

Water Management Practices Used by Fayetteville Shale Gas Producers

prepared for
U.S. Department of Energy, Office of Fossil Energy,
National Energy Technology Laboratory

prepared by
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Environmental Science Division, Argonne National Laboratory

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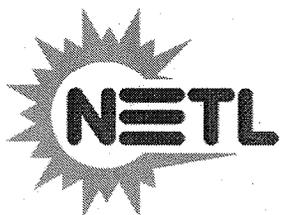
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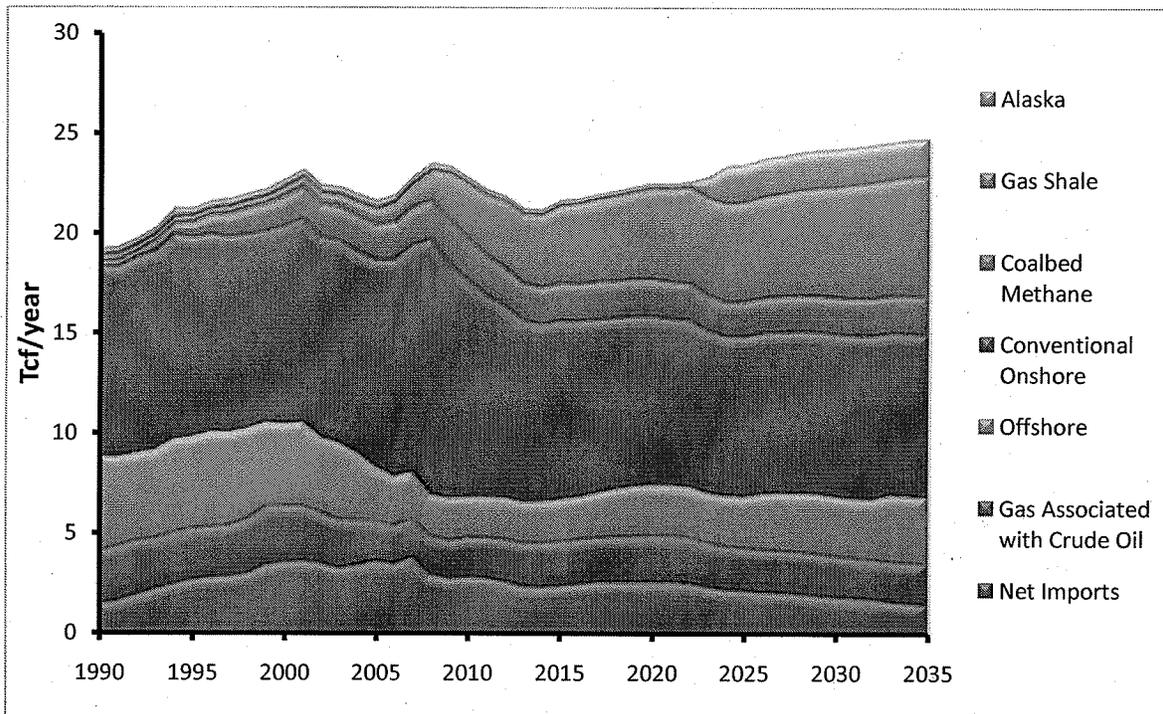
Chapter 1 – Introduction

Shale Gas

Natural gas is an important energy source for the United States. Shale formations represent a growing source of natural gas for the nation and are among the busiest oil and gas plays in the country. As an indication of their importance, in less than one year's time, the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA) dramatically increased its estimate of the proportion of future domestic gas production that is likely to come from shale formations.

Figure 1 shows a May 2010 EIA projection of the source of natural gas supplies through 2035. Shale gas supplies were anticipated to play an increasingly important role, increasing from 10% in 2009 to about 24% in 2035.

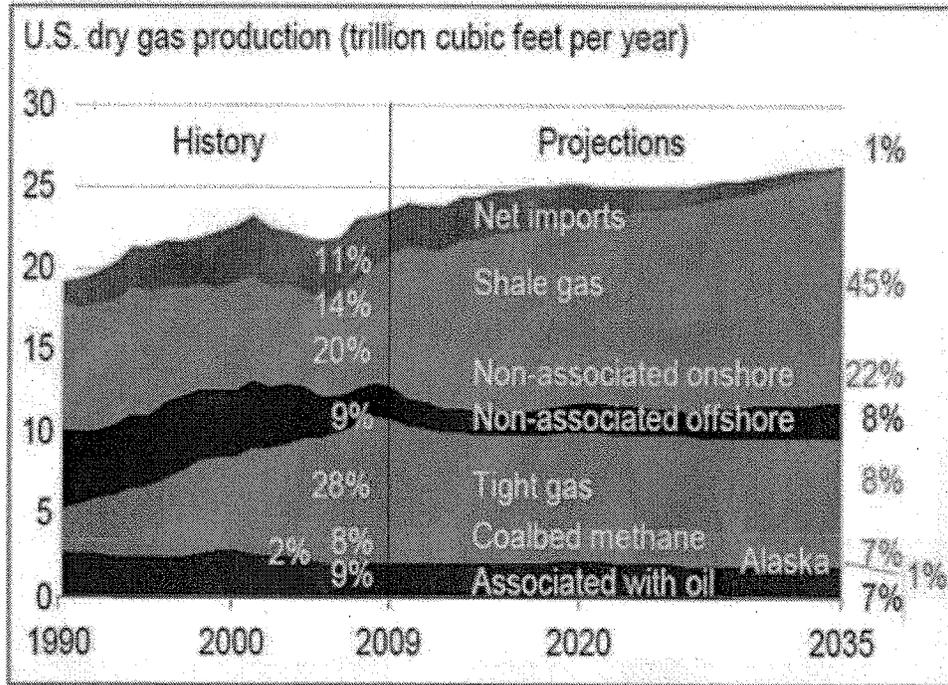
Figure 1 – U.S. Natural Gas Supply by Source – Projection Released May 2010



Source: DOE/EIA Annual Energy Outlook 2010 (EIA 2010a). Note that Tcf refers to trillion cubic feet.

In contrast, Figure 2 shows an accelerated growth of shale gas over a similar period of time. The new EIA projections released in December 2010 now show that shale gas will increase from 14% of the national supply in 2009 to 45% in 2035.

Figure 2 – U.S. Natural Gas Supply by Source – Projection Released December 2010



Source: DOE/EIA Annual Energy Outlook 2011 – Early Release Overview (EIA 2010b).

Shale Gas Resources in the United States

Important shale gas formations are found in many parts of the United States, as shown on the map in Figure 3. Much of the early rapid growth in shale gas production took place in the Barnett Shale formation near Fort Worth, Texas. As the technology evolved, operators began to explore other large shale formations in other parts of the country. The most active gas shales to date are the Barnett Shale, the Fayetteville Shale, the Antrim Shale, the Haynesville Shale, the Marcellus Shale, and the Woodford Shale. The Eagle Ford Shale, in southern Texas, has received a great deal of attention in the past year. Depending on the geographical location within the Eagle Ford Shale, a well may produce natural gas, natural gas liquids, or crude oil. A 2009 Shale Gas Primer, sponsored by DOE, includes a chart showing the gas production from several major shale gas formations (GWPC and ALL 2009 – see page 10).

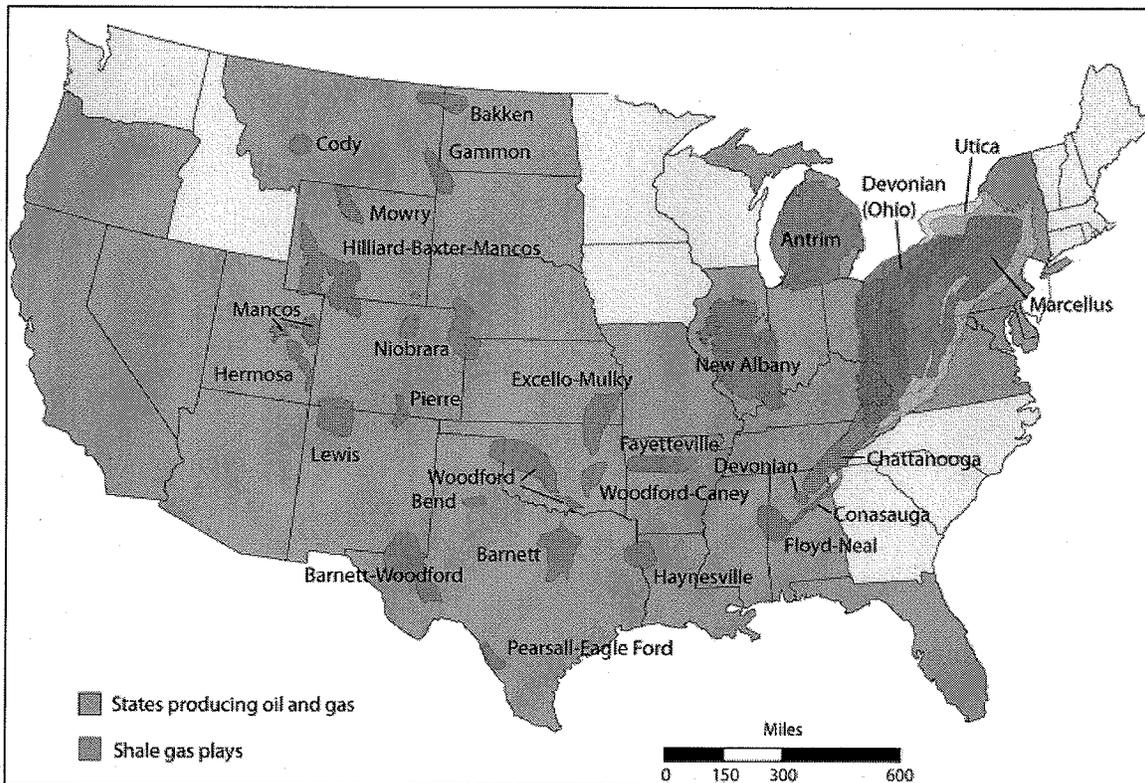
DOE/NETL Research Program

DOE's National Energy Technology Laboratory (NETL) administers an Environmental Program that aims to find solutions to environmental concerns by focusing on the following program elements:

1. Produced water and fracture flowback water management, particularly in gas shale development areas,
2. Water resource management in oil and gas basins,

3. Air quality issues associated with oil and gas exploration and production (E&P) activities,
4. Surface impact issues associated with E&P activities,
5. Water resource management in Arctic oil and gas development areas,
6. Decision-making tools that help operators balance resource development and environmental protection, and
7. Online information and data exchange systems that support regulatory streamlining.

Figure 3 – U.S. Shale Gas Plays



Source: Provided by staff from DOE's Office of Fossil Energy.

There are currently 27 extramural projects in the Environmental Program, with a total value of roughly \$32 million (not including participant cost-share). Approximately \$10 million of this total is directed toward projects led by industry, \$9 million to projects led by universities, \$11 million to state agencies and national non-profit organizations, and \$2 million to national laboratories for technical support to other project partners. The project portfolio is balanced between projects focused on technology development, data gathering, and development of data management software and decision support tools.

Some of these projects are referenced in this report. Program and individual project information can be found at the following NETL links:

- Technology Solutions for Mitigating Environmental Impacts of Oil and Gas E&P Activity <http://www.netl.doe.gov/publications/factsheets/program/Prog101.pdf>
- Natural Gas and Petroleum Projects, Environmental Solutions, Produced Water Management
http://www.netl.doe.gov/technologies/oil-gas/Projects/ENV_TOC.html#Produced

Purpose of Report

Water issues continue to play an important role in producing natural gas from shale formations. This report examines water issues relating to shale gas production in the Fayetteville Shale. In particular, the report focuses on how gas producers obtain water supplies used for drilling and hydraulically fracturing wells, how that water is transported to the well sites and stored, and how the wastewater from the wells (flowback and produced water) is managed.

Last year, Argonne National Laboratory made a similar evaluation of water issues in the Marcellus Shale (Veil 2010). Gas production in the Marcellus Shale involves at least three states, many oil and gas operators, and multiple wastewater management options. Consequently, Veil (2010) provided extensive information on water. This current study is less complicated for several reasons.

- Gas production in the Fayetteville Shale is somewhat more mature and stable than production in the Marcellus Shale.
- The Fayetteville Shale underlies a single state (Arkansas).
- There are only a few gas producers that operate the large majority of the wells in the Fayetteville Shale.
- Much of the water management information relating to the Marcellus Shale also applies to the Fayetteville Shale. Therefore, it can be referenced from Veil (2010) rather than being recreated here.
- The author has previously published a report on the Fayetteville Shale (Veil 2007) and has helped to develop an informational website on the Fayetteville Shale (Argonne and University of Arkansas 2008). Both of these sources, which are relevant to the subject of this report, are cited as references.

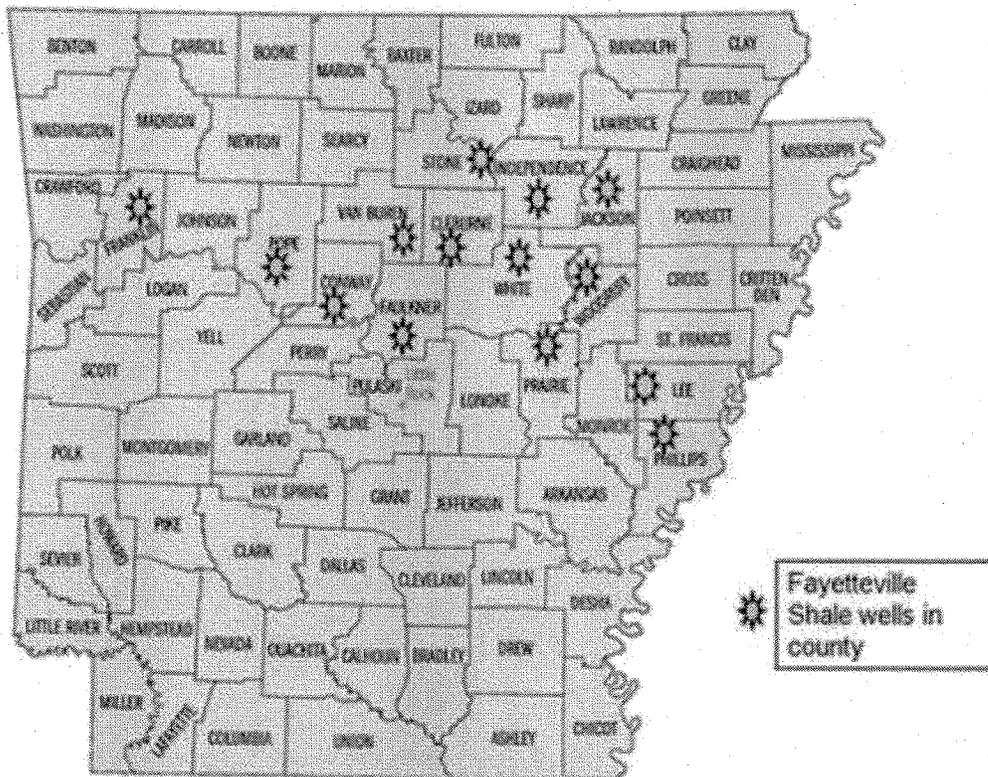
Chapter 2 – The Fayetteville Shale

The Fayetteville Shale is an unconventional natural gas reservoir located on the Arkansas side of the Arkoma Basin. The formation ranges in thickness from 50 to 550 feet and in depth from 1,500 to 6,500 feet. The shale is a Mississippian-age shale that is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas (Argonne and University of Arkansas 2008).

Location

The Fayetteville Shale play stretches across Arkansas from approximately Fort Smith east to beyond Little Rock, Arkansas. It is approximately 50 miles wide from north to south. Figure 4 shows those counties that have some gas wells drilled to the Fayetteville Shale formation. According to the Arkansas Oil and Gas Commission, although wells were drilled in Woodruff, Prairie, Phillips, and Lee counties, no production was attributed to any of those counties (Gates 2011).

Figure 4 – Map of Arkansas Showing the Counties with Fayetteville Shale Wells



Source: Map taken from Argonne and University of Arkansas (2008); updated using data from Arkansas Geology Survey (2010).

The most active area of natural gas development is from western Conway County through eastern White County. Due to the less than favorable geological conditions, development further to the east is not anticipated to proceed in the near future (Gates 2011).

Well Activity

The website of the Arkansas Geological Survey includes a spreadsheet of Fayetteville Shale well information (Arkansas Geological Survey 2010). The number of completed Fayetteville Shale wells per year (from that spreadsheet) is displayed in Table 1. The data show a steady increase through 2009, then a slight drop for 2010.

Table 1 – Fayetteville Shale Wells Completed per Year

Year	No. Fayetteville Shale Wells Completed
Pre-2004	2
2004	14
2005	46
2006	132
2007	456
2008	730
2009	892
2010	745
Total	3,017

Source: Arkansas Geological Survey (2010).

Table 2 offers another way of looking at the well data. It shows the total number of wells (including both active and inactive wells) and the number of active wells by operator. Only five operators have more than 50 wells under their control. In December 2010, Petrohawk announced that it was selling its Fayetteville Shale wells to XTO. Following completion of that transaction, only four operators will have a significant number of wells in the Fayetteville Shale.

The total number of wells in Table 1 differs from the total in Table 2. The Arkansas Geological Survey (2010) does not include a well completion date for all the wells listed; therefore, the total in Table 1 is lower than the total of the Total Wells column in Table 2. The total of the Active Wells column in Table 2 is lower than either of the other columns because not all of the completed or permitted wells are currently active.

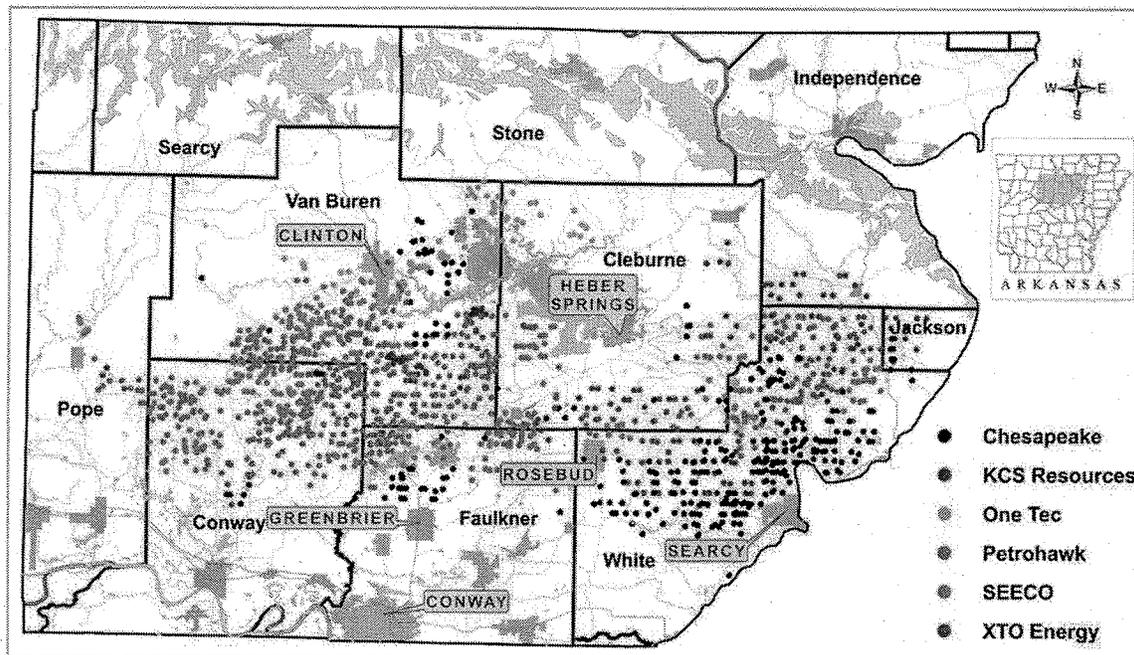
Table 2 – Number of Wells in Fayetteville Shale as of December 2010

Operator	Total Wells	Active Wells
Southwestern (SEECO)	2,198	1,681
Chesapeake	911	668
XTO	357	214
OneTec	114	107
Petrohawk	89	72
All others combined	152	76
Total	3,821	2,818

Source: Arkansas Geological Survey (2010).

Figure 5 shows the locations of producing Fayetteville Shale wells as of June 2010 from the top five operators (White 2010). Most of those wells are located in five counties (Cleburne, Conway, Faulkner, Van Buren, and White).

Figure 5 – Producing Wells from the Top Five Operators as of June 2010



Source: White (2010).

Fayetteville Shale Statistics

The Director of the Arkansas Geological Survey, Bekki White, made a presentation to an Environmentally Friendly Drilling program workshop in November 2010. Her presentation included various statistics about natural gas activities in the Fayetteville Shale (White 2010):

- Southwestern Energy Co. reports an average completed well cost of approximately \$2.8 million with an average horizontal lateral length of ~4,303 feet.
- Through August 2010, the cumulative production for the Fayetteville Shale was 1.4 Tcf.
- 50% of each well's reserves are produced in the first 4–5 years of production.
- An estimated 10,000 wells will eventually be drilled in the Fayetteville Shale gas play (based on 6 wells/section).
- This works out to about 20 years of drilling development (based on 500 wells/year).
- An “unofficial industry estimate” of recoverable gas from the acreage positions of Southwestern Energy and Chesapeake Energy is approximately 11 Tcf and 9 Tcf, respectively.

Chapter 3 – Water Needs and Availability

How Much Water Is Needed

In order to estimate the total annual amount of water needed for natural gas development activities in the Fayetteville Shale region, an estimate of water volume needed for each individual well must be multiplied by the anticipated number of wells that will be drilled in a high production year. Table 1 shows the number of Fayetteville Shale gas wells completed in each of the last 7 years. The numbers rose steadily until peaking in 2009 at 892 wells. The 2010 total was slightly lower, although this may be a reflection of the poor economy in 2010 and the relatively low price of natural gas. To extrapolate to a future high gas well year, the 2009 total is multiplied by 150% (=1,338 wells). This is not a precise multiplier, but is used to represent the potential for some future growth.

GWPC and ALL (2009) provide estimates of water requirements for four of the major shale gas plays. The water required for drilling a typical shale gas well ranges from 1,000,000 gallons in the Haynesville Shale to 60,000 gallons in the Fayetteville Shale, depending on the types of drilling fluids used and the depth and horizontal extent of the wells. The volume needed to fracture a well is considerably larger. According to GWPC and ALL (2009), the frac fluid volume ranges from 3,800,000 gallons per well in the Marcellus Shale to 2,300,000 gallons per well in the Barnett Shale. For the Fayetteville Shale, an estimated 2,900,000 gallons are used per well. Another estimate that is based on actual operator data is an average of 4,300,000 gallons of water used per well in the Fayetteville Shale (Mantell 2010a). It should be noted that these values are averages. The exact value for any specific well can vary significantly depending on a number of factors including the length of the lateral (horizontal section of the well) and the number of frac stages. Longer laterals, for example, will increase the volume of water required per well, but not necessarily the volume of water required relative to the length of the lateral or volume of gas produced.

Multiplying these per-well volumes by the extrapolated number of new wells completed in a future high production year gives an annual volume of 4.1 to 5.8 billion gallons for a full year. Assuming the water is required evenly over the whole year yields an estimated daily volume requirement of 11.2 to 15.8 million gallons/day.

These numbers are subject to various caveats, however:

- The estimates of maximum wells drilled could significantly overestimate or underestimate the actual quantity. Many factors can influence actual drilling rates.
- As gas companies refine and improve their efforts to recycle and reuse flowback and produced water from wells already fraced, the water needed per well may decrease.
- Conversely, if operators drill longer horizontal wells with more frac stages, the volume per well could increase.

Nevertheless, these volume projections give a reasonable idea of the water needs for natural gas production within the Fayetteville Shale.

Comparison of Natural Gas Water Needs to Other Water Users

The total water volume requirements make more sense when placed in context with the total water resources available within the state and with other existing and competing uses. The U.S. Geological Survey publishes water use estimates for the United States every 5 years. The most recent report (Kenny et al. 2009) reports on water use for 2005. Table 4 shows the 2005 water withdrawals for Arkansas by water-use category.

Table 4 – Water Withdrawal by Category for Arkansas in 2005

Category	Volume (million gallons per day)
Public Supply	266
Domestic	0
Irrigation	1,510
Livestock	23
Aquaculture	11
Industrial	113
Mining	1
Thermoelectric	2,000
Total	3,920

Source: Kenny et al. (2009).

Table 5 compares the estimated future water withdrawals for shale gas production with the 2005 actual water withdrawals from Kenny et al. (2009). The projected volume of water needed in even a high well completion year is just a fraction of 1% of the total water already withdrawn within Arkansas.

Table 5 – Comparison of Water Needed for Shale Gas and Total Existing Water Withdrawals

	Volume (Million gallons per day)	Water Required for Shale Gas Production Compared to Total Withdrawal (%)
Water needed for shale gas	11.2–15.8	–
Total water withdrawal	3,920	0.29–0.40

Although the counties in which Fayetteville Shale production is centered are only a portion of the entire state, these calculations suggest that sufficient water should be available within the region to support natural gas development. However, that does not mean that every tributary to every stream has sufficient surplus water resources, nor does it mean that water should be withdrawn in equal quantities during all seasons of the year. Drought conditions will lower stream flows so that even existing users may face shortages during those periods. Gas producers would be well served to plan ahead to collect and store water during times of abundance so that the water is available when needed.

Chapter 4 – Water Issues Associated with Shale Gas Production

Water plays a role in different aspects of shale gas production. Three important water issues are discussed in this chapter. Most of the photos used in this chapter were taken by the author during a field tour of the Fayetteville Shale in August 2007. Any photos that were taken from other locations are noted accordingly.

Stormwater Runoff from Disturbed Areas

Before a new well can be drilled, the operator clears vegetation and constructs a pad for the drilling rig and other equipment used in preparing the well and an access road to get from the county road to the well site. The operator pays a use fee to the landowner for disturbing an area. According to Veil (2007), one of the large operators pays for disturbing 500 feet by 500 feet of land, plus the area of the access road. In practice, however, the operator generally clears only 300 feet by 250 feet for the pad and the reserve pit plus two adjacent smaller “rig ditch pits,” which collect fluids that fall onto the footprint area beneath the rig. The pits are constructed with a plastic liner, and the pad and access road are covered with gravel. Figure 6 shows the gravel pad at a recently completed well site. Figure 7 shows the gravel access road, Figure 8 shows the reserve pit, and Figure 9 shows one of the adjoining rig ditch pits. Figure 10 shows a reclaimed reserve pit location.

Figure 6 – Newly Constructed Well Showing Gravel Pad



Figure 7 – Gravel Access Road

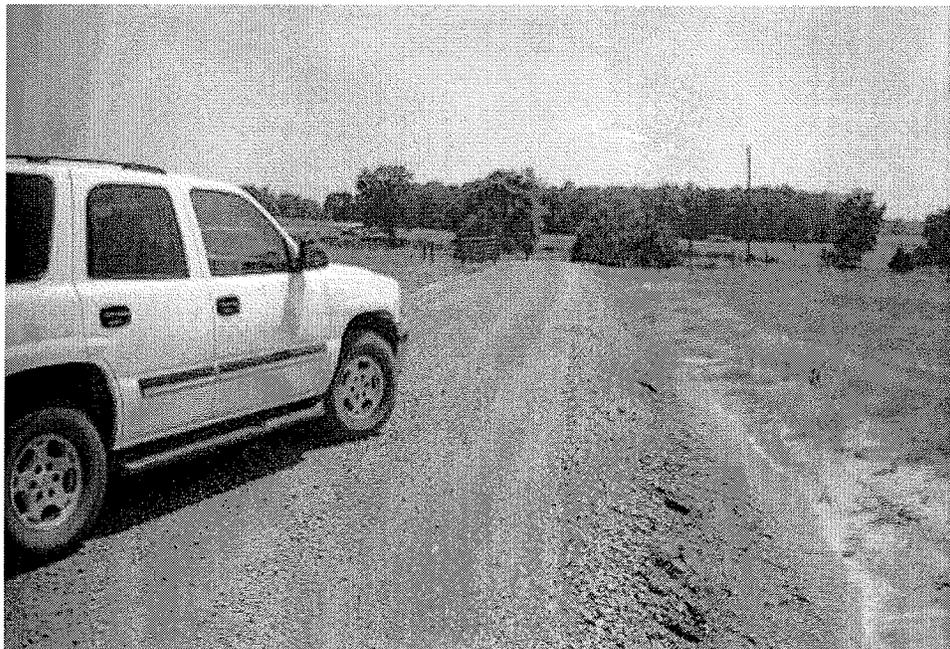


Figure 8 – Reserve Pit

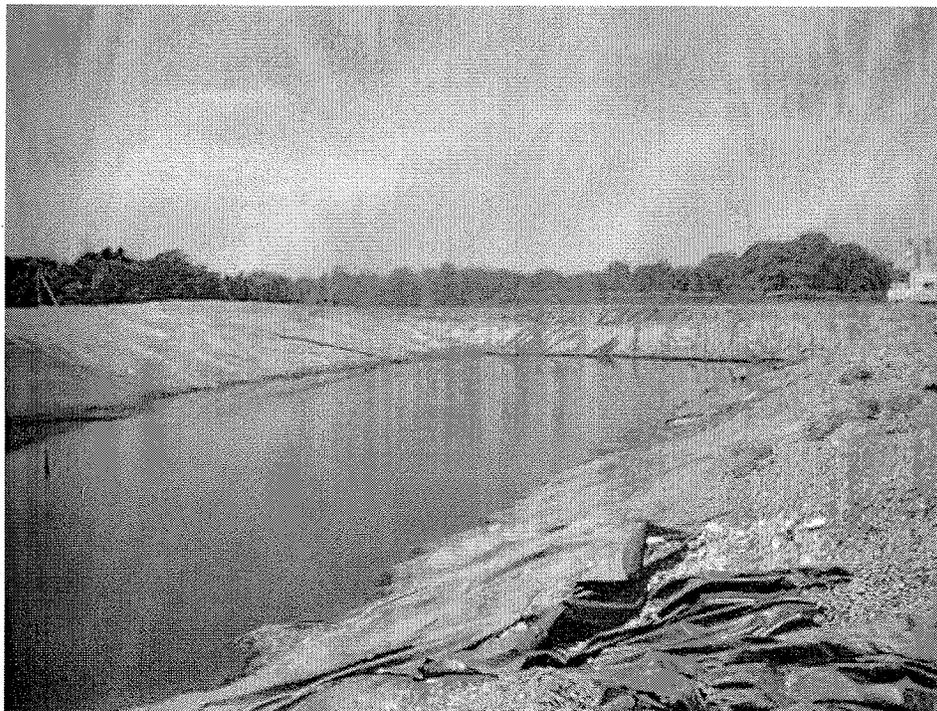


Figure 9 – Rig Ditch Pit



Figure 10 – Reclaimed Reserve Pit



Operators are required to employ appropriate management practices to control stormwater runoff. These are included in a stormwater erosion and sediment control plan that is prepared for each well site. These plans can include implementation of technologies such as runoff control barriers (e.g., filter fences, surface stabilization) and selection of well pad location within a lease to minimize slope or proximity to streams. Other examples of approaches to minimize environmental impacts can be found at the Minimizing Impacts of Site Preparation page¹ of Argonne and University of Arkansas (2008).

Water Supply for Drilling and to Make Up Frac Fluids

The second important water issue involves finding an adequate and dependable supply of water to support well drilling and completion activities. Water used for drilling and making up frac fluids can come from several sources: surface water bodies, groundwater, municipal potable water supplies, or reused water from some other water source (most commonly this is flowback water from a previously fractured well).

The two per-well water volumes cited in Chapter 3 are: (a) 60,000 gallons for drilling fluids + 2,900,000 gallons for frac fluids = 2,960,000 gallons (GWPC and ALL 2009), and (b) 4,300,000 gallons (Mantell 2010a). Water can be brought to the site by numerous tank trucks. However, operators try to avoid hauling multiple truckloads of water across unimproved public county roads. Consequently, where another source of water is available within a mile or so, it can be piped to the site. Figure 11 shows a temporary pipeline made of aluminum irrigation pipe used to convey water from a pond to the well site.

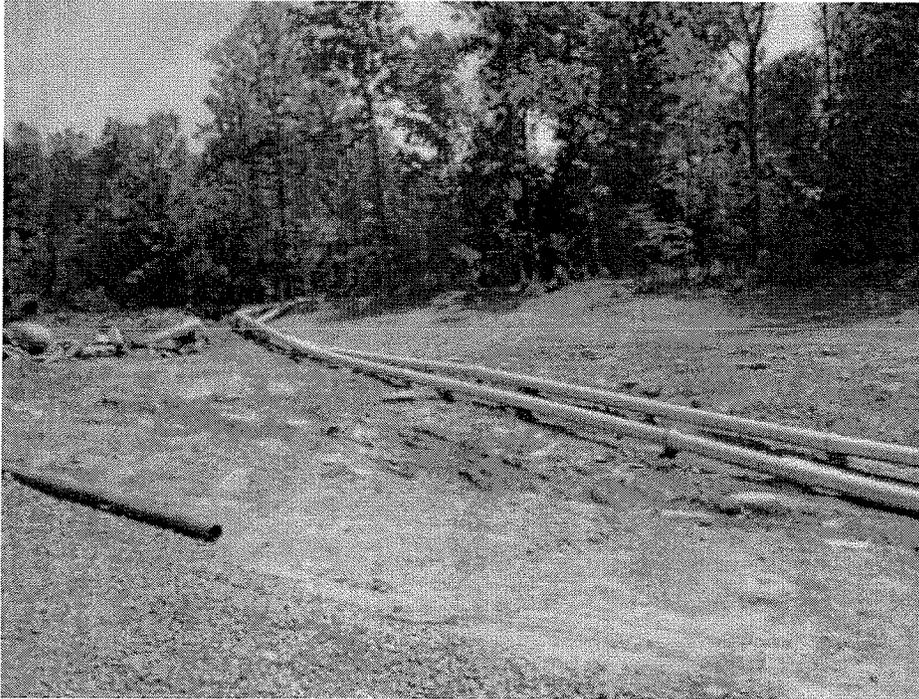
One operator has constructed a large reservoir (500 acre-foot capacity) near the Little Red River and has plans to withdraw approximately 1,500 acre-feet of water on an annual basis from the river during high flow. The operator plans to construct distribution pipelines from this reservoir to strategic distribution points throughout White County, where the water will be available for drilling and well fracturing for 1,200 to 2,000 wells (Satterfield et al. 2008). Operators are also constructing multiple small, 1- to 5-acre reservoirs throughout the Fayetteville Shale region, from which water will be piped to individual well pads for frac jobs (Argonne and University of Arkansas 2008).

Withdrawal of water from surface water bodies or from groundwater is regulated by the Arkansas Natural Resources Commission (ANRC), or if the site is on federal land, by the Bureau of Land Management and/or the Army Corps of Engineers. For waters regulated by the ANRC, operators must apply for a permit to withdraw water and report the amount of water withdrawn annually. The Regulatory Requirements Associated with Well Preparation page² of Argonne and University of Arkansas (2008) outlines the requirements for withdrawing water.

¹ The URL is <http://lingo.cast.uark.edu/LINGOPUBLIC/envIRON/siteprep/index.htm>. Accessed January 11, 2011.

² The URL is <http://lingo.cast.uark.edu/LINGOPUBLIC/reg/wellprep/index.htm>. Accessed January 11, 2011.

Figure 11 – Aluminum Pipe Used to Convey Water



Management of Water Flowing to the Surface from the Well

The third important water issue involves managing the water that comes to the surface from the gas well. During the frac job, the operator injects a large volume of water into the formation. Once the frac job is finished, the pressure is released, and water begins returning to the surface. Some companies and organizations consider flowback to be a process rather than a fluid stream. They use the term “flowback” to describe the process of excess fluids and sand returning through the borehole to the surface. They further consider all the water produced during flowback operations to be produced water. However, most sources distinguish between: (a) the fluids returning to the surface in the first few hours to several days following a frac job (flowback water), which consists primarily of the water that was injected as a component of the frac fluids, and (b) the lower volume of ongoing, long-term water flow to the surface (produced water). Over an extended period of time, the volume of produced water from a given well decreases. While acknowledging these different points of view, this paper follows the convention of describing flowback as a fluid stream different from produced water.

The initial flowback is typically collected in frac tanks parked on the well site (see Figure 12). However, a significant volume of water comes out of the well at a slower rate over an extended period of time (the produced water). This is collected in an onsite water storage tank (Figure 13). The tank is pumped out periodically by vacuum trucks, which haul the water offsite for disposal.

Figure 12 – Frac Tanks at Well Site Where Frac Job is Taking Place

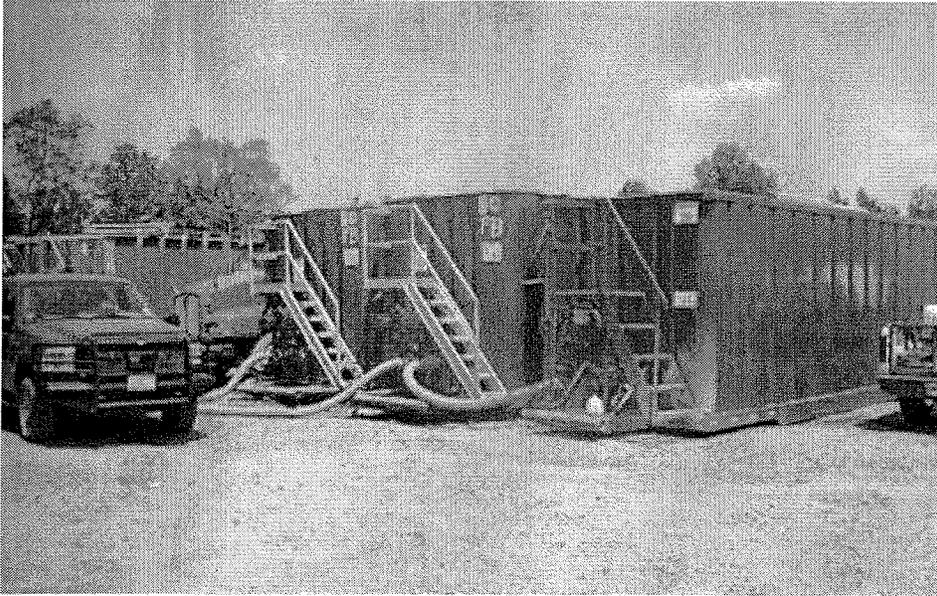
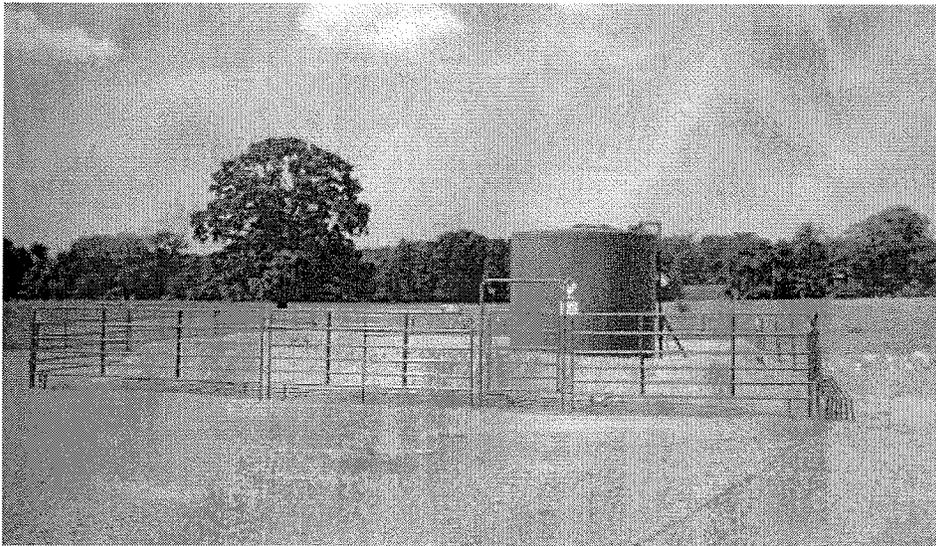


Figure 13 – Water Storage Tank at Producing Well Site



Not all of the injected frac fluid returns to the surface. GWPC and ALL (2009) report that only a portion (from less than 30% to more than 70%) of the original frac fluid volume used in shale formations returns as flowback. The rest of the water remains in pores within the formation. However, anecdotal reports from Marcellus Shale gas operators suggest that the actual percentage is at or below the lower end of that range. Hoffman (2010) notes that, as of

January 2010, the Susquehanna River Basin Commission (SRBC) had data for 131 wells that had been drilled in the Marcellus Shale. For that dataset, about 13.5% of the injected frac fluid was recovered. However, both the volume and flow rates of flowback and produced water are known to vary significantly between different shale plays, so the applicability of data from one play to another is uncertain. Based on an informal conversation with a representative of one of the large Fayetteville Shale gas producers, the combined return volume of flowback water and subsequent produced water for the Fayetteville shale is toward the lower end of the range, or about 25% (Mantell 2010b).

Operators must manage the flowback and produced water in a cost-effective manner that complies with state regulatory requirements. Although various options have been used in other shale gas plays, the primary options used in the Fayetteville Shale are underground injection through a disposal well (either owned by the operator or by a third-party commercial disposal company) or reuse for a future frac job either with or without treatment. A few other examples are discussed below.

During the summer of 2010, the author wrote to each of the major gas operators in the Fayetteville Shale and to the Arkansas Oil and Gas Commission (AOGC) to collect information on how the flowback and produced water from Fayetteville Shale gas production is managed. Only Southwestern Energy and the AOGC provided replies to the requests. Additional information on Chesapeake's practices was obtained from presentations made by Chesapeake staff at conferences.

Southwestern Energy indicated that at most sites, the flowback water is collected in frac tanks, filtered, then hauled by tank truck to the next site, where it is reused in new frac fluid. In the future, the water may be pumped to the next site instead of trucking it. The longer-term, ongoing produced water is collected onsite, then hauled to Class II injection wells. Some of these are owned and operated by Southwestern Energy, while others are commercial disposal wells (Lane 2010).

Steve Gates of the AOGC offered a similar, but less detailed reply:

"Larger operators have company-owned disposal wells, smaller operators are using commercial wells. Water will be reused where practical" (Gates 2010).

Although the information is now a few years old, Puder and Veil (2006) developed a database of most of the commercial oil field waste disposal companies operating in the United States. The database lists 10 commercial waste management companies operating in Arkansas. Five of these facilities indicate that they accept produced water for disposal. Four of the five utilize underground injection, while the fifth facility uses land application.³ The database does not indicate whether the incoming produced water is generated from Fayetteville Shale gas wells or from other oil- and gas-producing fields in Arkansas.

More current injection well information can be extracted from the Arkansas Geological Survey (2010). The spreadsheet shows 14 injection wells from the B-43 field (the Fayetteville Shale)

³ Although Puder and Veil (2006) list one waste management facility that disposes of produced water by land application, a representative of a large gas producer suggests that most large operators do not utilize land application for disposal (Mantell 2011).

that are active as of December 2010 (see Table 3). Of those, six list SEECO as the operator, two list Chesapeake, and one lists XTO. The other five wells list operators other than the large gas producers.

Table 3 – Active Injection Wells in the Fayetteville Shale as of December 2010

Operator	Well Name	County	Date Completed
Chesapeake	Cooper	White	10/4/2007
Chesapeake	Trammel	Faulkner	12/18/2008
Clarita Oper.	Edgmon, Wayne L.	Faulkner	No date provided
Deep-Six	EW Moore Estate	Faulkner	1/10/2008
Peak Water Sys.	Peak Water Systems	Van Buren	9/20/2010
Petrowater	Bennett	Van Buren	5/22/2009
Poseidon Energy	Poseidon	White	3/6/2009
SEECO	Campbell	Conway	12/23/2009
SEECO	Scroggins	Faulkner	1/15/2010
SEECO	Underwood	Faulkner	1/21/2010
SEECO	Canady	Conway	10/12/2010
SEECO	Griffin Mtn. 1	Conway	No date provided
SEECO	Griffin Mtn. 2–28	Conway	No date provided
XTO Energy	Ferguson	Independence	10/9/2009

Source: Arkansas Geological Survey (2010).

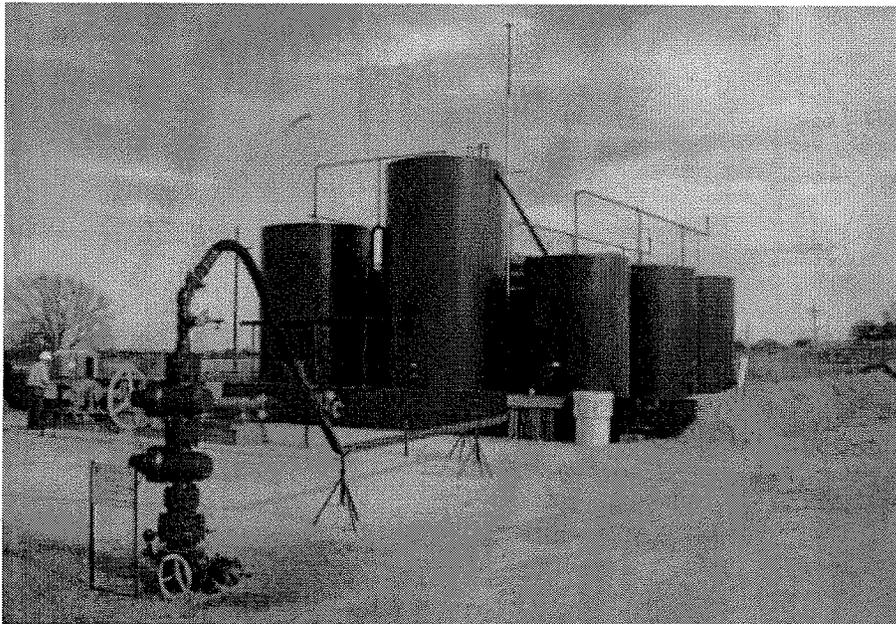
To give readers a sense of what a commercial disposal well looks like, Figure 14 shows a commercial flowback and produced water disposal well located southwest of Ft. Worth, Texas, in the Barnett Shale region. Flowback and produced water are delivered by tank truck and are transferred into the storage tanks. As necessary, the flowback and produced water are injected into a deep formation that has sufficient porosity and injectivity to accept the water.

According to Mantell (2010a), Fayetteville Shale produced water⁴ generally has good quality for reuse. Fayetteville Shale produced water has low total dissolved solids (TDS),⁵ low total suspended solids (TSS), and low scaling tendency. The volume of water generated is typically sufficient to justify reuse. Chesapeake is currently meeting approximately 6% of its drilling and fracturing needs in the Fayetteville Shale with produced water reuse with a target goal of 20% reuse in the play. Since TSS levels are low, very limited treatment (filtration) is employed, if needed, prior to reuse. Logistics and economics are currently the main limiting factor in preventing higher levels of reuse in the Fayetteville Shale.

⁴ As noted earlier in this chapter, some authors do not distinguish between flowback water and produced water. Instead, they refer to all water returning to the surface from a completed well as produced water. The reference cited for this paragraph follows that naming convention.

⁵ TDS is relatively low compared to other shale plays but still may be high by most standards. Fayetteville Shale produced water averages 20,000 to 25,000 ppm TDS (Mantell 2011).

Figure 14 - Injection Well and Tank Battery at Commercial Disposal Facility in Texas



Other Water Management Options

Several companies have employed advanced treatment technologies to treat the flowback and produced water. Fountain Quail uses a thermal distillation process (the Aqua-Pure NOMAD) to generate very clean water and concentrated brine (Veil 2008). While typically used in other applications as a mobile treatment system, the NOMAD unit will be employed in Arkansas as part of a new fixed treatment facility, Arkansas Saltwater Recycling, LLC, in Twin Groves, Arkansas (Halldorson 2010). The facility has a permit from the Arkansas Department of Environmental Quality to discharge the treated water into a nearby river. If an operator needs clean water for a new frac job, the treatment plant will return the treated water to them. As of mid-January 2011, Fountain Quail is ready to open the plant and has all of the permits in order. The company is currently having discussion with the Fayetteville Shale producers to confirm level of commitment before actually moving the equipment in (Halldorson 2011). Other competing thermal treatment processes have been used in different shale gas plays, and may also have been tested in the Fayetteville Shale.

Another technology that has recently seen some use in the Fayetteville Shale for treating produced water and flowback water is referred to as advanced oxidation. Ecosphere Technologies, Inc., has commercialized an advanced oxidation process (Ozonix®) that combines ozone generation, cavitation, and electro-chemical decomposition in a reaction vessel. The process reduces the use of biocides, scale inhibitors, and friction reducers when the treated water is reused for frac fluid. During 2009–2010, the Ozonix® technology was used on over 100 wells in several shale plays to destroy bacteria and inhibit scale formation, including some tests conducted in the Fayetteville Shale. The author was unable to obtain any data on the performance of the system as used in the Fayetteville Shale region.

Chapter 5 – Findings

There is a great deal of interest in natural gas production in the Fayetteville Shale. This report describes three types of water issues that arise from shale gas development in the Fayetteville Shale. Those three issues are:

- Controlling the stormwater runoff from disturbed areas,
- Obtaining sufficient freshwater supply to conduct frac jobs on new wells, and
- Managing the flowback water and produced water from the well.

Some of the key findings are listed below:

1. Fayetteville Shale frac jobs typically inject several million gallons of frac fluids (which are mostly water).
2. After the initial return of flowback water, within a few weeks following completion of the frac job, most wells continue generating formation water (produced water) at a lower rate for many years.
3. The larger oil and gas operators in the Fayetteville Shale are working to collect the initial surge of flowback water from the newly fraced wells. The flowback may be given some basic treatment, such as filtration, then used as makeup water for new frac fluids in another well. The ongoing flow of produced water is typically collected in tanks at each well site. Periodically, the tank contents are collected by vacuum truck and hauled to injection wells, operated either by the gas company or by a commercial waste disposal company.
4. A few other more advanced technologies are being used at some locations to treat flowback and produced water. They also generate clean fluids that can be reused in other frac jobs or may be permitted for surface discharge.
5. Based on estimates described in Chapter 3, there should be adequate surplus fresh water available within the Fayetteville Shale region to provide the needed water supply for drilling and fracing new shale gas wells.

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