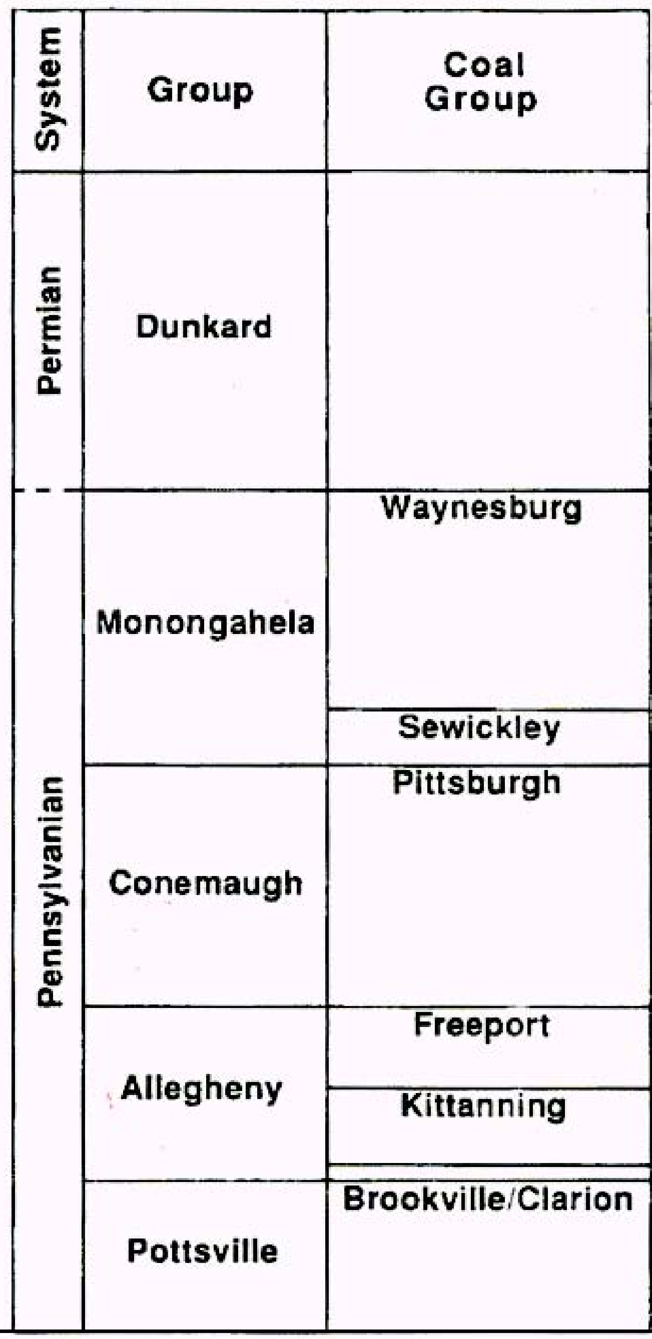
7/14/01 kk 1027-HF-NorApp-1.cdr

Figure A7-1



Structure Map (Kelafant et al., 1988)

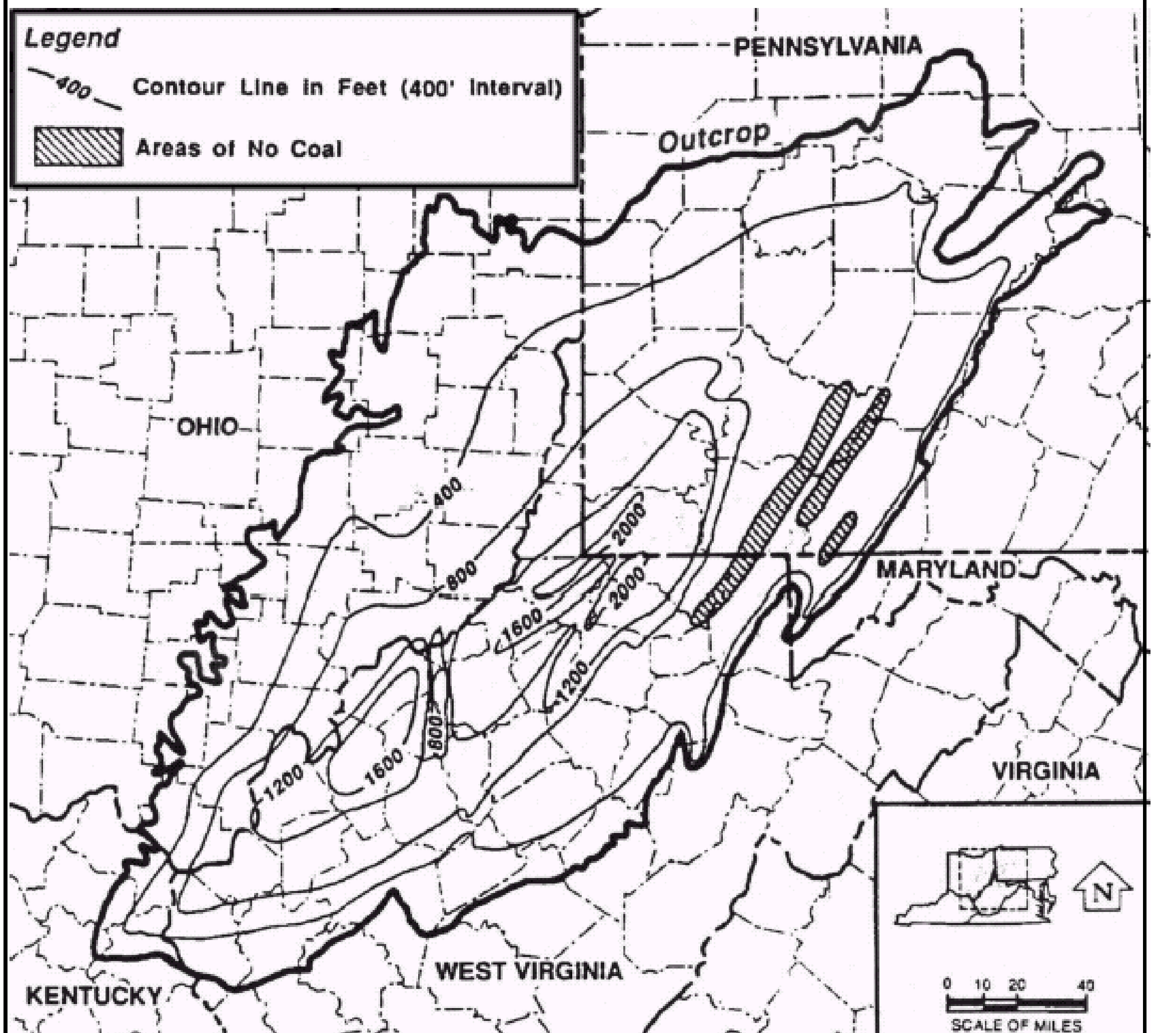
7/14/01 kk 1027-HF-NorApp-2.cdr | Figure A7-2



Generalized Stratigraphic Column of the Northern Appalachian Coal Basin
(Kelafant et al., 1988)

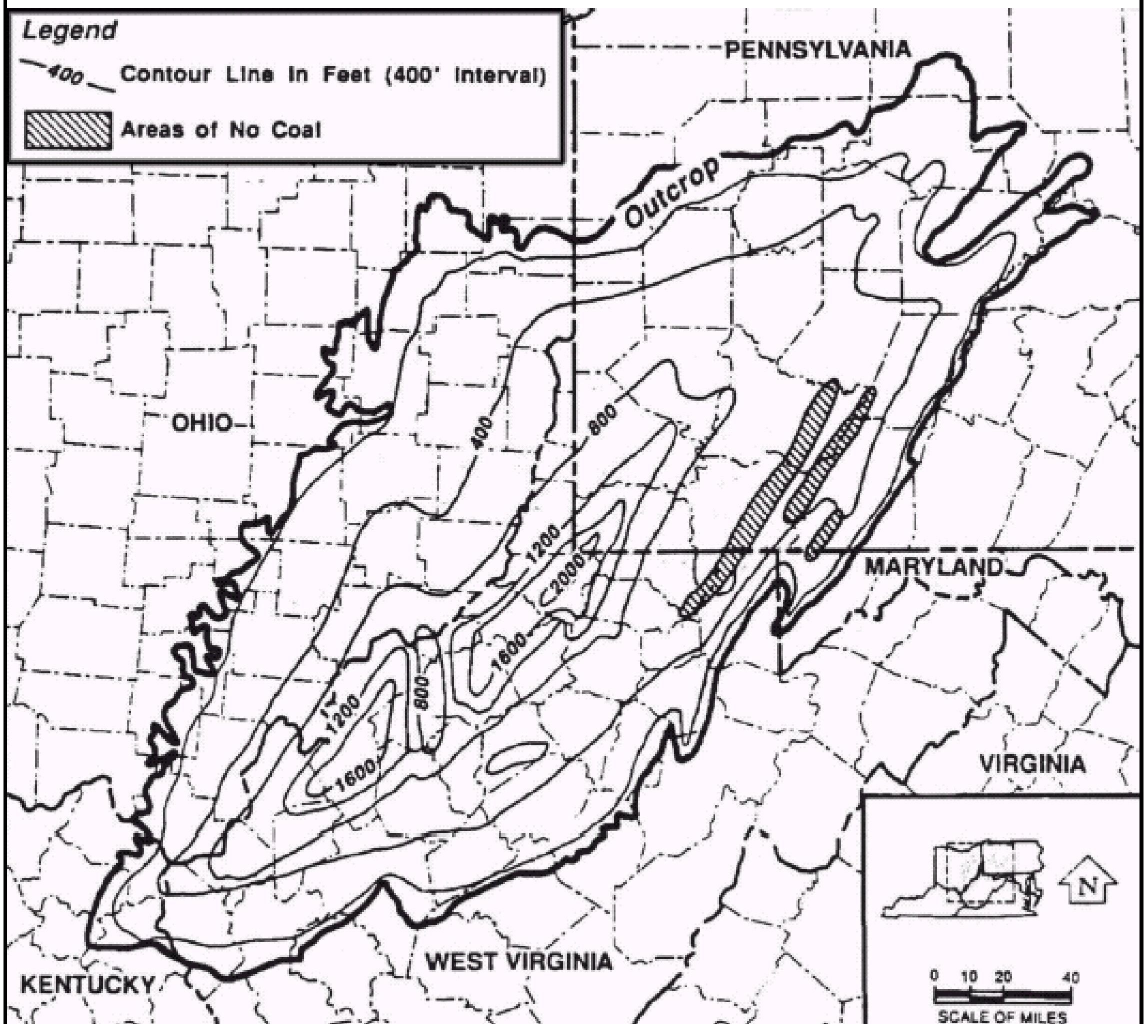
7/14/01 kk 1027-HF-NorApp-3.cdr

Figure A7-3



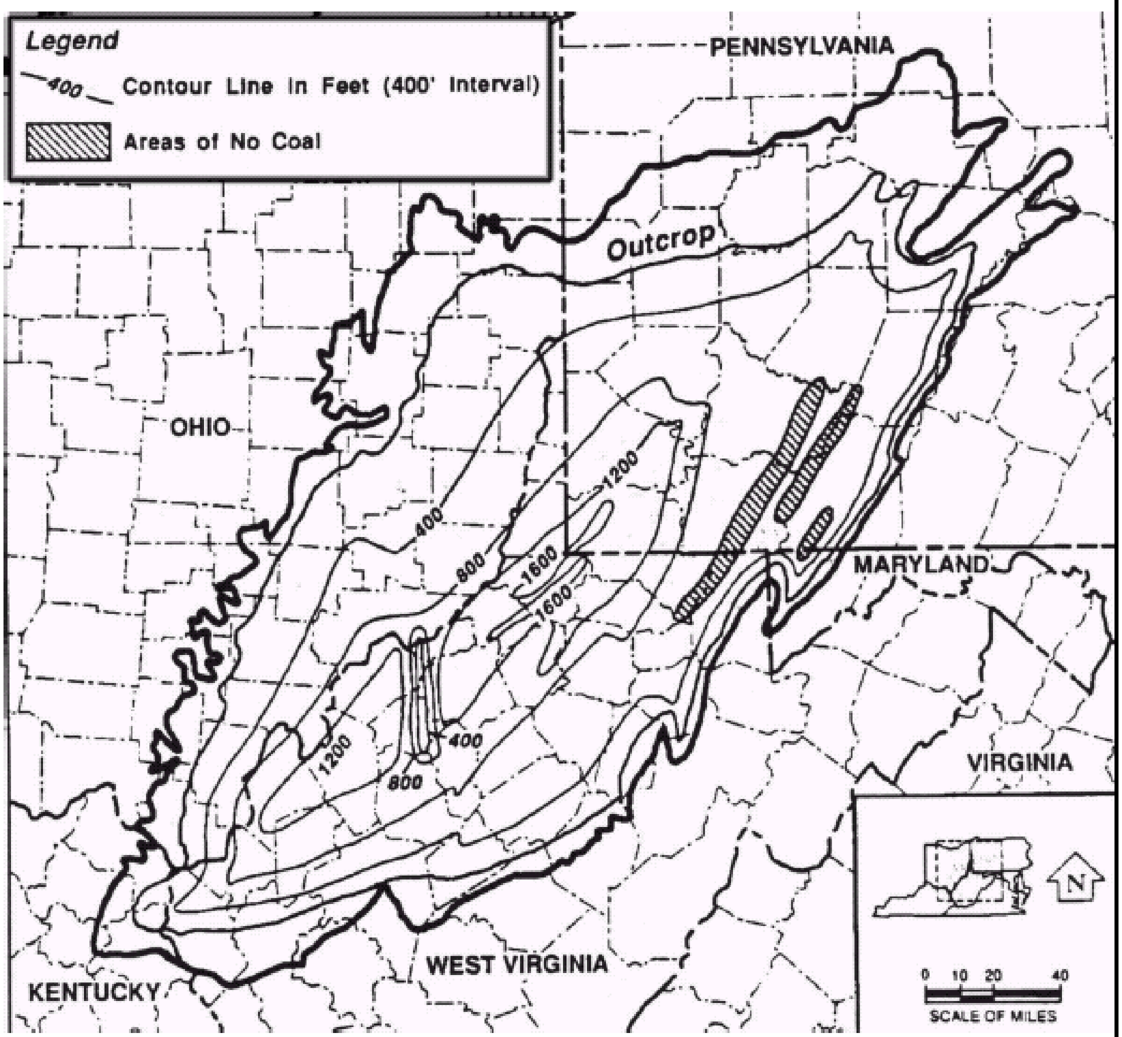
Isopach Map: Depth of Cover to the Brookville/Clarion Group Coals
(Kelafant et al., 1988)

7/14/01 kk 1027-HF-NorApp-4.cdr | Figure A7-4



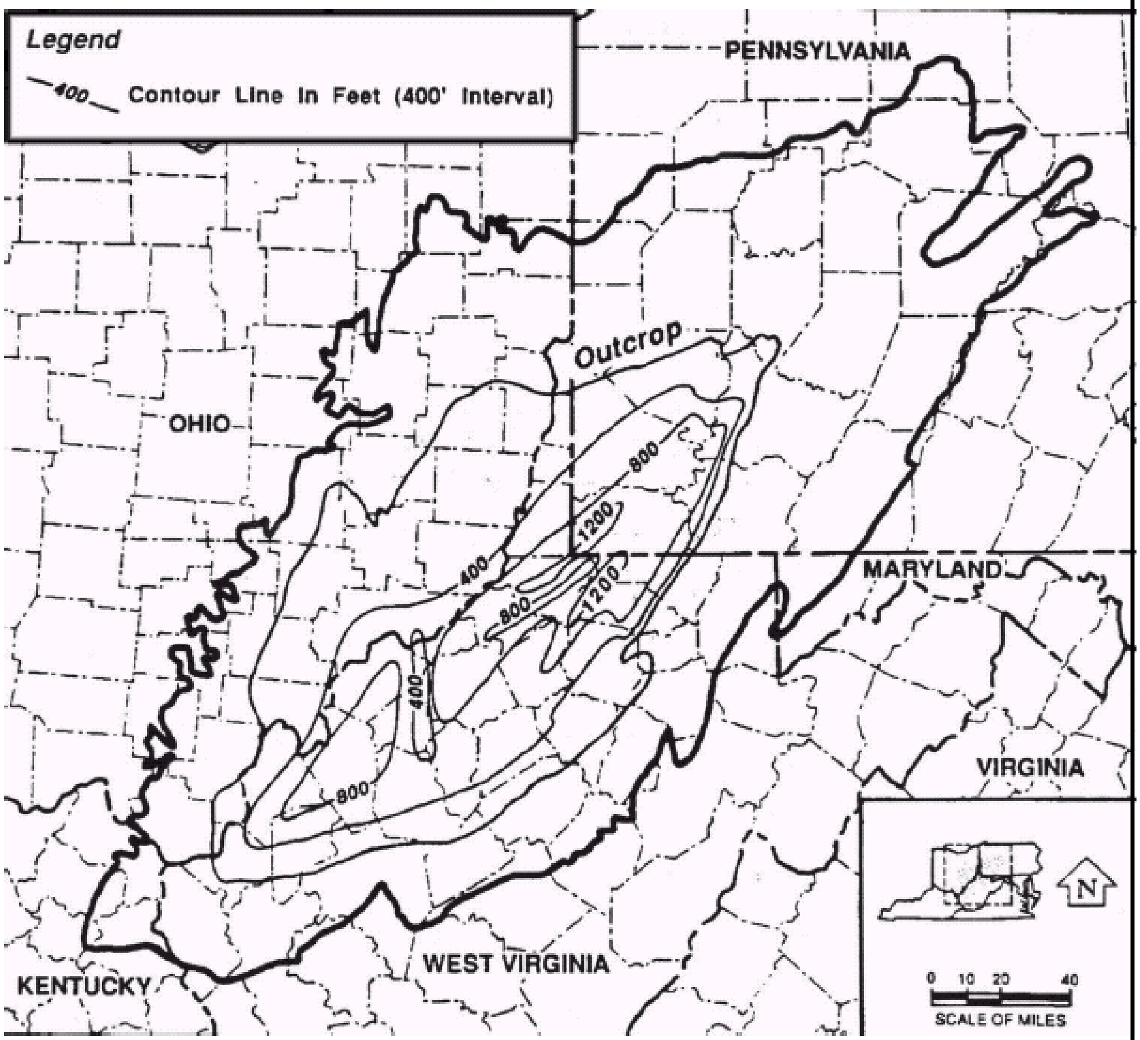
Isopach Map: Depth of Cover to the Kittanning Group Coals
(Kelafant et al., 1988)

7/14/01 kk 1027-HF-NorApp-5.cdr | Figure A7-5



Isopach Map: Depth of Cover to the Freeport Group Coals
(Kelafant et al., 1988)

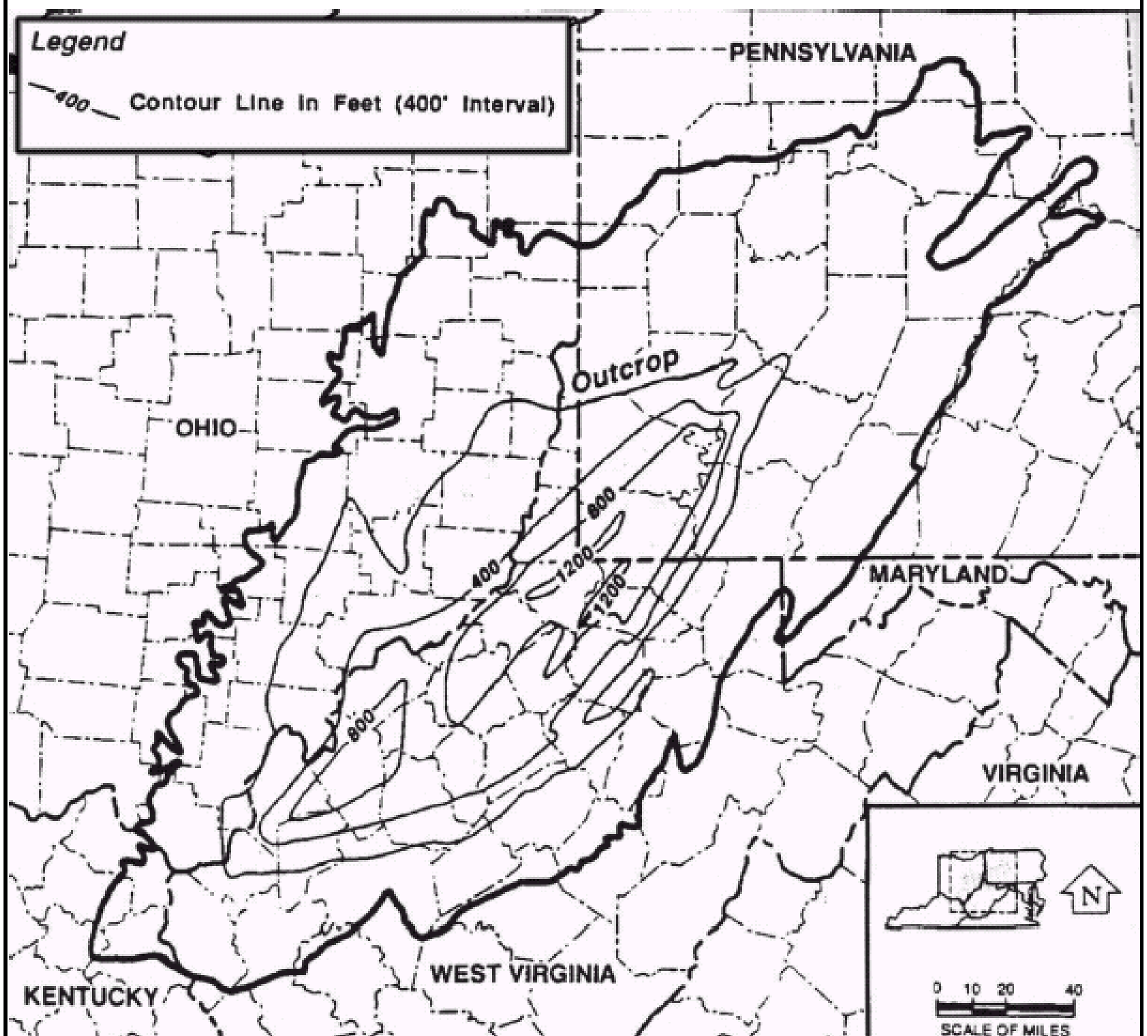
7/14/01 kk 1027-HF-NorApp-6.cdr | Figure A7-6



Isopach Map: Depth of Cover to the Pittsburgh Group Coals
(Kelafant et al., 1988)

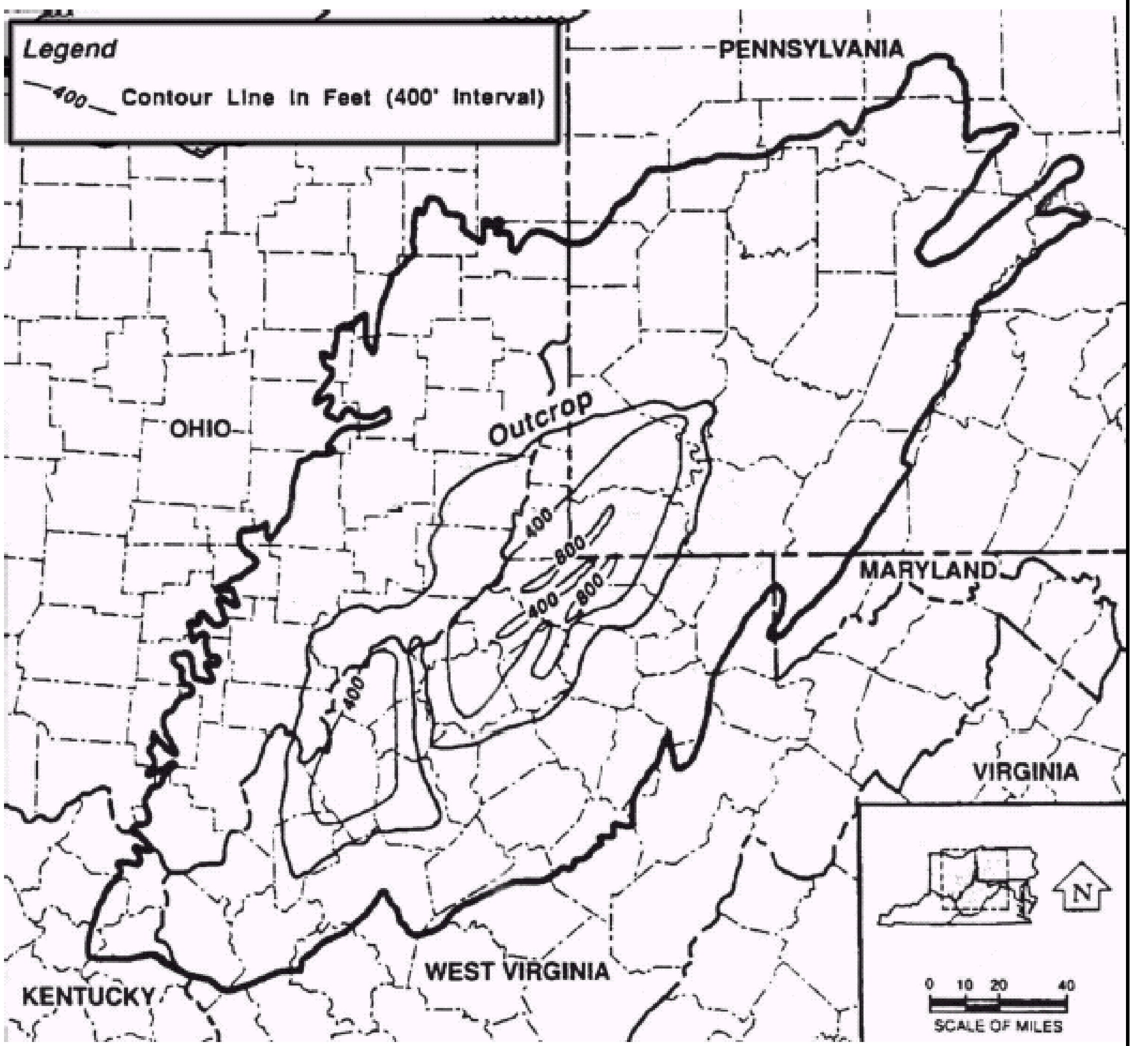
7/14/01 kk 1027-HF-NorApp-7.cdr

Figure A7-7



Isopach Map: Depth of Cover to the Sewickley Group Coals
(Kelafant et al., 1988)

7/14/01 kk 1027-HF-NorApp-8.cdr | Figure A7-8



Isopach Map: Depth of Cover to the Waynesburg Group Coals
(Kelafant et al., 1988)

7/14/01 kk 1027-HF-NorApp-9.cdr | Figure A7-9

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Attachment 8
The Western Interior Coal Region

The Western Interior Coal Region comprises three coal basins, the Arkoma, the Cherokee, and the Forest City Basins, and encompasses portions of six states: Arkansas, Oklahoma, Kansas, Missouri, Nebraska, and Iowa (Figure A8-1). The Arkoma Basin covers about 13,500 square miles in Arkansas and Oklahoma, with an estimated 1.58 to 3.55 trillion cubic feet (Tcf) of gas reserves, primarily in the Hartshorne coals (Quarterly Review, 1993).

The Cherokee Basin is part of the Cherokee Platform Province, which covers approximately 26,500 square miles (Charpentier, 1995) in Oklahoma, Kansas, and Missouri. The basin contains an estimated 1.38 million cubic feet of gas per square mile (Stoeckenger, 1990) in the targeted Mulky, Weir-Pittsburg, and Riverton coal seams of the Cherokee Group (Quarterly Review, 1993). In total, the basin contains approximately 36.6 billion cubic feet (Bcf) of gas. However, the Petroleum Technology Transfer Council (1999) indicates that there are nearly 10 Tcf of gas in eastern Kansas alone. The Forest City Basin covers about 47,000 square miles (Quarterly Review, 1993) in Iowa, Kansas, Missouri, and Nebraska, and contains an estimated 1 Tcf of gas (Nelson, 1999). For the entire region, coalbed methane production was 6.5 Bcf in 2000 (Gas Technology Institute (GTI), 2002).

8.1 Basin Coals

The Arkoma Basin is the southernmost of the three basins comprising the Western Interior Coal Region, and is bounded structurally by the Ozark Dome to the north, the Central Oklahoma Platform and Seminole Uplift on the west, and the Ouachita Overthrust Belt to the south (Quarterly Review, 1993). Middle Pennsylvanian coalbeds occur within the Hartshorne and McAlester Formations (Figure A8-2), as well as the Savanna and Boggy Formations (Quarterly Review, 1993).

The Cherokee Basin is the central basin of the Western Interior Coal Region, and is bounded on the east and southeast by the Ozark Dome, on the west by the Nehama Uplift, and on the north by the Bourbon Arch (Quarterly Review, 1993). Principal coals occur in the Krebs and Cabaniss Formations of the middle Pennsylvanian Cherokee Group (Figure A8-3).

The Forest City Basin (Figure A8-4), the northernmost basin of the Western Interior Coal Region, is a shallow cratonic depression bounded by the Nemaha Ridge to the west, the Thurman-Redfield structural zone to the north, the Mississippi River Arch to the east, and the Bourbon Arch to the south (Bostic et al., 1993). Methane-bearing coals occur in the middle Pennsylvanian Cherokee and Marmaton Groups, with the Cherokee Group being of primary interest (Tedesco, 1992).

8.1.1 Arkoma Basin Coals

The Hartshorne coals of the Hartshorne Formation are the most important for coalbed methane production in the Arkoma Basin. Their depths range from 600 to 2,300 feet in two productive areas in southeastern Oklahoma (Quarterly Review, 1993). Iannacchione and Puglio (1979) estimated that 58 percent of the coalbed methane in the Hartshorne coals in southeastern Oklahoma occurs at 500- to 1,000-foot depths. These coals can reach depths of greater than 5,000 feet, and are three to nine feet thick (Quarterly Review, 1993). Depths to the top of the Hartshorne coal in southeastern Oklahoma range from 380 to 1,540 feet (Friedman, 1982). As of March 2000, there were 377 coalbed methane wells in eastern Oklahoma, ranging in depth from 589 to 3,726 feet (Oklahoma Geological Survey, 2001).

8.1.2 Cherokee Basin Coals

The primary coal seams targeted by operators in Kansas are the Riverton Coal of the Krebs Formation and the Weir-Pittsburg and Mulky coals of the Cabaniss Formation (Quarterly Review, 1993). The Riverton and Weir-Pittsburg seams are about 3 to 5 feet thick and range from 800 to 1,200 feet deep (Quarterly Review, 1993). The Mulky Coal, which ranges up to 2 feet thick, occurs at depths of 600 to 1,000 feet (Quarterly Review, 1993).

8.1.3 Forest City Basin Coals

Individual coal seams in the Cherokee Group in the Forest City Basin range from a few inches to about 4 feet thick, with some seams up to 6 feet thick (Brady, 2002; Smith, 2002). Cumulative maximum coal thickness within the Cherokee Group is about 25 to 30 feet (Brady, 2002; Smith, 2002). Depths to the top of the Cherokee Group coals range from surface exposures in the shallower portion of the basin in southeastern Iowa, to about 1,220 feet in the deeper part of the basin, in northeastern Kansas (Bostic et al., 1993). At one location in Nebraska, the depth to the Cherokee Group is about 1,396 feet, and the base is at a depth of 2,096 feet (Condra and Reed, 1959). Maximum thickness of the Cherokee and Marmaton Groups is about 800 feet in the southeastern tip of Nebraska (Burchett, unpublished paper).

8.2 Basin Hydrology and USDW Identification

8.2.1 Arkoma Basin Hydrology and USDW Identification

In Arkansas, the Arkoma Basin falls within the Interior Highlands physiographic province (Figure A8-5). According to the National Water Summary (1984), there is no principal aquifer in this area, only small alluvial aquifers bounding the Arkansas River (Figure A8-5). In these alluvial aquifers, water wells typically penetrate to depths of 100 to 150 feet, and common well yields are in the order of 1,000 to 2,000 gallons of water per minute (National Water Summary, 1984). In Oklahoma, the Arkoma Basin is contained within the Ouachita and Central Lowland physiographic province (Figure A8-6). Much like in Arkansas, there are no principal aquifers in this portion of the state, but there are smaller alluvium and terrace deposits along the Arkansas, North Canadian, and Canadian Rivers (National Water Summary, 1984) that serve as aquifers (Figure A8-6). Marcher (1969) also identifies these smaller deposits as the most favorable for groundwater supplies. Water well depths in the alluvium and terrace deposits of the Arkansas River in Oklahoma typically range from 50 to 100 feet (National Water Summary, 1984). Water well production rates in all three aquifers commonly range from 100 to 600 gallons of water per minute in alluvium, and 50 to 300 gallons of water per minute in terrace deposits (National Water Summary, 1984).

Bill Prior, a geologist with the Arkansas Geological Commission, stated that within Arkansas, the Arkoma Basin was in the Arkansas River Physiographic Province, which lacks a true aquifer. Most of the rocks within this physiographic province are tight sandstones and shales, and most communities within the province use surface water supplies (Prior, 2001). Doug Hansen of the Arkansas Geological Commission said that there were a few scattered bedrock wells within the Arkoma Basin (Hansen, 2001). Total dissolved solids (TDS) levels in the McAlester Formation in Arkansas (which contains the Hartshorne coals; Potts, 1987) range between 55 to 534 milligrams per liter (mg/L) at depths ranging from 32.4 to 190 feet below land surface (Cordova, 1963). The base of fresh water in the area is about 500 to 2,000 feet below ground surface (Cordova, 1963). However, Cordova (1963) does not define "fresh water;" therefore, it is difficult to determine if the depths reported by Cordova coincide with the base of an underground source of drinking water (USDW).

Water quality test results from the targeted Hartshorne seam in Oklahoma have shown the water to be highly saline (Quarterly Review, 1993). Ken Luza, a geologist with the Oklahoma Geological Survey, stated that a hydrologic atlas prepared by the Oklahoma Geological Survey delineated a 5,000 mg/L TDS water quality contour line in a portion of the state, including the Arkoma Basin (Marcher, 1969; Marcher and Bingham, 1971). Maps such as these atlas maps show that, based on water quality and rock type, very little of the area falls within a zone "most favorable for groundwater supplies" or "moderately favorable for groundwater supplies." Most of the area falls within a zone designated as "least favorable for groundwater supplies" (Cardott, 2001). Pam Hudson, Manager of the

Geologic Section of the Oklahoma Corporation Commission, stated that the Commission has a series of maps, one for each county in Oklahoma, showing the depth to the 10,000 mg/L TDS line (Hudson, 2001). The water quality criterion for a USDW is a TDS level of less than 10,000 mg/L. The Oklahoma Corporation Commission maps are used to assist drillers in complying with state regulations that require oil and gas wells to be cased through USDWs.

The following table contains information concerning the relative location of potential USDWs and methane-bearing coalbeds in the Arkoma Basin.

Table A8-1 Relative Locations of USDWs and Potential Methane-Bearing Coalbeds, Arkoma Basin

Arkoma Coal Basin, States and Coal Group	**Arkansas**		**Oklahoma**	
	Depth to top of Coal [1] (ft)	Depth to base of Fresh Water [2,3] (ft)	Depth to top of Coal [1] (ft)	Depth to base of USDW [4] (ft)
Hartshorne Coals	0 to < 4,500	500 to 2000	> ~1000	< ~900

[1] Andrews et al., 1998
[2] Note: The base of “fresh water” is not the base of the USDW (depth to the base of the USDW is unknown or not available). Fresh water is within the USDW and the base of fresh water is above the base of the USDW. Cordova (1963) does not define “fresh water.”
[3] Cordova, 1963
[4] Oklahoma Corporation Commission Depth to Base of Treatable Water Map Series (2001)

Based on Table A8-1, it can be determined that in Arkansas, there is a possibility for the Hartshorne Coals to be located within a USDW, allowing the potential for impacts. The potential for impacts from fracturing coalbeds below the USDW is not known. Cordova (1963) does not specify the TDS level used to determine the depth of the base of fresh water in the Arkansas Valley region; he merely states that it is the depth to salt water, and he does not provide a definition of “salt water.” The position of a coalbed methane well within the basin would ultimately determine if coals and USDWs coincide, as the Hartshorne Coals are typically shallower on basin margins (Andrews et al., 1998) and progressively increase in depth toward the basin’s center (where they are potentially too deep to be located within a USDW).

8.2.2 Cherokee Basin Hydrology and USDW Identification

The Cherokee Basin underlies parts of the States of Kansas, Missouri, and Oklahoma. In Kansas, the Cherokee Basin is part of the Central Lowlands and Ozark Plateaus physiographic provinces (Figure A8-7). While the majority of this area does not contain a principal aquifer, the Ozark and Douglas aquifers (Figure A8-7) are contained in the basin (National Water Summary, 1984). The confined Ozark Aquifer, composed of weathered and sandy dolomites, typically contains water wells that extend from 500 to

1,800 feet in depth, commonly yielding 30 to 150 gallons of water per minute (National Water Summary, 1984). The usually unconfined Douglas Aquifer is channel sandstone of Pennsylvanian Age (National Water Summary, 1984). Water wells are usually 5 to 400 feet deep in this aquifer and typically produce 10 to 40 gallons of water per minute (National Water Summary, 1984).

In Missouri, only a very small portion of the basin falls within the Osage Plains area of the Central Lowlands physiographic province (Figure A8-8). The principal aquifers in this portion of Missouri are the Ozark and Pennsylvanian-Mississippian age aquifers (National Water Summary, 1984) (Figure A8-8). Water well depths in the Ozark Aquifer typically range from 200 to 1,700 feet, and those in the Pennsylvanian-Mississippian age aquifers typically range from 100 to 400 feet in depth (National Water Summary, 1984). Common well yields are 15 to 700 gallons of water per minute and 1 to 15 gallons of water per minute in the Ozark and Pennsylvanian-Mississippian aquifers, respectively (National Water Summary, 1984). Only a very small portion of the Cherokee Basin, bounded from the Forest City Basin to its north by the Bourbon Arch, falls within the State of Missouri (Figure A8-9). Jim Vandike, Chief of Missouri's Water Resources Branch at the Missouri Geological Survey, stated that only two public water supplies obtain water from Pennsylvanian strata, and those wells were outside of the Cherokee Basin (Vandike, 2001).

In Oklahoma, the Cherokee Basin lies within the Central Lowland physiographic province (Figure A8-6). In addition to the alluvium and terrace deposit aquifers previously discussed in the Arkoma Basin aquifer descriptions, this area also contains the Garber-Wellington and Vamoosa-Ada Aquifers (Figure A8-6), which are unconfined to confined sandstone with shale and siltstone aquifers (National Water Summary, 1984). The Vamoosa-Ada Aquifer contains some conglomerate aquifers as well. Water well depths in these two aquifers usually range from 100 to 900 feet, and wells typically produce from 100 to 300 gallons of water per minute (National Water Summary, 1984). At least half of the area of this basin in Oklahoma does not contain a principal aquifer (National Water Summary, 1984).

In Kansas, Al Macfarlane, of the Kansas Geological Survey, stated that the Ozark Aquifer was located in the Cherokee Basin in Kansas (Macfarlane, 2001). An Ozark Aquifer Extent map indicates that the "usable" part of the aquifer (defined as having less than 10,000 mg/L of TDS per Macfarlane; no definition of "usable" is provided by the map) covers the three southeastern-most counties (Bourbon, Crawford, and Cherokee) of the state (Figure A8-7) and parts of the adjacent four counties (Linn, Allen, Neosho, and Labette) (DASC Ozark Aquifer Extent Map, 2001c). Because the land surface elevation in that portion of the state is roughly 850 feet above sea level (DASC Kansas Elevation Map, 2001b) and the elevation of the base of the Ozark Aquifer is roughly 900 feet below sea level (Ozark Aquifer Base Map, 2001c), the base of the Ozark aquifer is roughly 1,750 feet below ground surface. Groundwater samples taken from lower Paleozoic aquifers in Kansas show TDS levels ranging from <500 to 5,000 mg/L (Figure A8-10) (Macfarlane and Hathaway, 1987), well within the range for a USDW.

Table A8-2 contains information concerning the relative location of potential USDWs and methane-bearing coalbeds in the Cherokee Basin. The table shows that all or part of the targeted coal seams could be coincident with a USDW, allowing the potential for impacts. Most past coalbed methane production activity within the Cherokee Basin took place in Kansas (Quarterly Review, 1993). However, coalbed methane production activity within the Cherokee Basin in Oklahoma has increased markedly in recent years (Hudson, 2001).

Table A8-2 Relative Locations of USDWs and Potential Methane-Bearing Coalbeds, Cherokee Basin

	Kansas		Missouri		Oklahoma	
Coal Group	Depth to top of Coal [1] (ft)	Depth to base of Fresh Water (USDW) [2] (ft)	Depth to top of Coal [1] (ft)	Depth to base of Fresh Water [3] (ft)	Depth to top of Coal [1] (ft)	Depth to base of Fresh Water (ft)
Mulky	600 to 1000	~ 1750	600 to 1000	N/A[4]	600 to 1000	N/A[4]
Weir-Pittsburg	800 to 1200		800 to 1200		800 to 1200	
Riverton	800 to 1200		800 to 1200		800 to 1200	

[1] Quarterly Review, 1993
[2] Ozark Aquifer extent and base, and Kansas elevation maps from the Kansas Data Access and Support Center (DASC) 2001b
above
[3] Missouri's Geological Survey, Water Resources Branch, claims no water supplies in these strata
[4] Not Available

8.2.3 Forest City Basin USDW Identification

The Forest City Basin includes parts of the States of Iowa, Kansas, Missouri, and Nebraska. In Iowa, the Forest City Basin lies within the Southern Iowa Drift Plain physiographic province (Figure A8-11). The most productive aquifer in this area is the dolomite and sandstone Jordan Aquifer (Figure A8-11). Wells in this aquifer commonly range in depth from 300 to 2,000 feet (some are as deep as 3,000 feet) and usually produce 100 to 1,000 gallons of water per minute (National Water Summary, 1984). This aquifer usually contains in excess of 1,500 mg/L TDS in the southern portion of the state (National Water Summary, 1984). Other aquifers used at various locations in the basin are found in the Silurian-Devonian age and in the Mississippian-age strata (Figure A8-11). Water wells in these aquifers range from 150 to 750 feet deep with variable production (Howes, 2002). Also contained within this basin in Iowa is a portion of the confined, poorly cemented sandstone Dakota aquifer (National Water Summary, 1984) (Figure A8-11). Water wells in this aquifer are typically 100 to 600 feet in depth, and commonly produce 100 to 250 gallons of water per minute (National Water Summary, 1984). An Iowa Division of Natural Resources Geological Survey Bureau geologist, Mary Howes, said that few towns in Iowa use Pennsylvanian strata for water, as they typically contain high concentrations of sulfate and TDSs (Howes, 2001). Most community water supplies in the southern portion of Iowa use surface water and shallow alluvial aquifers as drinking water sources, and there are a few wells in fractured bedrock. Private water supplies typically are derived from seepage wells, shallow bedrock wells, or purchased from a public supply (Howes, 2002).

In Kansas, the basin is located in the Lowlands physiographic province (Figure A8-7), and only the northeastern corner of the state falls within the Forest City Basin boundary. In addition to the Douglas Aquifers described above in the Cherokee Basin Aquifer descriptions, this portion of the Forest City Basin in Kansas also contains a glacial drift aquifer (is this and some alluvial aquifers adjacent to the Kansas River (National Water Summary, 1984) (Figure A8-7). In the glacial drift, wells are typically 10 to 300 feet in depth and usually produce 10 to 100 gallons of water per minute (National Water Summary, 1984). Wells in the alluvium are usually 10 to 150 feet deep and typically produce 10 to 500 gallons of water per minute (National Water Summary, 1984). The glacial drift aquifer’s base varies from about 850 to 1,300 feet above sea level (DASC, Glacial Drift Base Map, 2001a). Since the elevation of the land surface in this portion of Kansas is roughly between 1,000 and 1,400 feet above sea level (DASC, Kansas Elevation Map, 2001b), the aquifer appears to extend only to an approximate maximum depth of 150 feet below the ground surface.

In Missouri, the basin lies within the Central Lowland physiographic province (Figure A8-8). The principal aquifer in this area is a glacial-drift aquifer (Figure A8-8). In this aquifer, water wells are typically 100 to 250 feet in depth and produce 5 to 200 gallons of water per minute. In addition to this aquifer, alluvial deposits along the Missouri River are also developed for water (National Water Summary, 1984)(Figure A8-8). Well depths in the alluvium usually range from 80 to 100 feet in depth, and the wells typically produce 100 to 1,000 gallons of water per minute (National Water Summary, 1984). Two public supply wells in Cass County, Missouri, extract water from Pennsylvanian strata for the town of East Lynn. A map of groundwater quality within Paleozoic aquifers of Missouri (Figure A8-12) shows that within the Forest City Basin, water quality ranges from about 500 mg/L TDS to 40,000 mg/L TDS in deeper portions of the basin (Missouri Division of Geological Survey and Water Resources, 1967). A 10,000 mg/L TDS boundary line delineated in the Mississippian aquifers of Missouri (located directly below Pennsylvanian-age strata) includes portions of Cass, Jackson, Lafayette, Carroll, Saline, Ray, Clay, Caldwell, Clinton, and Platte Counties (Netzler, 1982) (Figure A8-8).

Only the southeastern tip of Nebraska (primarily Richardson County) falls within the limits of the Forest City Basin. The principal aquifers in this area are undifferentiated aquifers in Paleozoic-age rocks (National Water Summary, 1984) (Figure A8-13). Locally overlain by saturated Quaternary-age sand and gravel deposits, wells within this area are commonly 30 to 2,200 feet in depth, and produce about 10 to 200 gallons of water per minute. TDS levels in the water can be as high as 6,000 mg/L, but are usually less than 1,500 mg/L (National Water Summary, 1984). The Ground Water Atlas of Nebraska (Flowerday et al., 1998) indicates that Richardson County is within the Southeastern Nebraska Glacial Drift rock unit. The thickness of the aquifer in Richardson County is less than 100 feet and the depth to water is 30 to 200 feet. The information in the Ground Water Atlas of Nebraska (Flowerday et al., 1998) appears to be in conflict with the data presented by the U.S. Geological Survey in the National Water Summary (1984). Matt Jokel of the Nebraska Conservation and Survey Division said it is very difficult to obtain water in this portion of the state, and most people use valley fill materials and paleochannels as water supply sources. He also believes that the coal resources, which could possibly be used for methane extraction, are probably too deep to be located coincident with the shallow water supplies in the area (Jokel, 2001).

Table A8-3 contains information concerning the relative location of potential USDWs and potential methane-bearing coalbeds in the Forest City Basin.

Table A8-3 Relative Locations of USDWs and Potential Methane-Bearing Coalbeds, Forest City Basin

	Iowa		Kansas		Missouri		Nebraska	
Coal Group	Depth to top of Coal [1] (ft)	Depth to base of fresh water[3] (ft)	Depth to top of Coal [1] (ft)	Depth to base of fresh water [4] (ft)	Depth to top of Coal [1] (ft)	Depth to base of fresh water [5] (ft)	Depth to top of Coal[1,6] (ft)	Depth to base of fresh water [2,7] (ft)
Cherokee Group	0 to >230	N/A[8]	720 to 1220	~ 150	300 to 1100	N/A[8]	1220 to 1396	129 to 299

[1] Bostic et al., 1993
[2] Note: The base of "fresh water" is not the base of the USDW. Fresh water is within the USDW and the base of fresh water is above the base of the USDW.
[3] Howes, Iowa Geological Survey Bureau (2001) believes water quality data may be available to define this depth
[4] Glacial Drift base and Kansas elevation maps from the Kansas Data Access and Support Center (DASC), 2001b
[5] Maps (Netzler, 1982) sent by Missouri show the extent of aquifers containing less than 10,000 mg/L of TDS, but not depths
[6] Condra and Reed, 1959
[7] The Groundwater Atlas of Nebraska, (Flowerday et al., 1998)
[8] Not Available

Presently, there does not appear to be a USDW located at the same depth as the coals of the Cherokee Group in the Forest City Basin. However, very little is known about the coal resources of this basin (Quarterly Review, 1993). Further research is required to delineate the possible link between coalbed methane resources and USDWs in the Forest City Basin.

8.3 Coalbed Methane Production Activity

GTI places total coalbed gas production in the Western Interior Coal region at 6.5 Bcf for the year 2000 (GTI, 2002).

8.3.1 Arkoma Basin Production Activity

In 1989, Bear Production Company became the first company to target coalbed methane production from the Hartshorne Coals of the Arkoma Basin in Haskell County, Oklahoma (Quarterly Review, 1993). As of 1993, Bear Production had 38 wells in operation, Aztec Energy Corporation had 19 wells, and Redwine Resources, Inc. had 40 wells in the Arkoma Basin (Quarterly Review, 1993).

As of 1993, Bear Production was not fracturing its wells, but rather completing them as open holes without perforated casings (Quarterly Review, 1993). However, other production companies were fracturing their wells for methane production. Before 1992, water, linear gel, acid, and nitrogen foam fracturing fluids were used, with most operators using foam with small sand volumes (35,000 to 60,000 lbs) (Quarterly Review, 1993). In 1993, slick water fracturing fluids containing no proppant were becoming more common (Quarterly Review, 1993). Well fracturing data from 36 wells in the Spiro Southeast Field of LeFlore County, Oklahoma show that either water or nitrogen foam was the base fracturing fluid used to carry sand proppant into coal cleats (Andrews et al., 1998). Fracturing continues in the Arkoma Basin today, at least in Oklahoma, where undisclosed amounts of initial water production are “frac” waters introduced during fracture stimulation (Cardott, 2001). Both Wendell (2001) and Marshall (2001) outline current hydraulic fracturing practices within the Arkoma Basin, and Wendell (2001) includes acids, benzene, xylene, toluene, gasoline, diesel, solvents, bleach, and surfactants as detrimental hydraulic fracturing substances in his “lessons learned” category.

A search of the Oklahoma Coal Database, updated on January 17, 2001, indicated that over 360 coalbed methane wells had been completed in Haskell, Le Flore, and Pittsburg counties alone, targeting the Hartshorne, McAlester, and Savanna coals. Additional operators in the Arkoma Basin today include Continental Resources, SJM Inc., Brower O & G, Mannix Oil, and OGP Operating (Oklahoma Coal Database, 2001).

Apparently there is little to no coalbed methane activity in the Arkoma Basin in Arkansas, based on the Arkansas Geological Commission’s Web site, which states,

"…there exists the potential for coalbed methane production in this area of the state" (Arkansas Geological Commission, 2001). The low coalbed methane activity in this Basin is further confirmed by Andrews et al. (1998), which outlines Arkansas' restrictive field-spacing policy from the 1930s of only one well per 640-acre section for each producing zone in the Hartshorne. This policy effectively made exploration uneconomical. A change in field-spacing rules in 1995 has stimulated new interest among independent producers in Arkansas to develop methane from the Hartshorne coals (Andrews et al., 1998).

8.3.2 Cherokee Basin Production Activity

In the Cherokee Basin, unknown amounts of coalbed methane gas have been produced with conventional natural gas for over 50 years (Quarterly Review, 1993). Targeted coalbed methane production increased in the late 1980s, and at least 232 coalbed methane wells had been completed as of January 1993 (Quarterly Review, 1993). During this timeframe, development was centered on Montgomery County, Kansas, with the most active operators being Great Eastern Energy and Development Corporation with 81 wells, Kan Map Inc. with 47 wells, and Stroud Oil Properties Inc. with 35 wells, (Quarterly Review, 1993). In addition to these operators, Bonanza Energy Corporation, Conquest Oil Company, Foster Oil & Gas, Hunter, Quantum Energy, Uranus, and U.S. Exploration had active development programs, and Derrick Industries was planning a program (Quarterly Review, 1993).

The coalbed methane wells were typically fractured with water or nitrogen-based fluids and sand, although the shallower Mulky coal received fracturing treatments of 40-pound linear gel and sand (Quarterly Review, 1993). On average, 5,000 pounds of sand were used per foot of coal (Quarterly Review, 1993). Another technique used in Kansas consists of injecting 4 barrels of 15 percent hydrochloric acid mixed with 16 barrels of potassium chloride and 15,000 standard cubic feet of nitrogen (Stoeckinger, 1990). In the Sycamore Valley field in Kansas, Stroud Oil Properties used 426 barrels of cross-linked fluid with 52 percent pad and 3 percent flush, and 30,000 pounds of 12/20 sand mixed at one to nine pounds per gallon injected at 20 barrels per minute. Operators were avoiding large-volume treatments due to a fear that fractures could be induced in thick water-bearing sands above and below the coals, which would have created excess water production (Quarterly Review, 1993). Stoeckinger (2000) reports that current hydraulic fracturing practices in the Cherokee Basin in Kansas are water only, no gel, with nitrogen being popular and "slick-water down tubing."

Pam Hudson, of the Oklahoma Corporation Commission, indicated that coalbed methane extraction was beginning to grow in the Cherokee Basin in the northeastern section of Oklahoma, and more development was now centered on that region as opposed to the Arkoma Basin to the south. Ms. Hudson expected that much of the development would be focused on Washington, Nowata, and Craig Counties (Hudson, 2001).

In Missouri, there appears to be little to no coalbed methane extraction within the Cherokee Basin. David Smith, a geologist with the Missouri Geological Survey, stated that coalbed methane extraction in Missouri is essentially non-existent (Smith, 2001).

8.3.3 Forest City Basin Production Activity

The Forest City Basin was relatively unexplored in 1993, with about ten coalbed wells concentrated in Kansas' Atchison, Jefferson, Miami, Leavenworth, and Franklin Counties (Quarterly Review, 1993). The wells were hydraulically fractured with 500 to 30,000 pounds (with an average of 5000 pounds) of sand proppant. The types of fluids used during the fracturing process were not mentioned (Quarterly Review, 1993).

David Smith, believes that at one time there were some coalbed methane wells just south of Kansas City in Cass County (Smith, 2001). Sherri Stoner, of the Missouri Geological Survey, confirmed this in February 2001, and remarked that they were no longer in operation (Stoner, 2001). An Iowa Division of Natural Resources Geological Survey Bureau geologist, Mary Howes, stated that presently there was no coalbed methane production in Iowa (Howes, 2001).

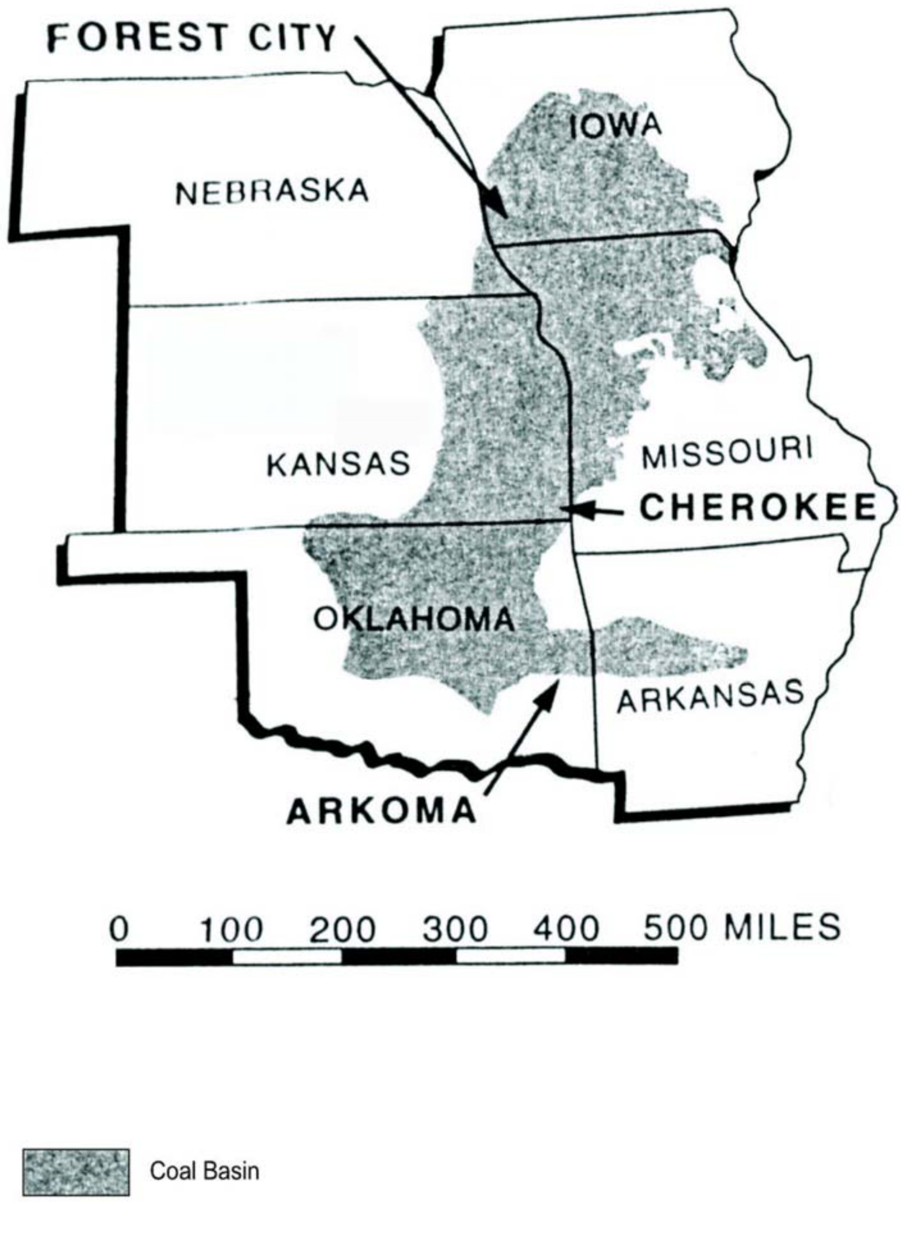
Information concerning coalbed methane production activity in Nebraska could not be found.

8.4 Summary

Based on depths to the Hartshorne Coal and the base of fresh water presented in Table A8-1, it appears that coalbed methane extraction wells in the Arkoma Basin could be coincident with potential USDWs in Arkansas, potentially allowing for impacts. Based on maps provided by the Oklahoma Corporation Commission (2001), which depicts the depths to the10,000 mg/L of TDS groundwater quality boundary in Oklahoma, the location of coalbed methane wells and USDWs would most likely not coincide in Oklahoma. This is based on depths to coals typically greater than 1,000 feet (Andrews et al., 1998) and depths to the base of the USDW typically shallower than 900 feet (Oklahoma Corporation Commission, 2001).

Table A8-2 supports the possibility that coalbed methane wells in the Cherokee Basin targeting the Cherokee Group coals in Kansas may coincide with USDWs, indicating the potential for impacts to drinking water. In Missouri, more water quality data is required prior to any determination of coalbed methane well/USDW conflict. In addition, since only a very small portion of the Cherokee Basin falls within the state, this portion of the basin needs to be delineated more precisely to see which USDWs lay within this small part of the basin. However, current levels of coalbed methane activity in Missouri are minimal.

Last, in the Forest City Basin, there appears to be little physical relationship between coalbeds that may be used for coalbed methane extraction and water supplies. However, aquifer and well information from the National Water Summary (1984) indicate that a co-location of the two could exist in Nebraska. More information would be needed to fully investigate the relationship between coalbeds and USDWs in the Forest City Basin.



Western Interior Coal Basin - Index Map of the Arkoma, Cherokee and Forest City Basins
(Quarterly Review, 1993)

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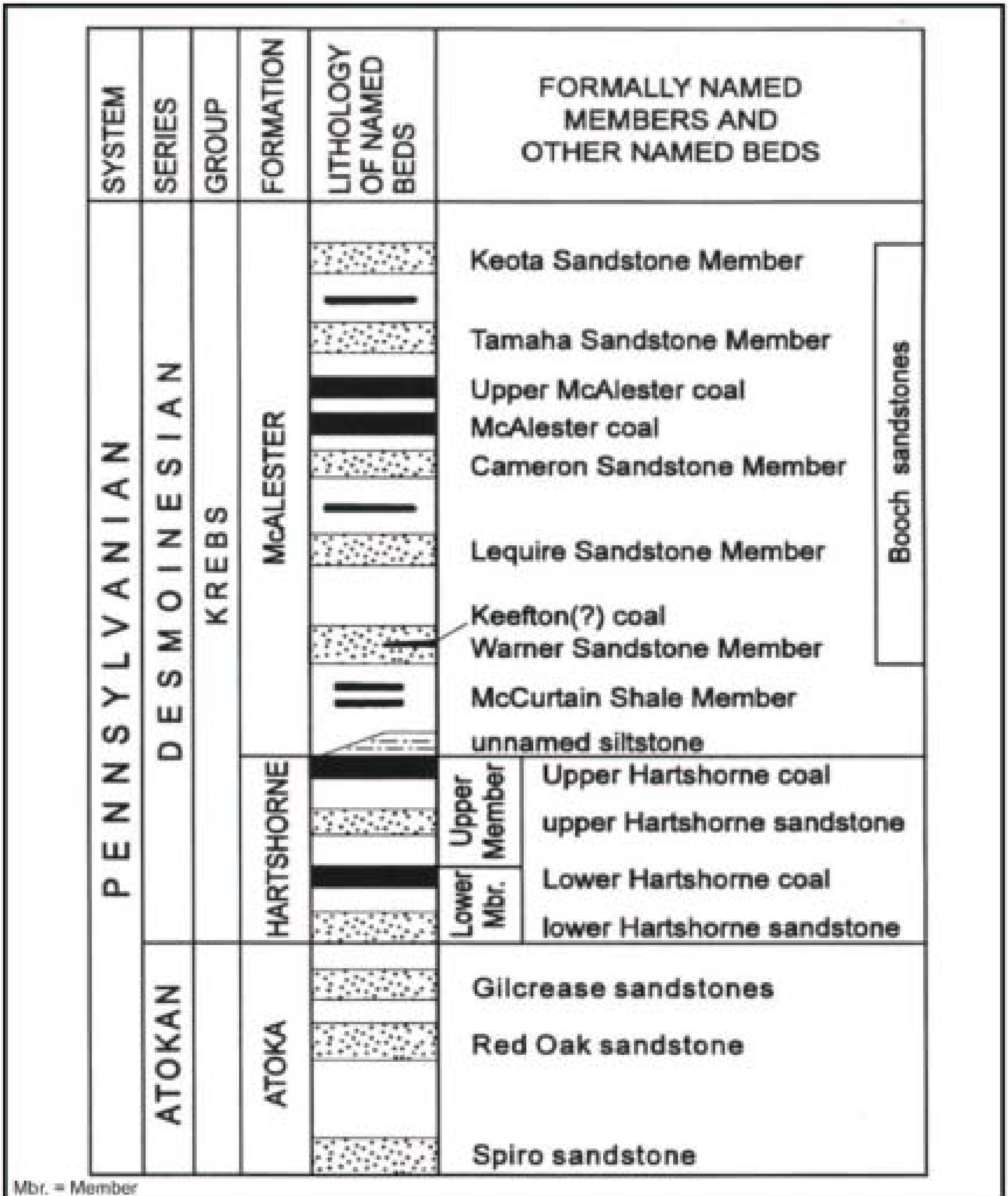
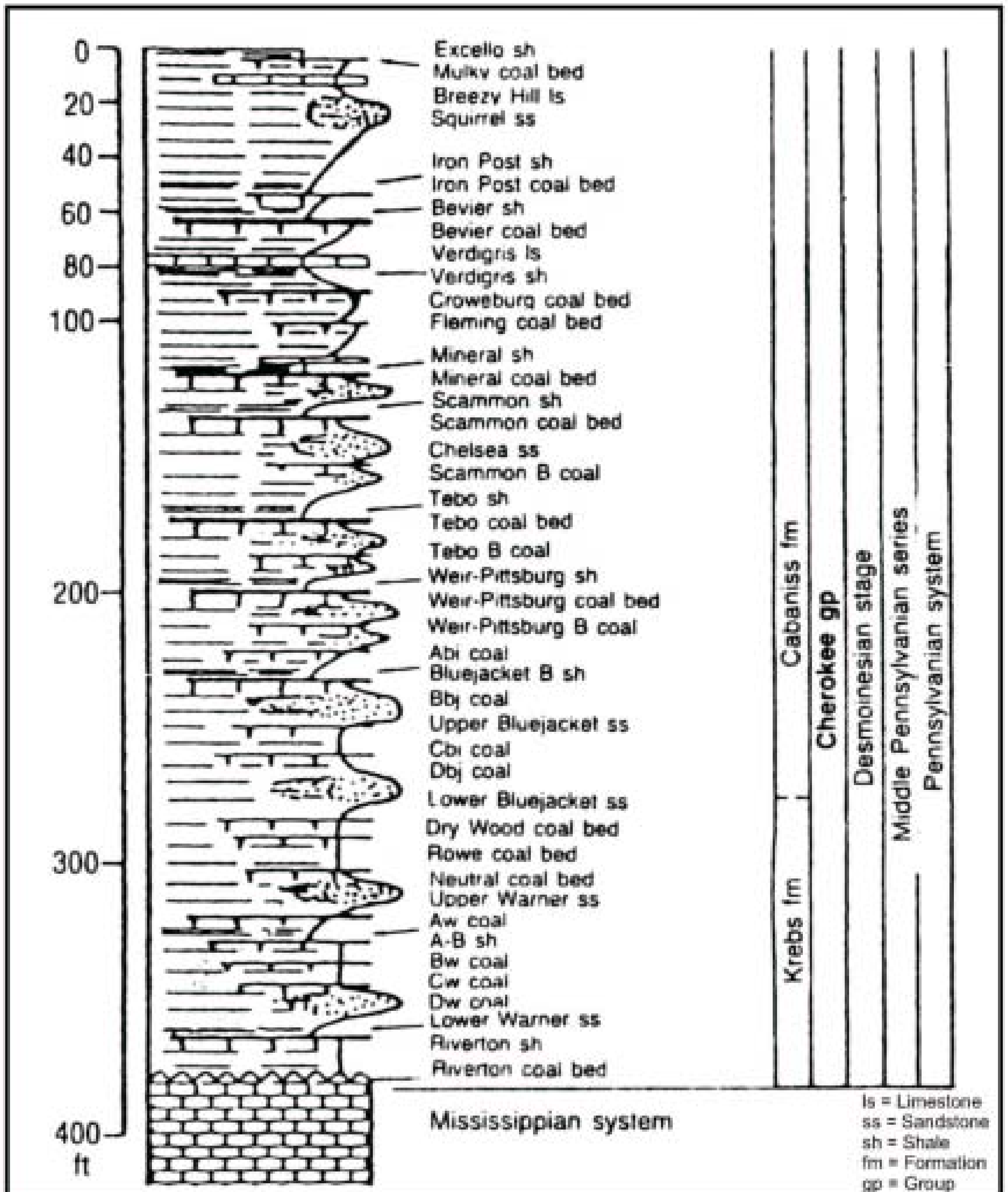
Figure A8-1



Western Interior Coal Basin - Generalized Stratigraphic Column of the Pennsylvanian System
In the Arkoma Basin (Friedman, 1982)

Figure A8-2

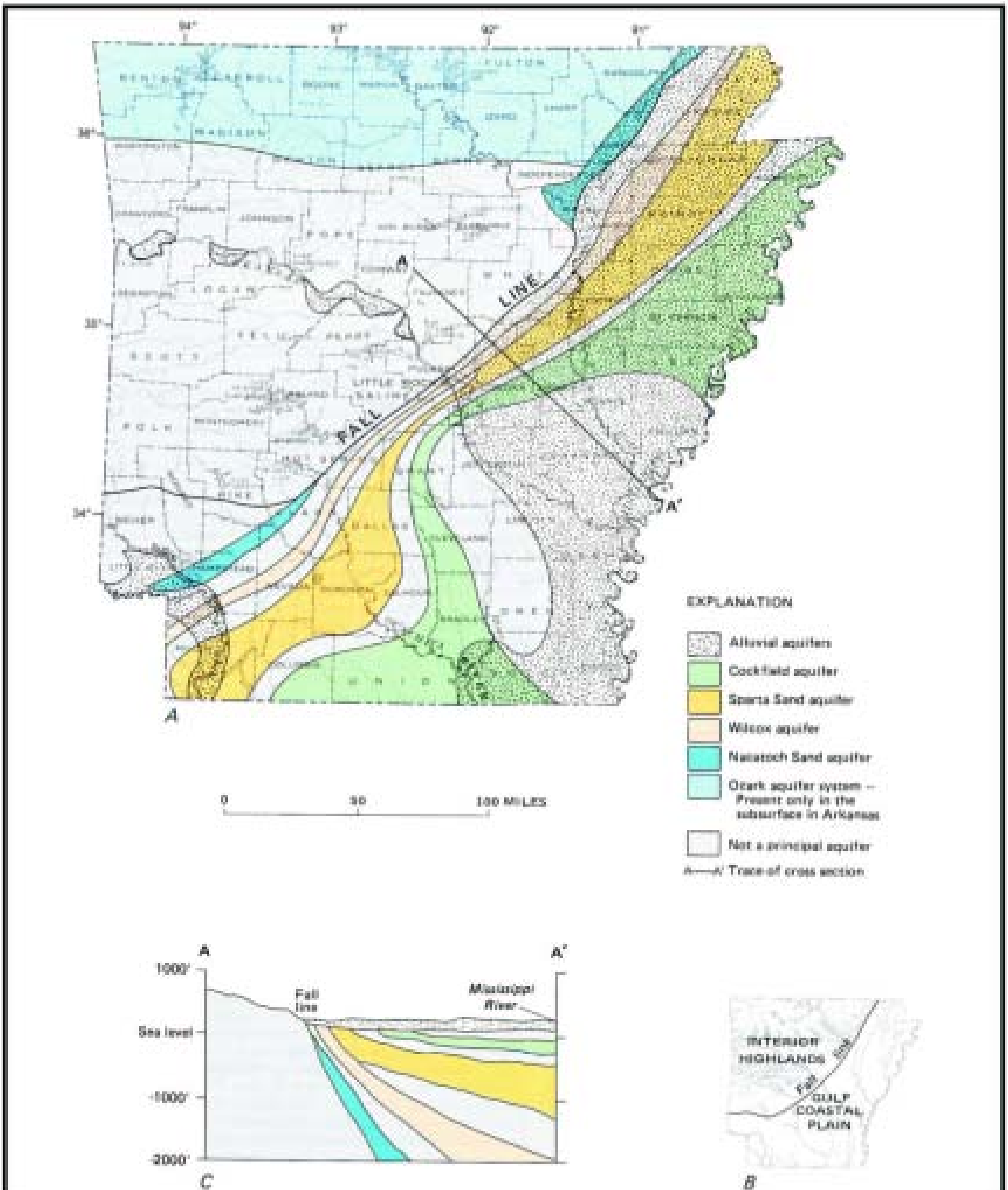


Western Interior Coal Basin - Stratigraphic Column of the Cherokee Group
In the Cherokee Basin (Tedesco, 1992)

Figure A8-3

Western Interior Coal Basin - Forest City Basin Study Area
(Showing Location of Drill Holes Discussed in Bostic et al., 1993)

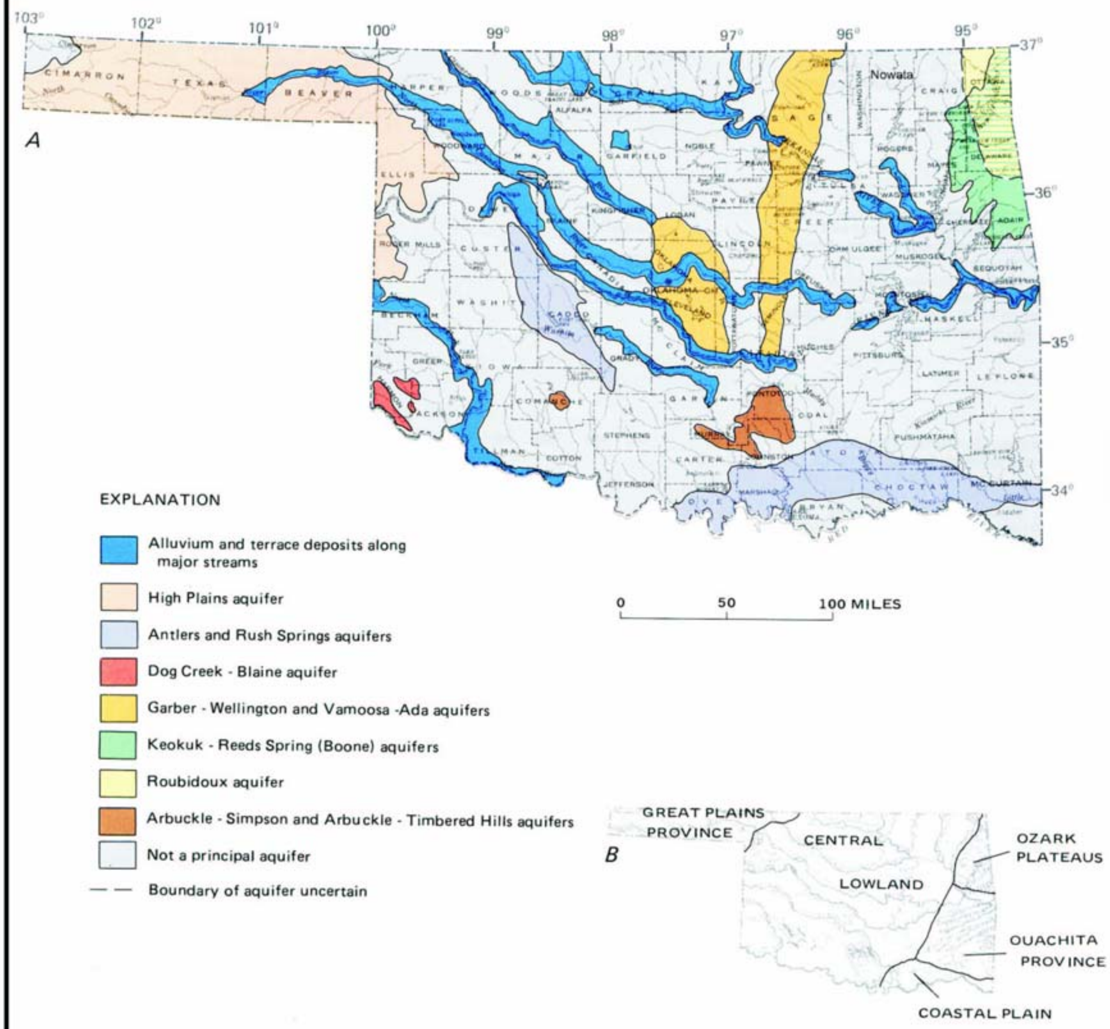
Figure A8-4



Counties, Aquifer, and Physiographic Provinces of Arkansas

(National Water Summary, 1984)

Figure A8-5



Counties, Aquifers, and Physiographic Provinces of Oklahoma

(National Water Summary, 1984)

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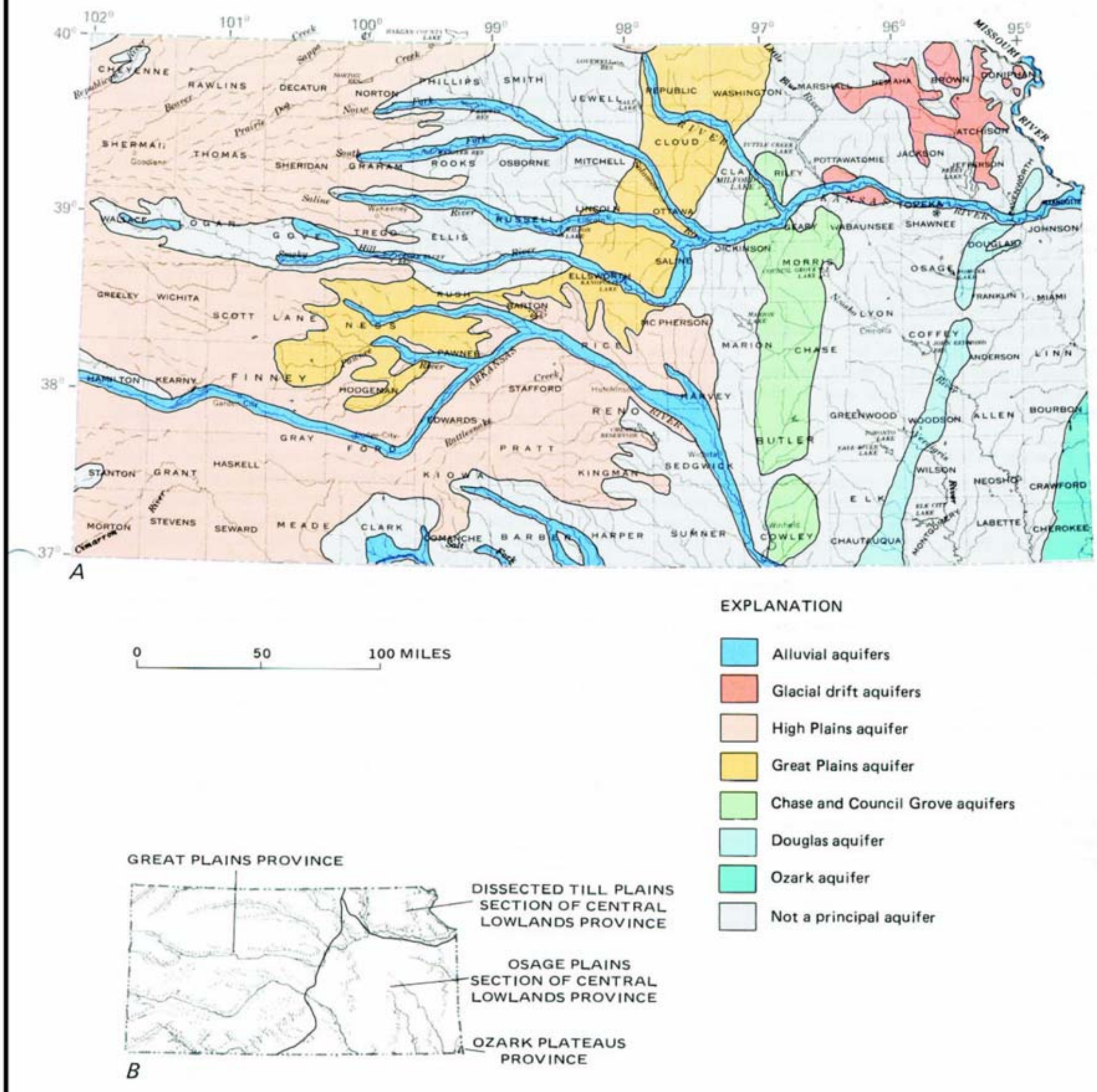
Figure A8-6



Counties, Aquifers, and Physiographic Provinces of Kansas

(National Water Summary, 1984)

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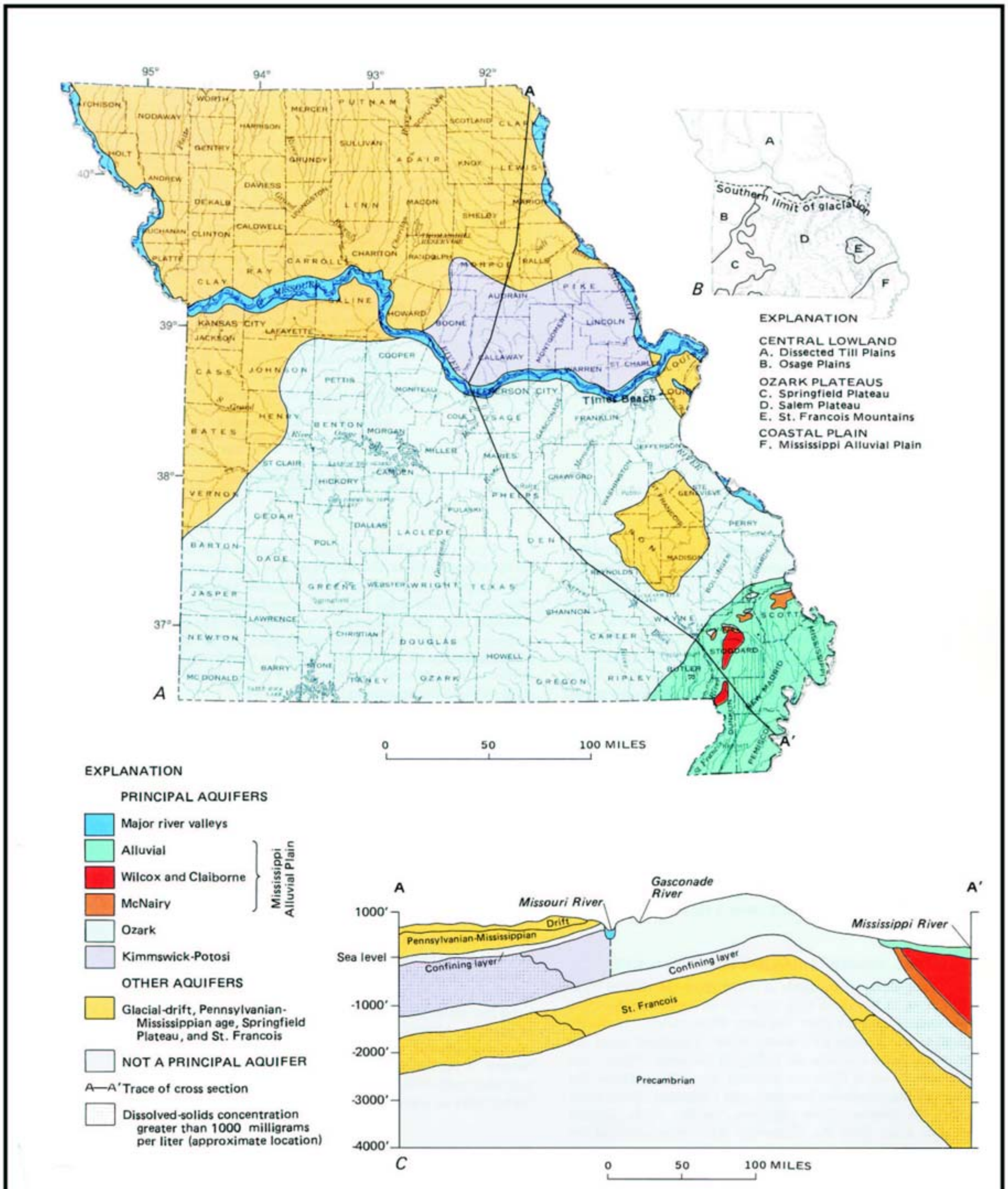
Figure A8-7



Counties, Aquifers, and Physiographic Provinces of Missouri

(National Water Summary, 1984)

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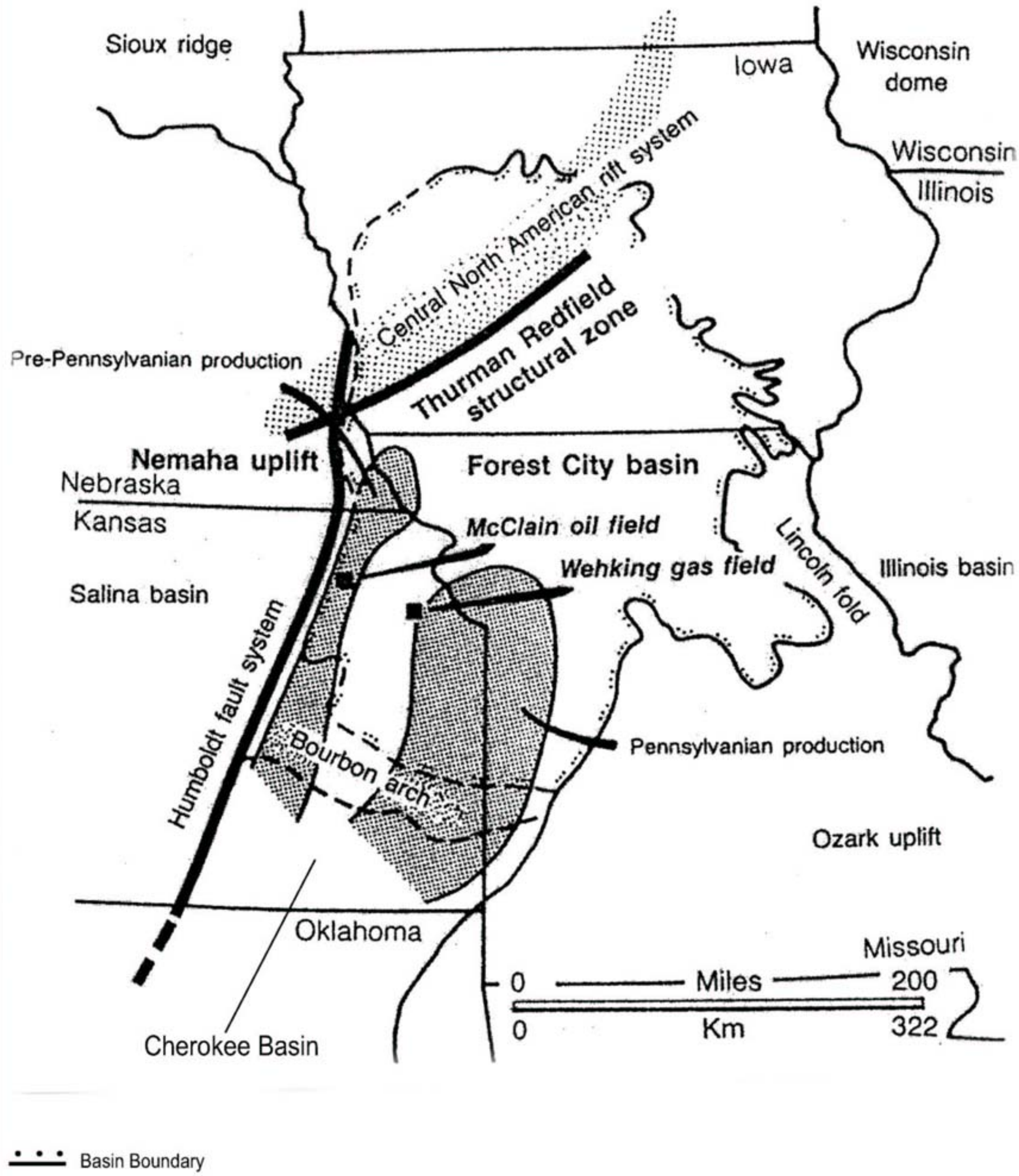
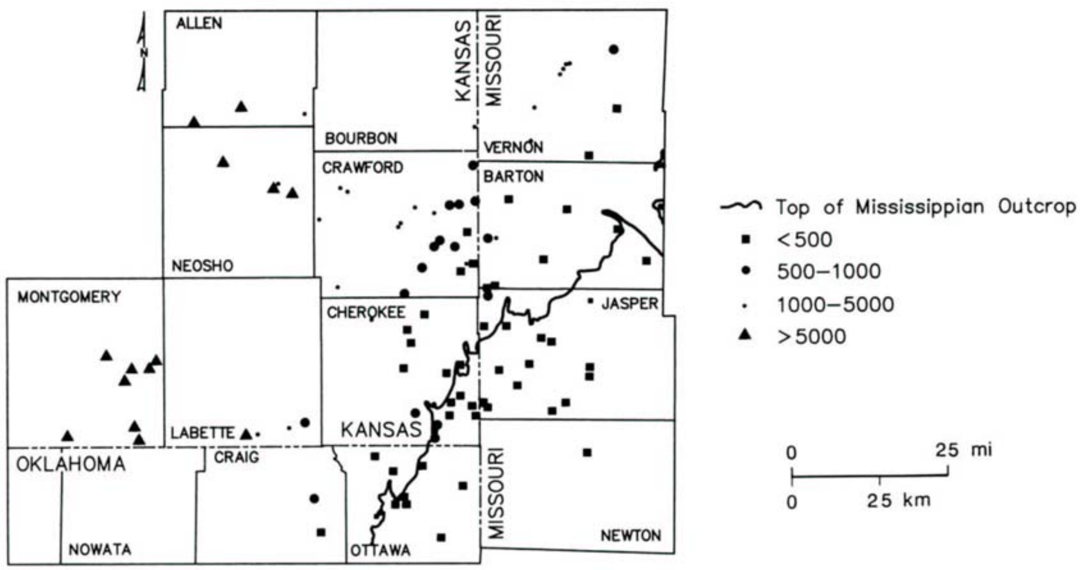
Figure A8-8



Western Interior - Detail of Forest City Basin with Detail of Cherokee Basin in Missouri (Tedesco, 1992)

5/29/02 kk 1027-WI-9.cdr | Figure A8-9



Water Quality (TDS) of Lower Paleozoic Aquifers in Kansas
(Macfarlane and Hathaway, 1987)

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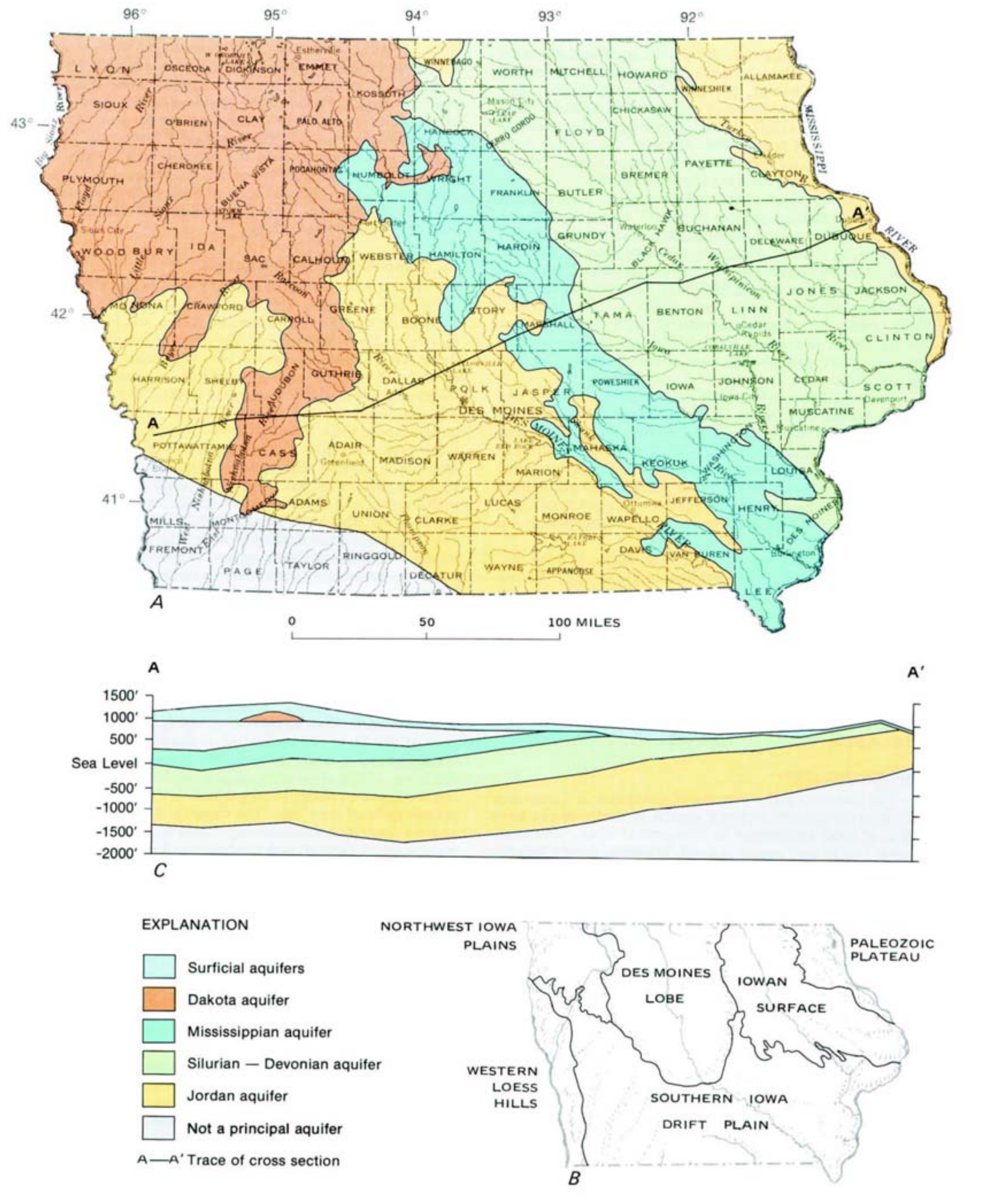
Figure A8-10

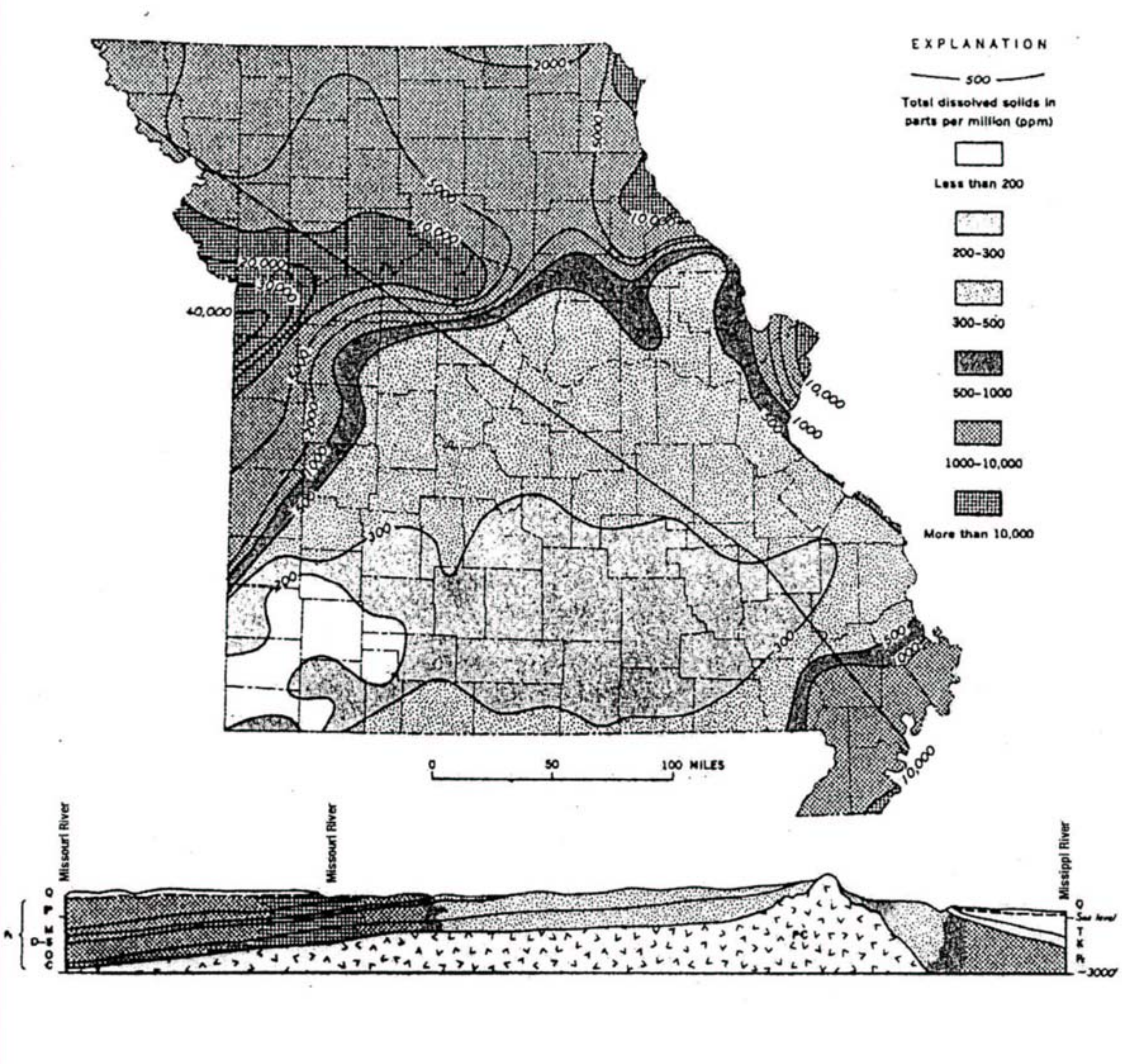


Counties, Aquifers, and Physiographic Provinces of Iowa

(National Water Summary, 1984)

5/29/02 kk 1027-WI-11.cdr

Figure A8-11

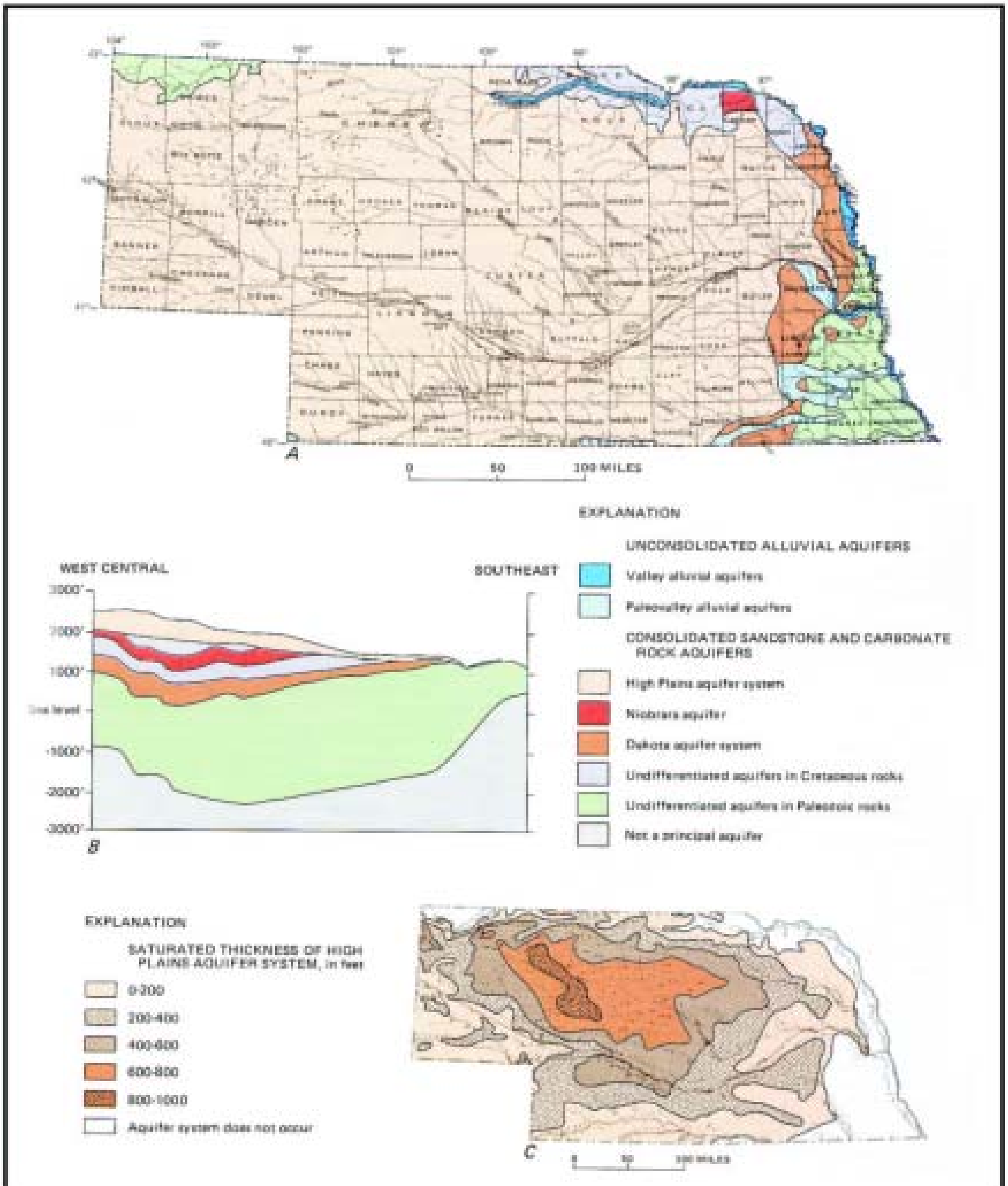


Western Interior Coal Basin - Quality of Ground water in the Palezoic Aquifers of Missouri

(Missouri Division of Geological Survey & Water Resources, 1967)

5/29/02 kk 1027-WI-12.cdr

Figure A8-12



Counties, Aquifers, and Physiographic Provinces of Nebraska

(National Water Summary, 1984)

Figure A8-13

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Attachment 9
The Raton Basin

The Raton Basin covers an area of about 2,200 square miles in southeastern Colorado and northeastern New Mexico (Figure A9-1). It is the southernmost of several major coal-bearing basins along the eastern margin of the Rocky Mountains. The basin extends 80 miles north to south and as much as 50 miles east and west (Stevens et al., 1992). It is an elongate asymmetric syncline, with 20,000 to 25,000 feet of sedimentary rock in the deepest part. Coalbed methane resources in the basin, which have been estimated at approximately 10.2 trillion cubic feet (Tcf), are contained in the upper Cretaceous Vermejo Formation and upper Cretaceous and Paleocene Raton Formation (Stevens et al., 1992). In 2000, the average gas production rate per well in the Raton Basin was close to 300,000 cubic feet per day, and annual production was 30.8 billion cubic feet (Bcf) (GTI, 2002).

9.1 Basin Geology

The Raton structural basin is an asymmetric synclinal sedimentary basin containing sedimentary rocks as old as Devonian overlying basement Precambrian rocks, with Holocene sediments at the surface. The coal occurs in the Vermejo and the Raton Formations, which overlie the Trinidad Sandstone, a basin-wide regressive marine sandstone (Figure A9-2). The Vermejo and Raton Formations consist of deltaic lower coastal plain and fluvial deposits (Flores and Pillmore, 1987). Numerous discontinuous and thin coalbeds are located in the Vermejo Formation and the Raton Formation, which overlie the Trinidad Sandstone (Figure A9-3). The top of the Trinidad Sandstone forms the lower boundary of the Raton coal basin as shown in Figure A9-1. Development of coalbed methane wells has focused on development of the Vermejo coals rather than the Raton coals because the former are thicker and more abundant. The coalbeds are of limited extent and cannot be correlated over more than a few miles.

Individual coalbeds in the Vermejo Formation range from a few inches to about 14 feet thick, and total coal thickness typically ranges from 5 to 35 feet. An isopach map of total coal thickness in the Vermejo Formation, based on 92 well logs and measured sections, was published by Stevens et al. (1992) (Figure A9-4). Total coal thickness in the Raton Formation ranges from 10 feet to greater than 140 feet, with individual seams ranging from several inches to greater than 10 feet thick. Although the Raton Formation is much thicker and contains more total coal than the Vermejo Formation, individual coal seams in the Raton are less continuous and generally thinner. Additionally, because of extensive erosion of the Raton Formation, particularly in the eastern part of the basin, much of the original coal is no longer present (Stevens et al., 1992). Between 5 and 15 individual coalbeds produce coalbed methane for wells in the basin (Hemborg, 1996).

Middle Tertiary igneous intrusions are present in the central part of the basin (Steven, 1975). Sills and dikes have invaded sediments of the basin including both the Vermejo and Raton Formations. Sills have intruded along the coal seams destroying tremendous quantities of coal (Carter, 1956).

Coal seam depth is an important variable used to estimate gas production potential. Figure A9-5 is a thickness of overburden map from Stevens et al. (1992). The map shows the depth below land surface to the midpoint depth of the coal-bearing interval, using coal thickness as a weighting factor. Overburden thickness ranges from less than 500 feet near the basin perimeter to greater than 4,100 feet in the deep northwestern part of the basin. Many of the differences in thickness of overburden can be attributed to variations in topography and are thus a consequence of erosion and not necessarily subsurface geologic structure.

Stratigraphic cross-sections constructed to illustrate the regional subsurface geologic structure and the distribution of coal seams and igneous intrusions, as well as the areal locations of these cross-sections, are shown in Figures A9-6 through A9-8. The cross-sections use the top of the Trinidad Sandstone as the horizontal datum. The Vermejo Formation has a relatively uniform thickness of about 350 feet throughout the basin. The Raton Formation varies from about 0 to 2,100 feet thick. It grades westward into and is overlain by the conglomeratic Poison Canyon Formation (Flores, 1987; Flores and Pillmore, 1987).

A study of the relationship between coal cleat orientation and the compression stresses due to tectonic forces can indicate areas likely to have increased coal seam permeability and provide increased coalbed methane yield (Stevens et al., 1992). Cleats, or small-scale fractures in the coal, are commonly oriented perpendicularly to the maximum stress. These fractures tend to expand, thereby providing greater permeability and coalbed methane yields on the axes of the anticlines, such as the Vermejo Park anticline. Wells drilled near the axis of the La Veta syncline, in contrast, did not encounter adequate permeability (Stevens et al., 1992). Initially it was thought that sills that intrude along the bedding plane of the coal seams would reduce methane production, but several operators have noted that elevated methane contents have sometimes been measured in coal seams that have been intruded by igneous rocks (Stevens et al., 1992).

9.2 Basin Hydrology and USDW Identification

Regional groundwater flow in the Raton Basin is dependent on geologic structure and topography. Regional flow is generally down-slope from west to east or southeast (Figure A9-9). In the northern part of the basin, however, flow is radial away from Spanish Peaks (Howard, 1982; Geldon, 1990). Additionally, along the eastern margin of the basin, sediments dip to the west and groundwater flow is locally down-dip to the west. While recharge occurs primarily at elevations greater than 7,500 feet, discharge is mainly through streams and by evapotranspiration in the central and eastern parts of the basin.

Principle bedrock aquifers in the basin are the Cuchara-Poison Canyon, the Raton-Vermejo-Trinidad, the Fort Hayes-Codell, the Dakota-Purgatoire, and the Entrada (Geldon, 1990) (Figure A9-3). The pressure regime in the basin is poorly understood. Under-pressured conditions, or hydraulic heads in deep bedrock aquifers that are lower than those in shallow formations, appear to exist throughout much of the basin (Howard, 1982; Geldon, 1990; Tyler et al., 1995). This hydraulic head difference suggests that the deep bedrock aquifers are not in communication with shallow formations. Meteoric circulation, however, is indicated by the regional freshness of the produced waters (Stevens et al., 1992; Tyler et al., 1995).

All of the water produced along with coalbed methane in the Raton Basin has a total dissolved solids (TDS) content of less than 10,000 milligrams per liter (mg/L) (the water quality criterion for an underground source of drinking water (USDW)), and the aquifers from which the gas is produced meet the water quality criterion for a USDW (National Water Summary, 1984). A scatter diagram of potentiometric head versus TDS from coalbed methane wells in the Raton Basin (Figure A9-10) shows little correlation between potentiometric head and water quality. More importantly, this figure shows that all of the water had less than 10,000 mg/L of TDS, nearly all had a TDS of less than 2,500 mg/L, and more than half had a TDS of less than 1,000 mg/L. Two producers used injection wells for disposal, but operating permits issued to one gas producer (Evergreen Resources, Inc.) by the Colorado Department of Public Health and Environment allowed discharge of produced water into streambeds and stock ponds, indicating that the water was not too saline for surface discharge. Hemborg (1998) suggests that the wells yielding larger quantities of groundwater might be connected to the underlying water-bearing Trinidad Sandstone.

9.3 Coalbed Methane Production Activity

Hydraulic fracturing employed for enhancement of coalbed methane production is designed to enable gas within the rock to flow more readily to an extraction well. Coalbed methane well stimulation using hydraulic fracturing techniques is a common practice in the Raton Basin. Records show that fluids used are typically gels and water with sand proppants.

Hemborg (1996) reported that the average water production from coalbed methane wells in the Raton Basin was 700 barrels per million cubic feet (Mcf), and average daily production for 42 wells in the Spanish Peak Field was 0.309 Mcf (Hemborg, 1998). Conversion of these rates from coalbed methane industry units to those commonly used for water supplies gives an average water production rate for those wells of only 6.3

gallons per minute. These rates are generally not considered sufficient for public water supply or irrigation; however, they meet the water supply volume criterion for a USDW.

Hemborg (1998) showed that in most cases water yield decreased dramatically as coalbed methane production continued over time (Figure A9-11). However, some wells exhibited increased water production as coalbed methane production continued or increased over time (Figure A9-12). Two causal factors were suggested (Hemborg, 1998) for the rise in water production:

1. Well stimulation had increased the well's zone of capture to include adjacent water-bearing sills or sandstones that were hydraulically connected to recharge areas; or

2. Well stimulation had created a connection between the coal seams and the underlying water-bearing Trinidad Sandstone.

The Trinidad Sandstone is a bedrock aquifer confined by the Pierre Shale below and the shales and siltstones of the Vermejo Formation above (Figure A9-2). The Trinidad Sandstone exhibits low vertical and horizontal permeabilities of 0.186 and 0.109 meters per day, respectively, as reported by Howard (1982) in Stevens et al. (1992). One gas company reported that lower water production and improved gas production were achieved by avoiding known water-bearing horizons and by selectively completing the coal zones (Quarterly Review, 1993).

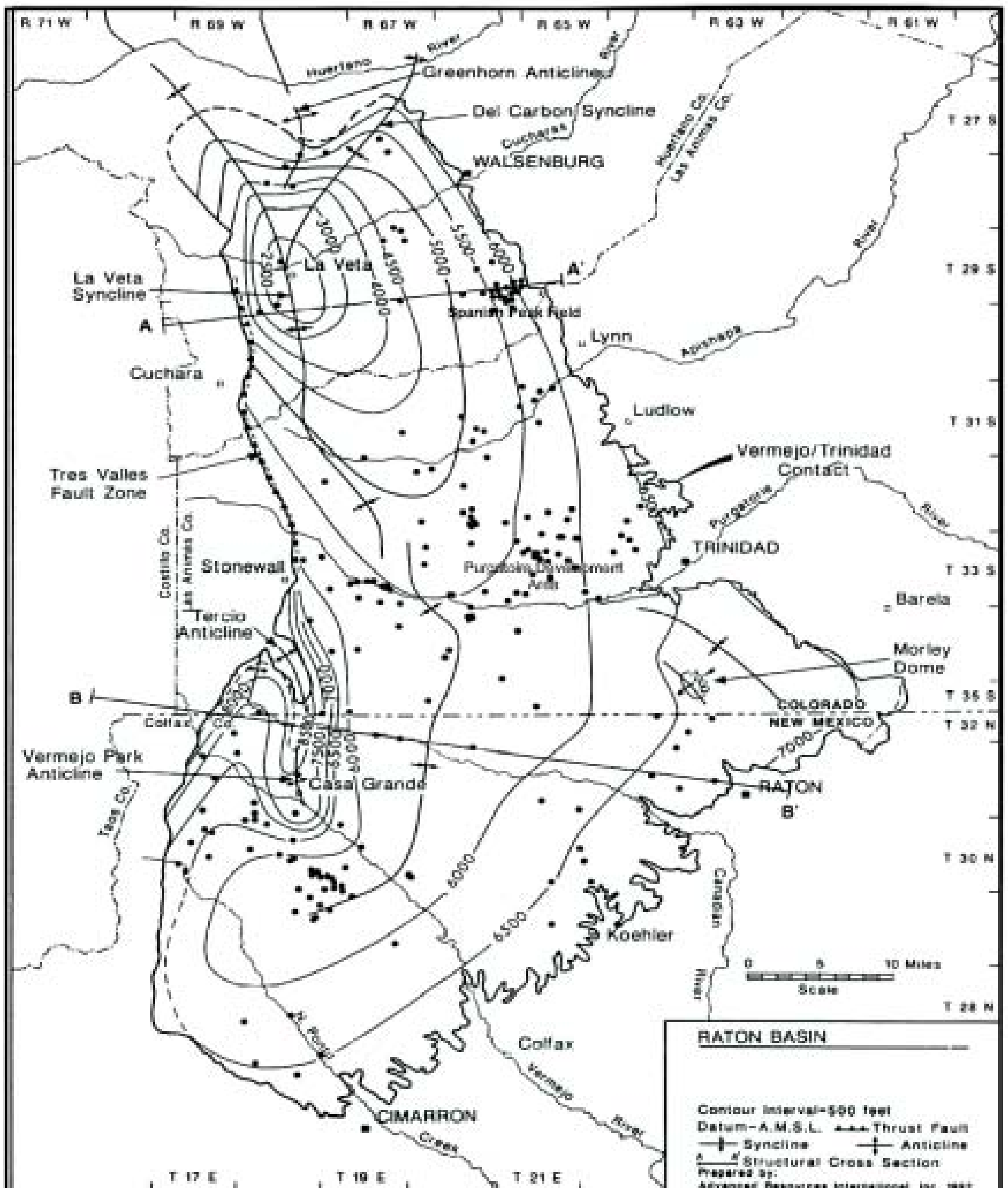
In-place coalbed methane resources in the Vermejo and Raton Formations were estimated by Stevens (1992) to be between 8.4 and 12.1 Tcf with a mean estimate of 10.2 Tcf. As of 1992, 114 coalbed methane exploration wells had been drilled in the basin (Quarterly Review, 1993). Soon after the Picketwire Lateral was constructed to convey gas from the fields to Trinidad and then to markets, gas well development in the basin increased significantly. The Purgatoire River Valley (Figure A9-1), which had been identified as having the highest coalbed methane potential in the basin, up to 8 Bcf per square mile (Stevens et al., 1992), became the focus of development. The Purgatoire Valley area was considered favorable for development because total coal thickness ranges from 5 to over 15 feet, drilling depths are shallow and coalbed methane content is high. The New Mexico portion of the basin was estimated to have methane resources ranging from 4 Bcf per square mile in the southern and eastern margins of the basin to more than 8 Bcf per square mile in the area south of the Vermejo Park anticline. Coal seams in the Vermejo Park area (Figure A9-1) are relatively thick, but shallow and of low rank, making estimates of coalbed methane content relatively low (Stevens et al., 1992).

The Spanish Peak Field, in the Purgatoire River development area in Las Animas County, Colorado (Figure A9-1), had 53 active wells in December 1996. Plans had been announced by Evergreen Resources, Inc. to drill and complete an additional 40 wells in 1997 (Hemborg, 1998). In 1996, the Purgatoire development area was projected to be capable of producing 122-137 Mcf per day in 3 to 4 years (Figure A9-1) (Hemborg, 1996). Total coalbed methane production within the Raton Basin was 30.8 Bcf per year in 2000 (GTI, 2002).

Methane production wells have generally been completed with 5.5-inch (outer diameter) casing with two to eight perforations per foot through the casing at the depths of the coal seams. The coal seams are stimulated with hydraulic fracturing treatments of sand and gelled-water, but detailed information on the nature, volumes, and use of hydraulic fracturing fluids in gas well development in this basin are not readily available. Water and gels with 10/40-mesh sand proppant seem to be the fluids of choice for fracturing practices in the Raton Basin. Stevens et al. (1992) report that multiple zones in one well are typically developed with 200,000 pounds of 10/20 or 20/40-mesh sand with 100,000 gallons of cross-linked gel per well. In one series of tests, wells were hydraulically fractured with 283,000 to 532,000 pounds of 12/20 and 20/40-mesh sand as proppant and 110,000 to 769,000 barrels of water or gel. The wells were fractured in two stages, one for a 25-foot thick upper zone and another for a 75-foot thick lower zone (Quarterly Review, 1993). Relatively high rates of water flow in these wells may be the result of fractures penetrating sandstones as well as coal seams. Another set of tests led a different methane producer to conclude that high water production was the consequence of induced fractures that intercept water-bearing sandstone and intrusive rocks. While operators initially assumed that large hydraulic fracture stimulations were necessary to link the thin and widely-spaced coal seams, it was found that such fracturing increased unwanted water production from associated sandstones, sills and water-bearing faults (Quarterly Review, 1993).

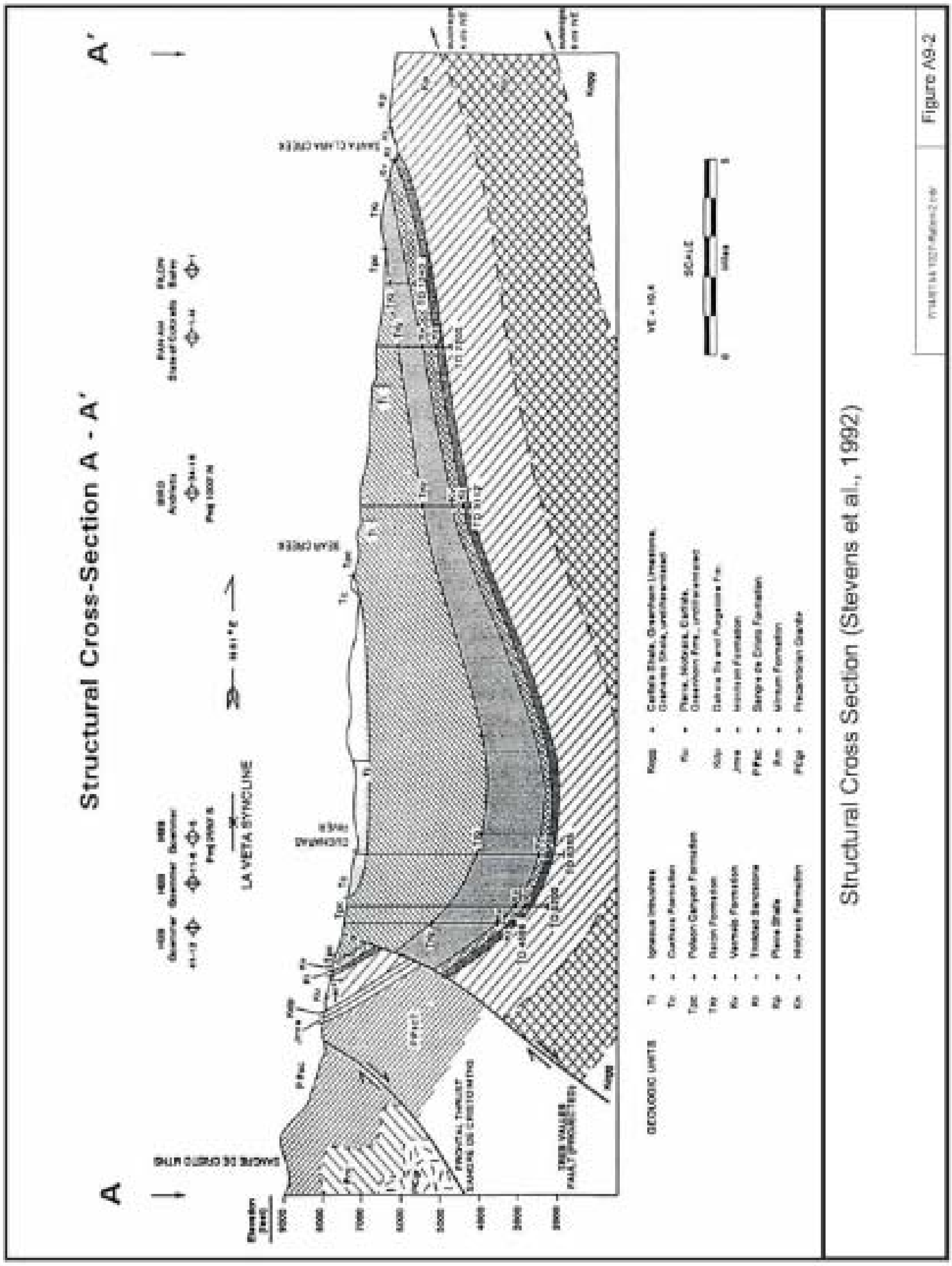
9.4 Summary

There are two major coal formations in the Raton Basin, the Vermejo Formation and the Raton Formation. The Vermejo coals range in thickness from 5 to 35 feet while the Raton coal layers range from 10 to over 140 feet thick. The coal seams of the Vermejo and Raton Formations, developed for methane production, also contain water that meets the water quality criteria for a USDW; therefore, it can be assumed that the Raton Basin coals are located within a USDW. The Cuchara-Poison Canyon, Fort Hayes-Codell, Dakota-Purgatoire, Entrada and Trinidad Sandstone and other sandstone beds within the Vermejo and Raton Formations, as well as intrusive dikes and sills, also contain water of sufficient quality to meet the USDW water quality criteria. Hydraulic fracturing may create connections to the Trinidad Sandstone, as shown by increases in water withdrawal from production wells over time. On the other hand, hydraulic connections to other adjacent water-bearing formations may also account for the increase in water production.



Structure Contour Map On Top Trinidad Sandstone (Stevens et al., 1992)

Figure A9-1

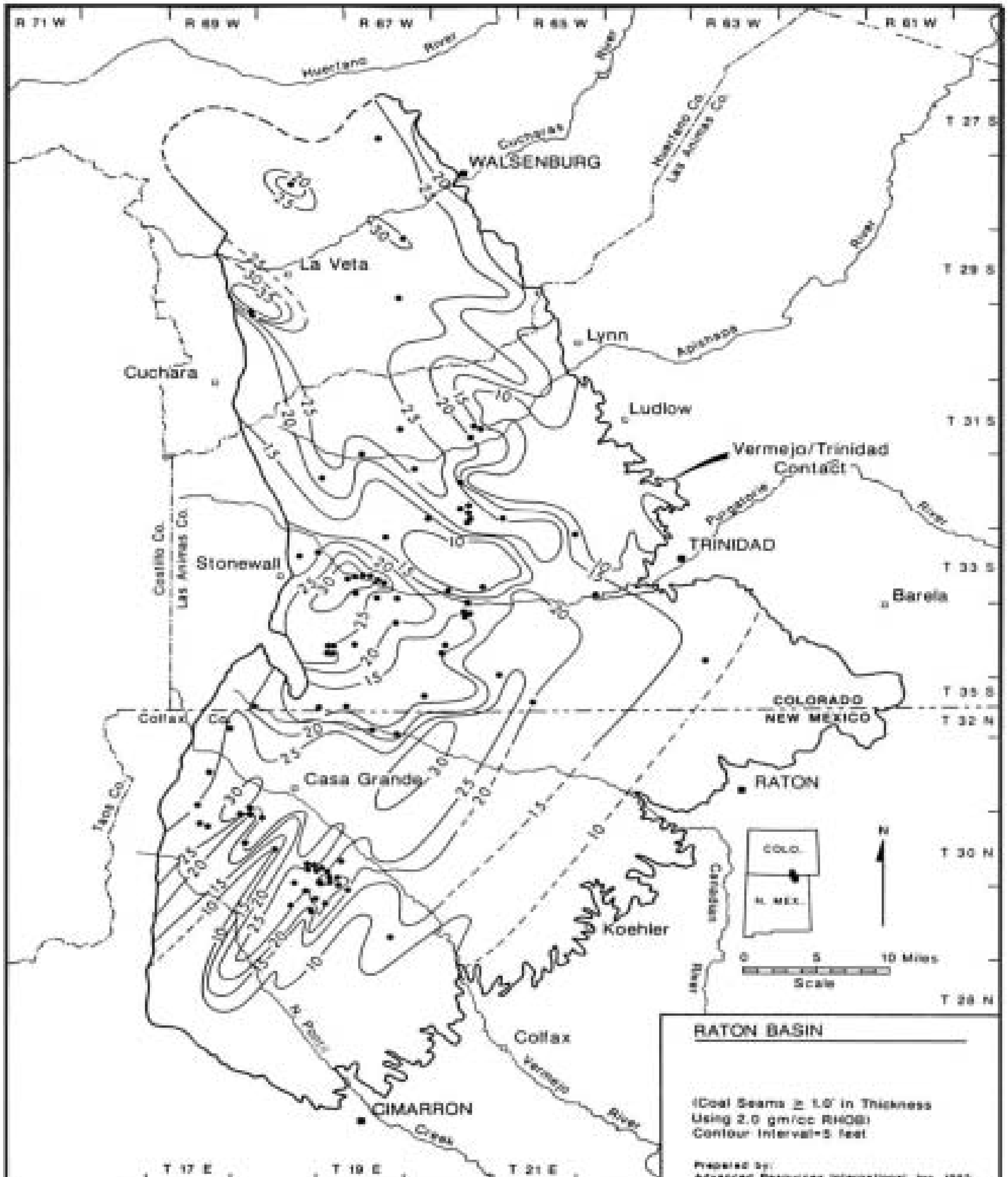


Structural Cross Section (Stevens et al., 1992)

ERA	PERIOD / EPOCH	FORMATION	THICKNESS (FT)	LITHOLOGY
CENOZOIC	Recent		0—30	Alluvium, basalt flows
CENOZOIC	Miocene	Devils Hole Formation	25–1,300	Light-gray conglomeratic tuff and conglomerate
CENOZOIC	Oligocene	Farisita Formation	0–1,200	Buff conglomerate and sandstone
CENOZOIC	Eocene	Huerfano Formation	0–2,000	Variegated maroon shale and red, gray, and tan claystone
CENOZOIC	Eocene	Cuchara Formation	0–5,000	Red, pink, and white sandstone, and red, gray, and tan claystone
CENOZOIC	Paleocene	Poison Canyon Formation	0–2,500	Buff arkosic conglomerate and sandstone, yellow siltstone, and shale
CENOZOIC / MESOZOIC	Paleocene / Upper Cretaceous	Raton Formation	0–2,075	Light-gray to buff sandstone, dark-gray siltstone, shale, and coal; conglomerate at base
MESOZOIC	Upper Cretaceous	Vermejo Formation	0–360	Dark-gray silty and coaly shale, buff to gray carbonaceous siltstone, and sandstone beds; coal
MESOZOIC	Upper Cretaceous	Trinidad Sandstone	0–255	Light-gray to buff sandstone
MESOZOIC	Upper Cretaceous	Pierre Shale	1,300–2,900	Dark-gray fissile shale and siltstone
MESOZOIC	Upper Cretaceous	Niobrara Group: Smokey Hill Marl	560–850	Yellow chalk, marine gray shale and thin white limestone; and light-gray limestone at base
MESOZOIC	Upper Cretaceous	Niobrara Group: Fort Hayes Limestone	0–55	
MESOZOIC	Upper Cretaceous	Benton Group: Codell Sandstone	0–30	Brownish sandstone, dark-gray shale, gray limestone and gray shale
MESOZOIC	Upper Cretaceous	Benton Group: Carlile Shale	165–225	
MESOZOIC	Upper Cretaceous	Benton Group: Greenhorn Limestone	30–80	
MESOZOIC	Upper Cretaceous	Benton Group: Graneros Shale	185–400	
MESOZOIC	Lower Cretaceous	Dakota Sandstone	100–200	Buff sandstone, buff conglomerate sandstone, and dark-gray shale
MESOZOIC	Lower Cretaceous	Purgatoire Formation	100–150	
MESOZOIC	Jurassic	Morrison Formation	150–400	Variegated maroon shale, gray limestone, red siltstone, gypsum, and gray sandstone
MESOZOIC	Jurassic	Ralston Creek Formation	30–100	
MESOZOIC	Jurassic	Entrada Sandstone	40–100	
MESOZOIC	Triassic	Dockum Group	0–1,200	Red sandstone, calcareous shales, and thin limestones
PALEOZOIC UNDIVIDED			5,000–10,000	Variegated shales, arkose, conglomerates, and thin marine limestone

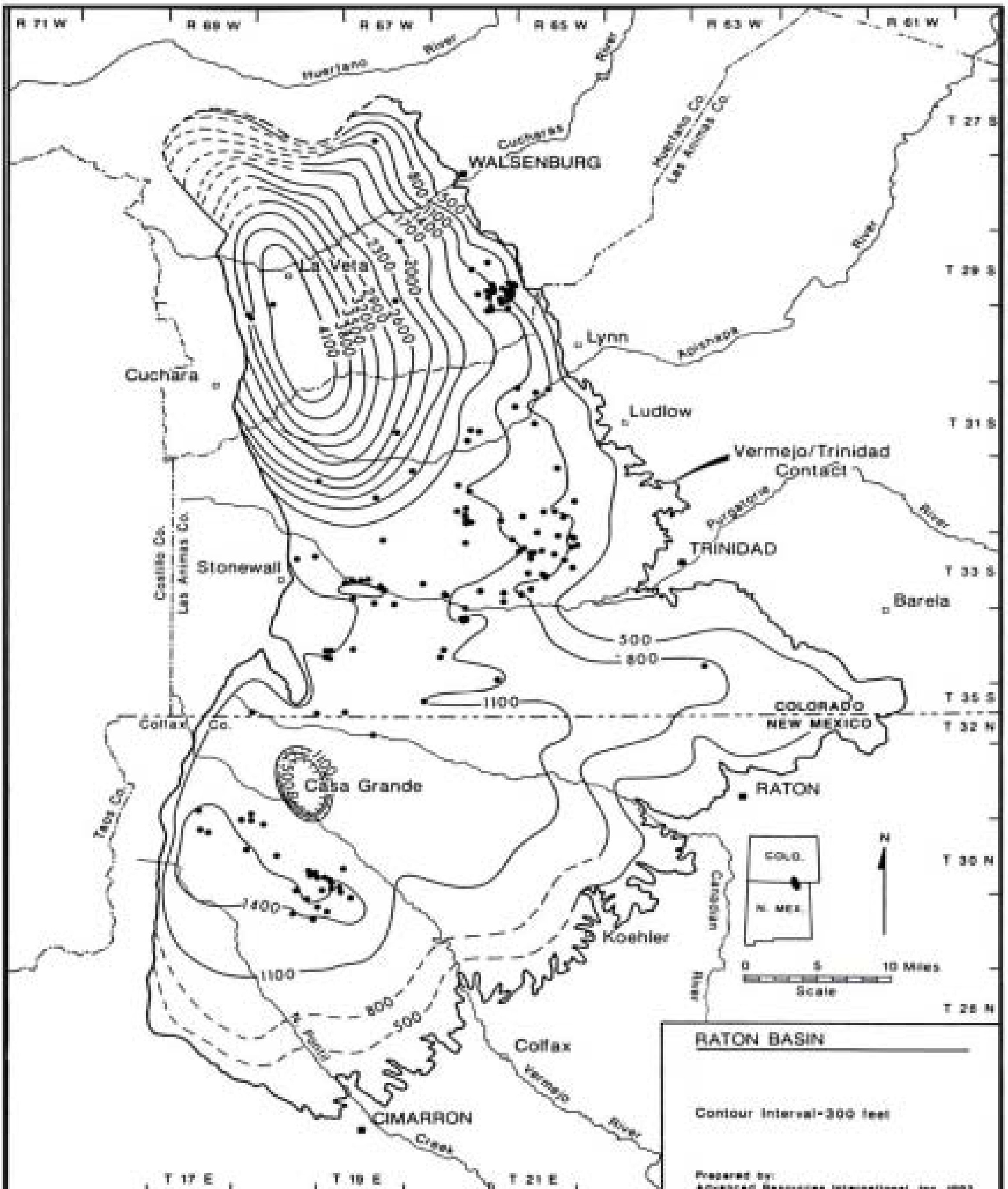
Generalized Stratigraphy of Cenozoic and Mesozoic Units (Hemborg, 1998)

Figure A9-3



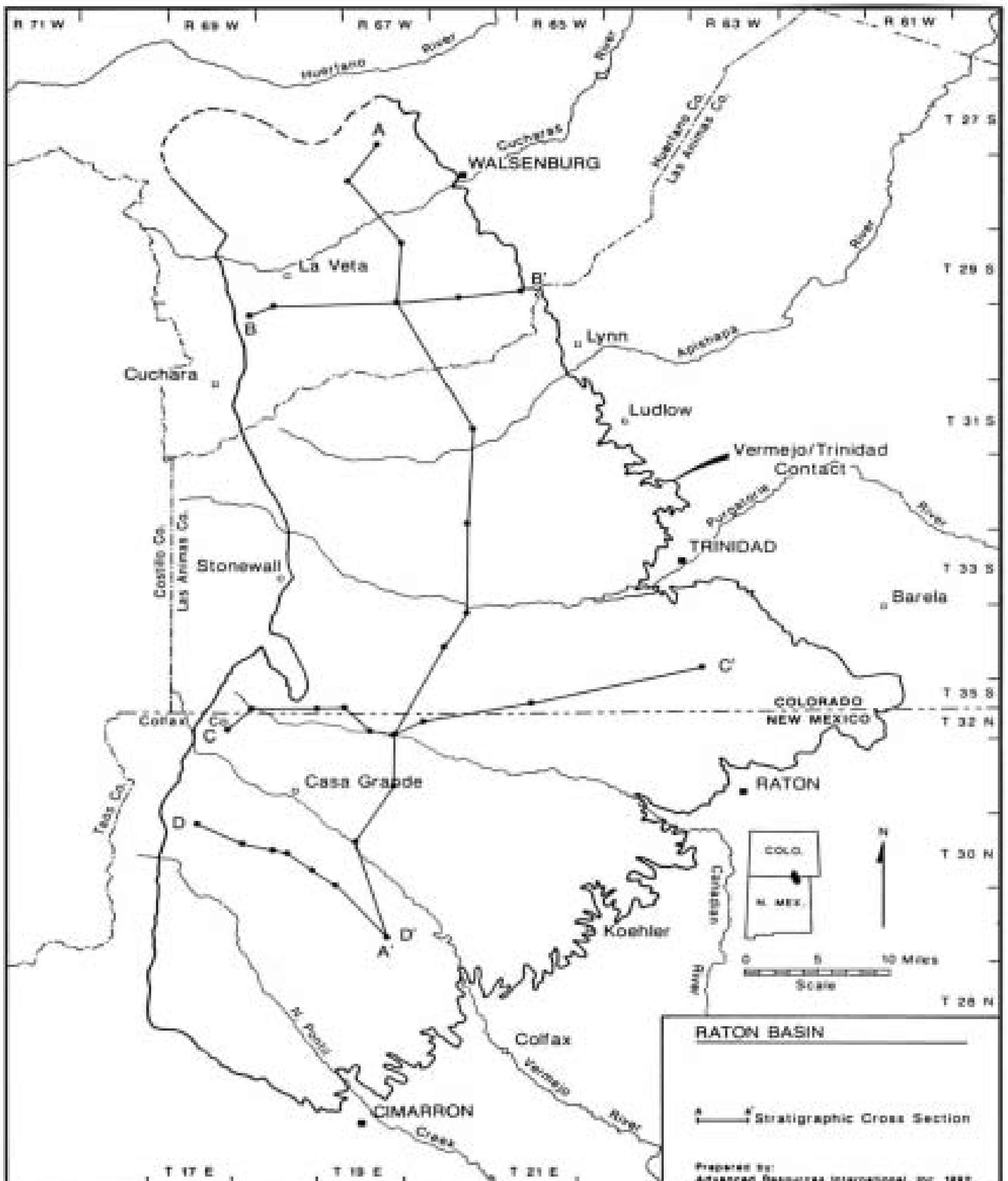
Vermejo Formation - Total Coal Isopach (Stevens et al., 1992)

Figure A9-4



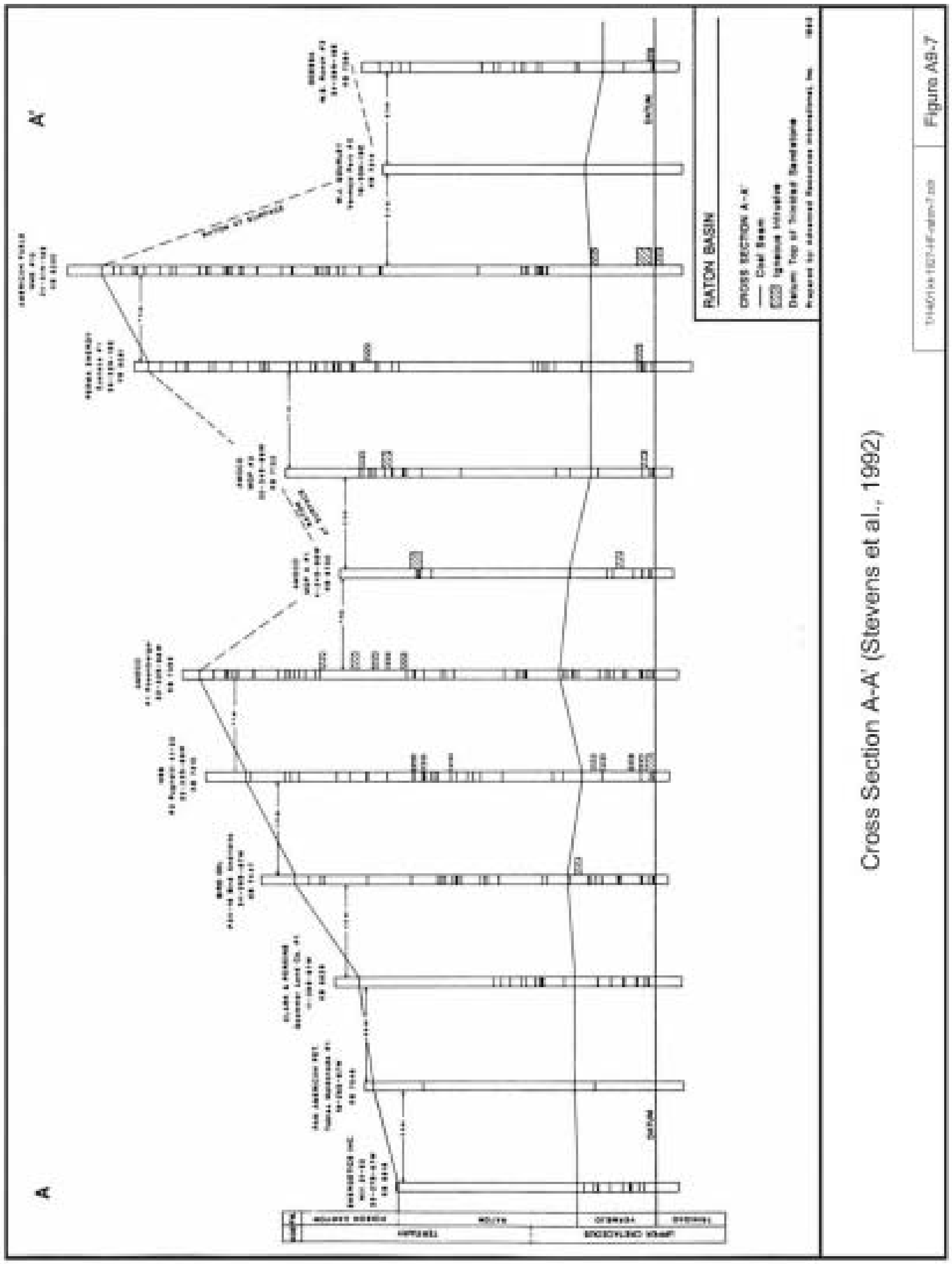
Overburden to Coal Interval (Stevens et al., 1992)

Figure A9-5

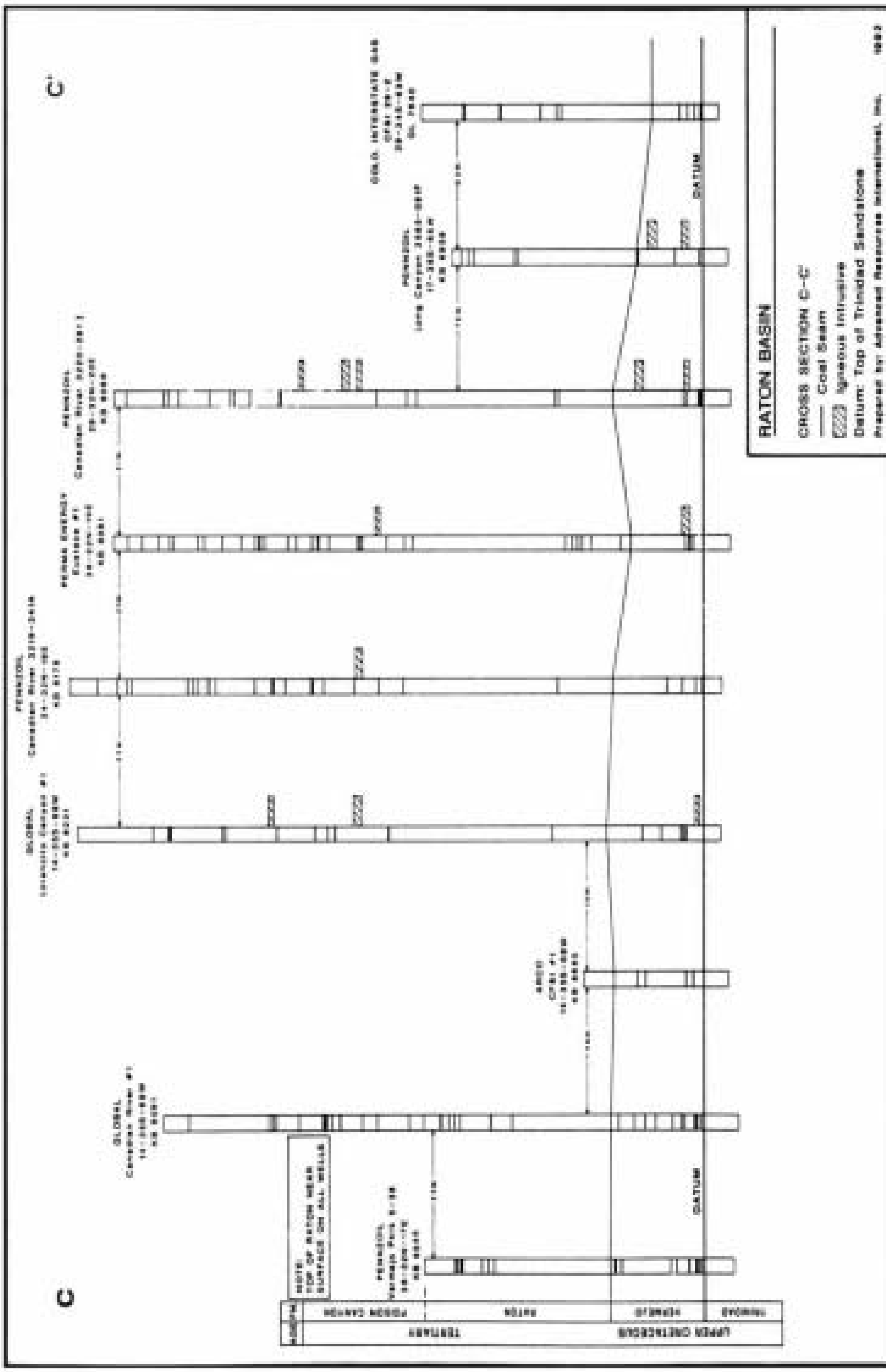


Location of Stratigraphic Cross Sections (Stevens et al., 1992)

Figure A9-6

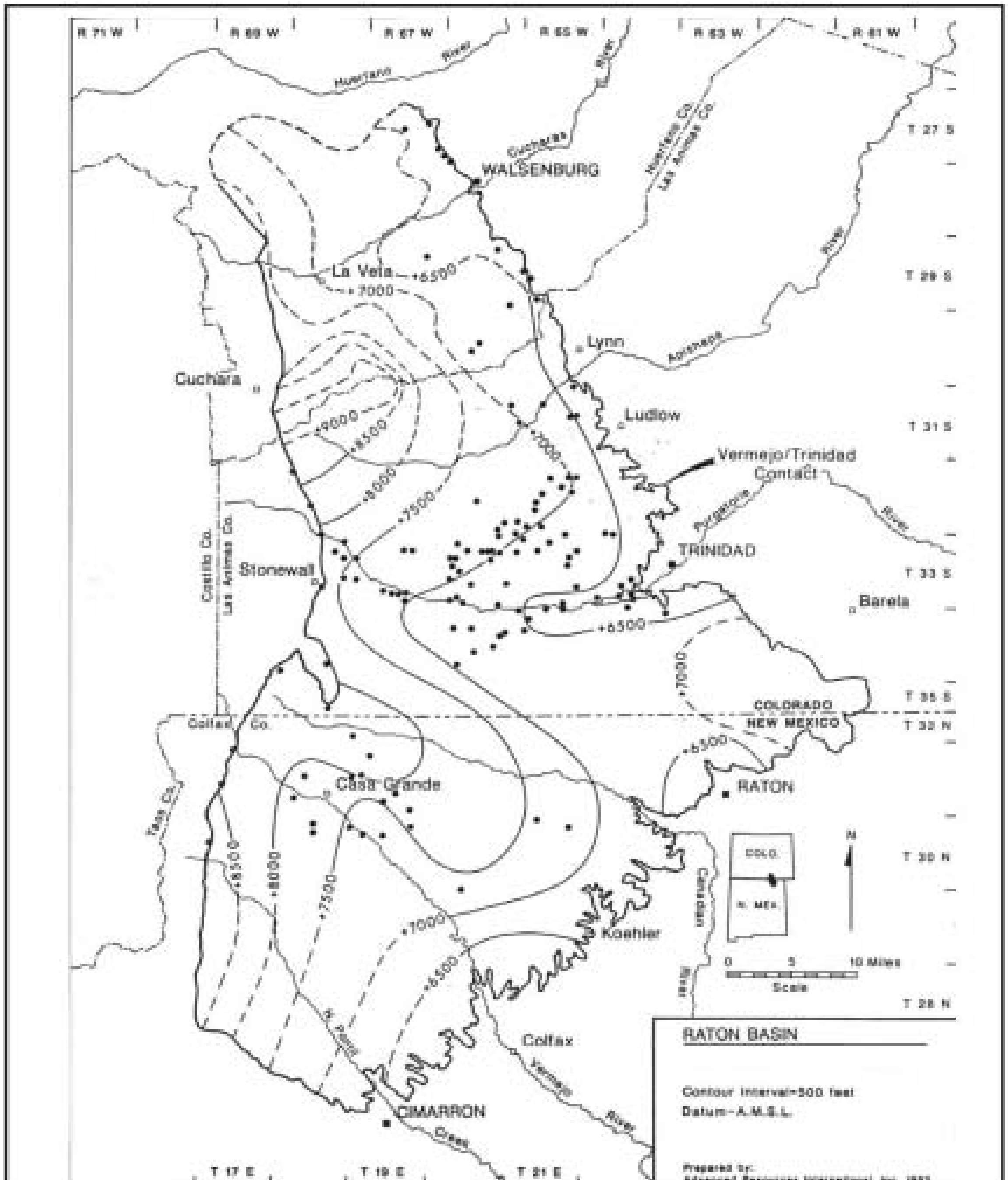


Cross Section A-A' (Stevens et al., 1992)



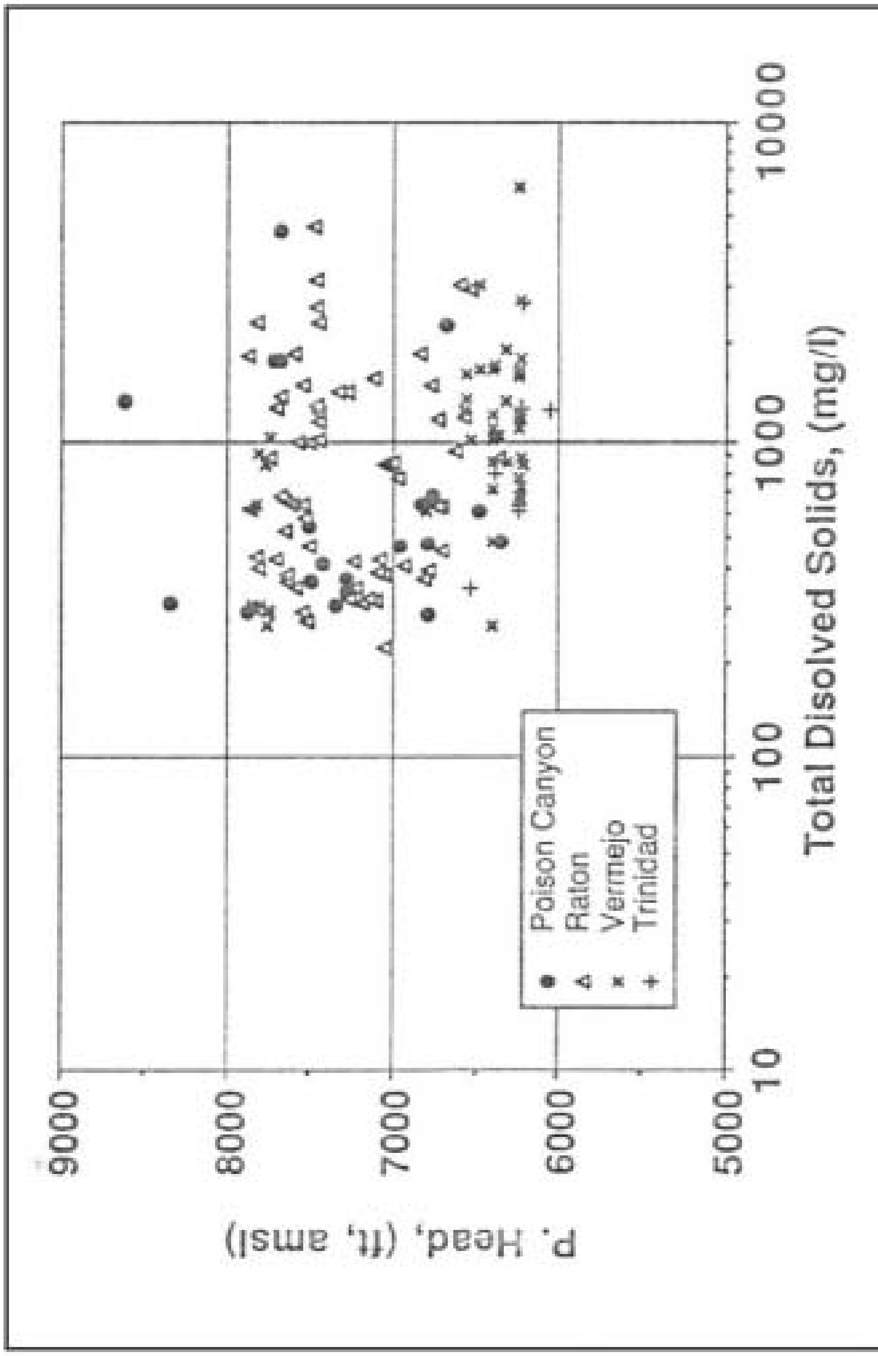
Cross Section C-C' (Stevens et al., 1992)

Figure A9-6



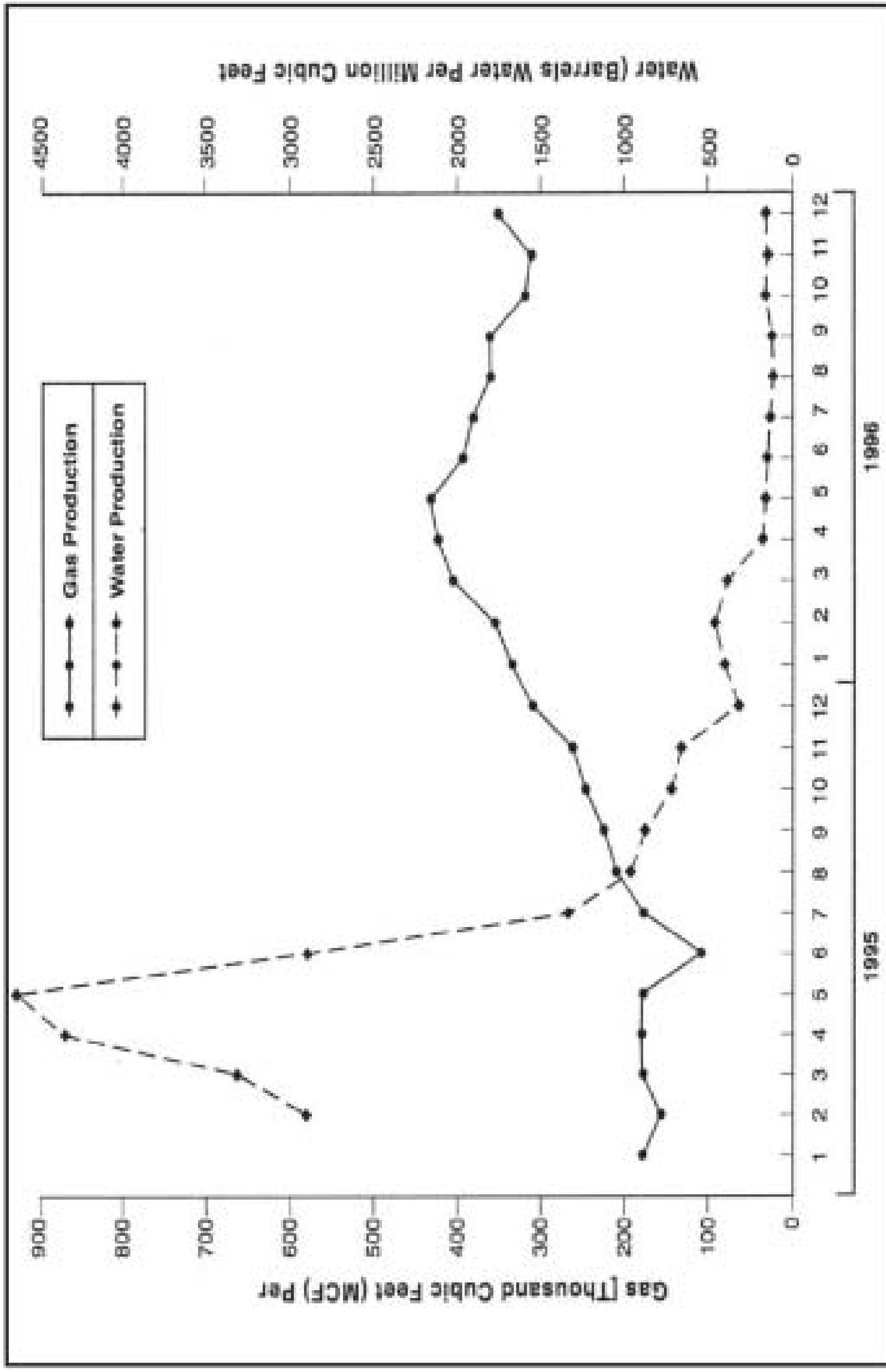
Potentiometric Surface Map for Raton Basin (Oldaker et al., 1993)

Figure A9-9



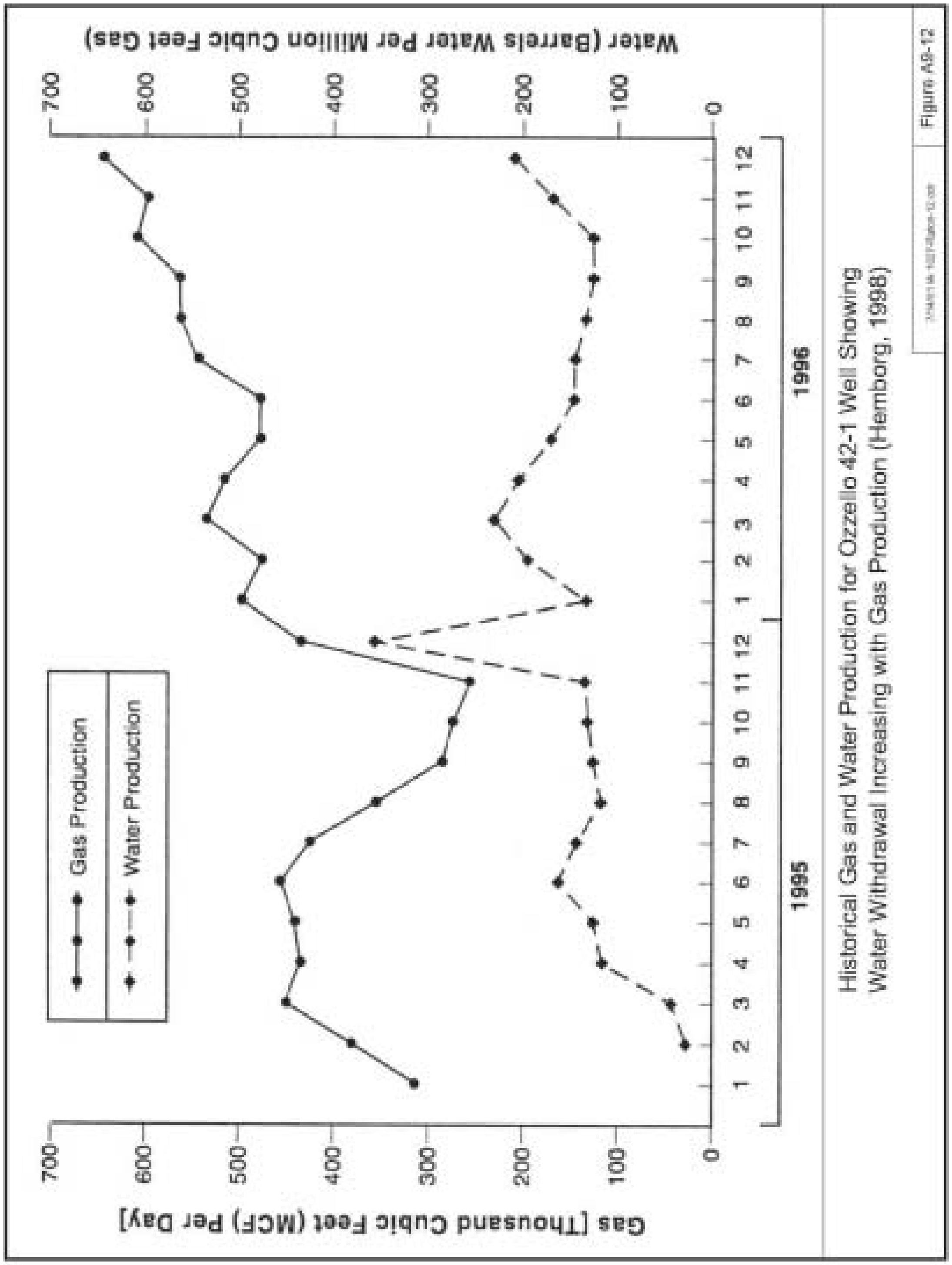
Relationship Between Gas Content and Depth Below Pontentiometric Surface for Two Groups of Coal Rank (Oldaker et al., 1993)

Figure A9-10



Historical Gas and Water Production for Typical Well Showing
How Water Withdrawal Decreases and Methane Production Increases (Hemborg, 1998)

Figure A9-11



Historical Gas and Water Production for Ozzello 42-1 Well Showing Water Withdrawal Increasing with Gas Production (Hemborg, 1998)

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