Quantitative Support for EPA's Finding of No Widespread, Systemic Effects to Drinking Water Resources from Hydraulic Fracturing

Prepared for: energy API

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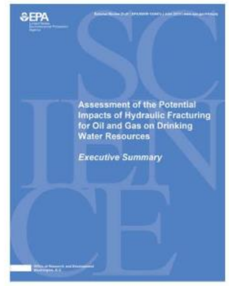
Quantitative Support For EPA's Finding of No Widespread, Systemic Effects to Drinking Water Resources from Hydraulic Fracturing

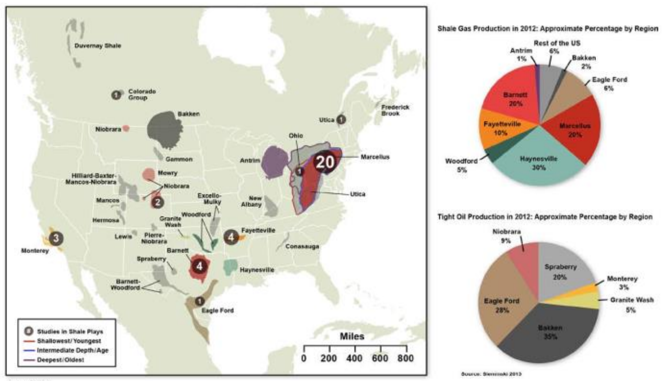
The US EPA published its draft assessment of the impacts of hydraulic fracturing on drinking water resources. The assessment identified potential causes of drinking water impairment, and evaluated the extent to which hydraulic fracturing has been identified as a cause of impairment. EPA concluded that there is **no evidence of widespread, systemic impacts on drinking water resources in the United States**, and that the number of identified cases was small compared to the number of hydraulically fractured wells.

In its review of the EPA study, the Scientific Advisory Board commented that EPA should provide **quantitative support** for its finding, including, that it more clearly describe the **systems of interest**, **the scale of impacts**, and **definitions of terms**.



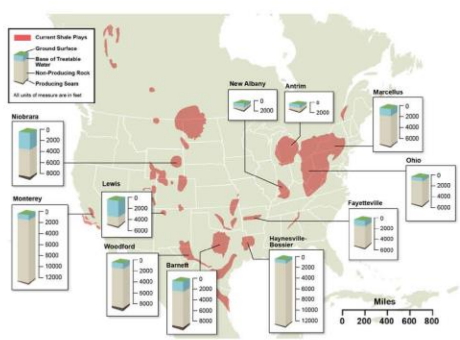
Case Studies & Research Quantitatively Support EPA's Finding

EPA reviewed state-of-the-science studies and employed a structured and logical method of analysis to reach its conclusions by focusing on those areas where hydraulic fracturing was conducted in close proximity to drinking water supplies and/or residents. With this approach, if a significant correlation between impaired drinking water resources and hydraulic fracturing existed, EPA would have identified it; however, the results did not support this finding. Further quantitative support comes from a large, credible body of case studies and peer-reviewed scientific literature from around the county that conducted quantitative analysis and modeling of potential causative mechanisms for hydraulic fracturing fluids to come into contact with drinking water resources. Incorporation of these studies into their analysis further demonstrates that there are no widespread effects to drinking water resources from hydraulic fracturing.



Quantitative support for EPAs finding comes from studies in all the major oil and natural gas producing shale basins in the country, with an emphasis on those states with the most hydraulic fracturing

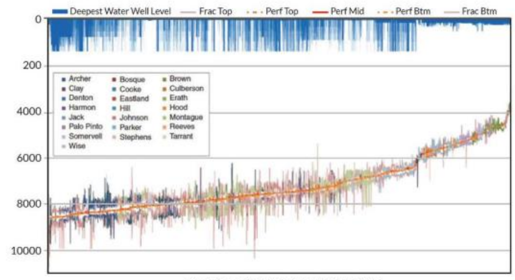
Basis of Terms & Definitions Used by EPA



Scale of Impacts: EPA considered that, at the scale of 25,000-30,000 new hydraulically fractured wells annually, the few instances of potential impairment are neither systemic nor widespread.

At a geographic scale, the study addresses impacts from the national to the county level. Local impacts, at the scale of a well pad, occur rarely.

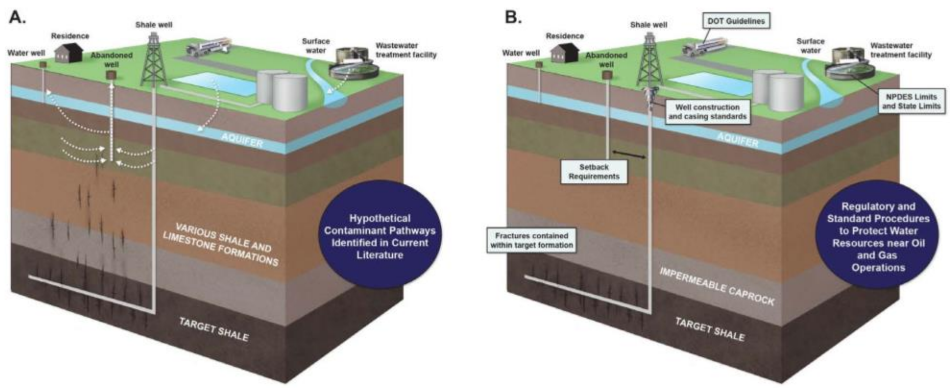
The range of conditions nationally, statewide, and locally were quantified by the EPA study



Systems of Interest: EPA defines drinking water resources as any body of ground water or surface water that now serves, or in the future could serve, as a source of drinking water for public or private use. This is broader than most federal and state regulatory definitions of drinking water and encompasses both fresh and non-fresh bodies of water.

Industry Practices and State Regulations Lower Risk, Limits Incidents

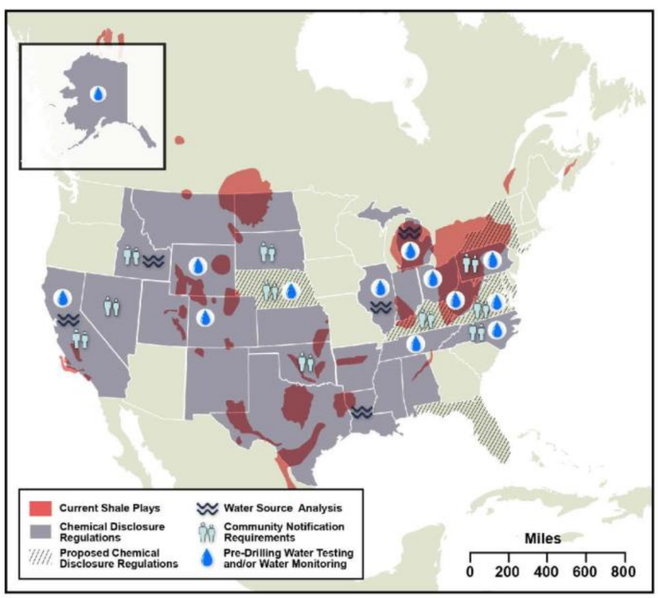
With an emphasis on **prevention** of an incident through the application of well design/construction and equipment safeguards, Industry, EPA and states have together systematically limited the level of risk of hydraulic fracturing fluids impairing drinking water resources. EPAs finding of no widespread effects to drinking water quality is a reflection of the effectiveness of these practices. Their finding makes sense. The California Council on Science and Technology's 2015 comprehensive study of the effects of hydraulic fracturing came to a similar conclusion as EPA, providing further quantitative validation.



Industry, EPA, and the States seek to prevent impairment of water resources through identification of potential impairment mechanisms (left), and the providing suitable controls (right)

Monitoring Provides Ongoing Quantitative Data Supporting EPA's Finding of No Widespread Effects to Drinking Water Resources

Recent State water monitoring requirements are **providing further quantitative support** that hydraulic fracturing is not leading to widespread, systemic effects to drinking water resources. For example, a comprehensive monitoring program has just been initiated in California, based on an extensive study by Lawrence Livermore National Labs, Lawrence Berkeley Lab, and other universities. Existing data quantitatively supports EPAs principal finding, and ongoing monitoring provides additional assurance and a growing database to further prove out the finding. These governmental requirements have kept oil and gas development as one of the most highly regulated industrial sectors in the US.



Monitoring is a relatively recent regulatory requirement and will provide data for EPA to prove out finding.

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SECTION 1

Introduction

In June 2015, the U.S. Environmental Protection Agency (EPA) released a draft report titled *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources* (EPA Draft Assessment) (EPA 2015a). The EPA Draft Assessment was conducted in response to a request from Congress in 2010 to evaluate the relationship between hydraulic fracturing and drinking water resources, and evaluated available scientific literature and data to identify factors affecting the frequency and severity of potential impacts. The EPA Draft Assessment concludes that the number of known instances of drinking water resources impairment was small in comparison to the number of wells hydraulically fractured (approximately 25,0000-30,000 annually), and that there is no evidence that hydraulic fracturing has "led to widespread, systemic impacts on drinking water resources in the United States" (EPA 2015a).

The Science Advisory Board (SAB), a group established in 1978 under direction from Congress to provide scientific advice to the EPA, created the Hydraulic Fracturing Research Advisory Panel (Advisory Panel), to provide advice and recommendations to EPA on its research and to peer review the draft report of the study when released to the public. The Advisory Panel reviewed the EPA Draft Assessment, the SAB considered the comments, and, in August 2016, transmitted their final review to the EPA. With respect to EPA's conclusion that there is no evidence that hydraulic fracturing has led to widespread, systemic impacts on drinking water resources, the SAB recommended that EPA provide quantitative support for this finding, and that EPA more clearly describe the systems of interest, the scale of impacts, and definitions of terms.

This report provides quantitative information to support EPA's conclusion as follows:

1. Summarizing peer-reviewed case studies and research by academia, government, and industry that quantify the limited effect of all phases of hydraulic fracturing on water resources; a significant amount of study from across the country at a variety of scales has established the potential causative mechanisms for impairments to drinking water quality, and that hydraulic fracturing (primarily through surface spills) has rarely led to impairments. These studies have found no direct correlation between the hydraulic fracturing process and quality of drinking water supplies.

2. Summarizing other recent (post-2014) state and federal regulatory reviews that had a similar mandate to EPA's: to evaluate the potential effects of hydraulic fracturing to drinking water resources, and other environmental resources. The most comprehensive are the studies conducted by the California Council on Science and Technology (CCST), which evaluated the effects of well stimulation (focusing on hydraulic fracturing) in California for the US Bureau of Land Management (CCST 2014) and the state of California Department of Conservation (CCST 2015). The CCST concluded that the direct effects of hydraulic fracturing appear small, and that good management and mitigation measures can address the vast majority of potential direct impacts of well stimulation.

> **EPA's Definition of "*Widespread, Systemic*"**
>
> EPA concluded that there is not a significant correlation between hydraulic fracturing and drinking water resources impairment, and correctly described this finding as not "widespread" or "systemic". EPA's conclusion is based on the very few instances of water quality contamination from the entire hydraulic fracturing process. Most incidents were localized incidents (i.e. surface spills) and do not represent a widespread or systemic impact.

3. EPA's finding of no widespread, systemic effects to drinking water resources from hydraulic fracturing is a reflection of the effectiveness of industry practices and regulatory frameworks in protecting this resource. Many states and some local governments have enacted or revised laws or ordinances specifically addressing hydraulic fracturing. Many of the states where hydraulic fracturing is occurring have initiated groundwater testing and/or monitoring programs as a condition of permit issuance. Eleven major oil and gas producing states have implemented baseline and on-going water quality monitoring programs, including California, Colorado, Wyoming and Pennsylvania. Collectively, states with water quality monitoring programs represent 30 percent of oil and gas production in the U.S. (EIA 2016). Collectively, these programs are providing comprehensive and proof positive information that hydraulic fracturing is not leading to widespread, systemic effects to drinking water resources. Describing the increased level of water quality monitoring and reporting that is currently required over most of the country, including the states with significant application of hydraulic fracturing.

Taken together, both lines of evidence support EPA's conclusion that there is no evidence hydraulic fracturing has "led to widespread, systemic impacts on drinking water resources in the United States". Industry practices and regulatory programs targeting prevention of incidents support this conclusion and explain the result. In addition, there is sufficient monitoring in place, overseen by state authorities, to continue gathering data that supports this finding.

Before providing the information from each line of evidence in this report, the specific finding of the EPA Draft Assessment is provided, followed by the SAB comment.

What EPA Said	What SAB Said
Through this national-level assessment, we (EPA) have identified potential mechanisms by which hydraulic fracturing could affect drinking water resources. Above ground mechanisms can affect surface and ground water resources and include water withdrawals at times or in locations of low water availability, spills of hydraulic fracturing fluid and chemicals or produced water, and inadequate treatment and discharge of hydraulic fracturing wastewater. Below ground mechanisms include movement of liquids and gases via the production well into underground drinking water resources and movement of	***The SAB has concerns regarding the clarity and adequacy of support for several major findings presented within the draft Assessment Report that seek to draw national-level conclusions regarding the impacts of hydraulic fracturing on drinking water resources.*** The SAB is concerned that these major findings as presented within the Executive Summary are ambiguous and appear inconsistent with the observations, data, and levels of uncertainty presented and discussed in the body of the draft Assessment Report. Of particular concern in this regard is the high-level conclusion statement on page ES-6 that "We did

liquids and gases from the fracture zone to these resources via pathways in subsurface rock formations.	not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States."
We (EPA) did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States. Of the potential mechanisms identified in this report, we found specific instances where one or more of these mechanisms led to impacts on drinking water resources, including contamination of drinking water wells. The cases occurred during both routine activities and accidents and have resulted in impacts to surface or ground water. Spills of hydraulic fracturing fluid and produced water in certain cases have reached drinking water resources, both surface and ground water. Discharge of treated hydraulic fracturing wastewater has increased contaminant concentrations in receiving surface waters. Below ground movement of fluids, including gas, most likely via the production well, have contaminated drinking water resources. In some cases, hydraulic fracturing fluids have also been directly injected into drinking water resources, as defined in this assessment, to produce oil or gas that co-exists in those formations.	***The SAB finds that the EPA did not support quantitatively its conclusion about lack of evidence for widespread, systemic impacts of hydraulic fracturing on drinking water resources, and did not clearly describe the system(s) of interest (e.g., groundwater, surface water), the scale of impacts (i.e., local or regional), nor the definitions of "systemic" and "widespread."*** The SAB observes that the statement has been interpreted by readers and members of the public in many different ways.
The number of identified cases where drinking water resources were impacted are small relative to the number of hydraulically fractured wells. This could reflect a rarity of effects on drinking water resources, or may be an underestimate as a result of several factors. There is insufficient pre- and post-hydraulic fracturing data on the quality of drinking water resources. This inhibits a determination of the frequency of impacts. Other limiting factors include the presence of other causes of contamination, the short duration of existing studies, and inaccessible information related to hydraulic fracturing activities.	***The SAB concludes that if the EPA retains this conclusion, the EPA should provide quantitative analysis that supports its conclusion that hydraulic fracturing has not led to widespread, systemic impacts on drinking water resources.***

This state-of-the-science assessment contributes to the understanding of the potential impacts of hydraulic fracturing on drinking water resources and the factors that may influence those impacts. The findings in this assessment can be used by federal, state, tribal, and local officials; industry; and the public to better understand and address any vulnerabilities of drinking water resources to hydraulic fracturing activities. This assessment can also be used to help facilitate and inform dialogue among interested stakeholders, and support future efforts, including: providing context to site-specific exposure or risk assessments, local and regional public health assessments, and assessments of cumulative impacts of hydraulic fracturing on drinking water resources over time or over defined geographic areas of interest. Finally, and most importantly, this assessment advances the scientific basis for decisions by federal, state, tribal, and local officials, industry, and the public, on how best to protect drinking water resources now and in the future.	***The SAB also recommends that the EPA discuss the significant data limitations and uncertainties, as documented in the body of the draft Assessment Report, when presenting the major findings.*** Regarding the EPA's findings of gaps and uncertainties in publicly available data that the agency relied upon to develop conclusions within the draft Assessment Report, the EPA should clarify and describe the different databases that contain such data and the challenges of accessing them, and make recommendations on how these databases could be improved to facilitate more efficient investigation of the data they contain.

SECTION 2

Studies Have Not Found Widespread, Systemic Impacts

EPA's Definition of *Drinking Water Resources*

Drinking water resources are defined within EPA's Draft Assessment as any body of ground water or surface water that now serves, or in the future could serve, as a source of drinking water for public or private use. This is broader than most federal and state regulatory definitions of drinking water and encompasses both fresh and non-fresh bodies of water. Trends indicate that both types of water bodies are currently being used, and will continue to be used in the future, as sources of drinking water (EPA 2015).

The causative mechanisms through which hydraulic fracturing fluids could potentially impair drinking water resources are well-known and documented. Identifying the means by which water resources could be impaired was the first step in EPA's approach. Quantitative studies in the EPA report, and provided here, substantiate EPA's finding that hydraulic fracturing has not caused "widespread, systemic effects" to drinking water resources. The studies summarized below and in **Appendix A** are the product of many years of research and monitoring by university researchers, industry groups, and government agencies. This literature review mirrors EPA's approach in analyzing the causative mechanisms of impairing drinking water resources from hydraulic fracturing by evaluating the stages of an unconventional play that involve the hydraulic fracturing water cycle (HFWC) - water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and disposal (Figure 1). Breaking down the HFWC into stages allows for the identification and investigation of the specific pathways that may affect drinking water quality, and structures the basis for quantitatively assessing the state of the science. Table 1 provides a summary of findings that correlates each HFWC stage with the specific pathways for chemical migration, potential effects, and findings from technical sources included in **Appendix A**.

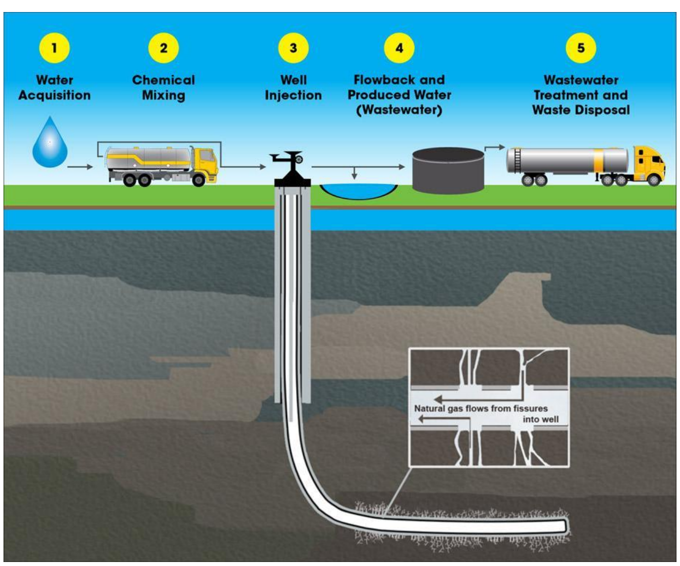

Figure 1 – Hydraulic Fracturing Water Cycle (EPA 2015a)

As provided below and in **Appendix A**, the quantitative and peer-reviewed findings speak to the absence of a frequent and pervasive issue of hydraulic fracturing impairing drinking water resources. The overall body of scientific literature does not show a correlation between hydraulic fracturing and drinking water resources impairment, with a nominal number of instances of impairment in comparison to the amount of hydraulic fracturing occurring. EPA found that 25,000-30,000 new wells were drilled and hydraulically fractured annually in the U.S. between 2011 and 2014, and the agency expects fracturing treatments to continue to be heavily relied upon in the future (EPA

2015). Therefore, the impacts were in no way "systemic" or "widespread".

EPA focused on hydraulic fracturing occurring near residences and drinking water resources, with approximately 9.4 million people living within one mile of a hydraulically fractured well between 2000 and 2013, and approximately 6,800 drinking water sources located within one mile of a hydraulically fractured well. EPA's assessment of the geographic area most likely to be affected by hydraulic fracturing yields a logical and quality sample set from which to form technical conclusions. As EPA acknowledges, if hydraulic fracturing was impairing drinking water resources, that evidence would manifest itself in these areas. EPA's finding of "no widespread, systemic effects" is founded on the state-of-the-science and a structured analytical methodology.

Table 1: Summary of Reviewed Literature Per HFWC Stage, Pathway for Chemical Migration, and Potential Effects

HFWC Stage	Pathway	Summary of Potential Effects	Finding(s) From Literature Review	Source(s)
Water Acquisition	While HVHF fluids do not have the potential to impair water resources at this stage, the hydraulic fracturing process relies on local water resources.	Imbalance between regional water supply and demand.	In 2005, the entire mining, oil and gas sector accounted for only 1 percent of the entire nation's water use, whereas electric power and agriculture accounted for 41 percent and 37 percent, respectively. The amount of water required for hydraulic fracturing can vary widely depending on the geology of the shale, the length of the horizontal well, and the number of fracturing stages performed. Across the nation, the volumes of water required range from 100,000 to five million gallons per well. Much depends on the context and condition of local/regional water resources.	Freyman and Salmon, 2013 Nicot et al., 2012 CDWR, 2012 Tormey et al., 2012 Abdalla and Drohan, 2010 Freyman, 2014 Tinker, 2012
Chemical Mixing	Spills of HF Fluids	Surface spills or spills that reach the subsurface of individual hydraulic fracturing chemicals or fracturing fluid (i.e., chemicals mixed with water for hydraulic fracturing).	The extraction of oil and gas requires surface activities that can lead to surface leaks or spills of oil or natural gas liquids, and any other chemical formulations used in the field. Risks associated with routine oil and gas operations have been addressed by state laws that provide regulatory protections for water resources and monitoring of the effectiveness of these controls. These concerns are not isolated to just wells that are proposed for hydraulic fracturing but oil and gas operations in general.	Krupnick and Olmstead, 2013 Lutz et al., 2013

Well Injection	Casing Failure and Legacy Wells	Migration of chemicals and natural gas/oil to groundwater sources as a result of improper well construction, well casing or cement failure under high pressure and/or repeated fracturing.	The well construction process uses a combination of multiple steel casings, cement sheaths, and other mechanical isolation devices to prevent the migration and transport of fluids between hydrocarbon producing formations and the groundwater layers. API and industry standards and best practices coupled with stringent regulations around such design and construction serve to promote well integrity and minimize potential for failures and consequent release of hydrocarbons to the environment.	King, 2012 API, 2009
	Fracturing into Underground Drinking Water Resources	Hydraulic fracturing fluids migrating to drinking water resources.	Well design and construction safeguards provide adequate protection to drinking water resources. These findings are corroborated in GAO's audit of EPA's management of the Class II underground injection program pursuant to the SDWA. Microseismic and micro-deformation mapping conducted on thousands of hydraulic fracturing jobs nationwide indicate that the growth of fractures vertically is relatively well-contained to the target shale zone, thousands of feet below potable water supplies.	GAO, 2014 Nottmeier, 2012 Fisher and Warpinski, 2011 ERCB, 2012 DiGiulio et al., 2011 EPA, 2004 Schug et al., 2013 Myers, 2012 Sloto, 2013 Kresse et al., 2011

	Liquids & Gases Migration	Migration of fluids through the hydraulically fractured network and/or the existing faults and fractures in the subsurface.	Within a wider regional context, methane is part of the natural condition and not caused by hydraulic fracturing. Studies have concluded that the thermogenic gases could not be attributed to gas wells or other anthropogenic activity. The oil and gas industry has developed well casing measures designed to minimize the flow of methane from depth to the surface. These measures include cement tests, well pressure tests (formation integrity and casing integrity), and magnetic tests for tubing integrity.	Molofsky et al., 2013 Warner et al., 2012 Kresse et al., 2012 Flewelling and Sharma, 2013 Jackson et al., 2013 ODNR, 2008 Baldassare et al., 2014
Flowback & Produced Water	Inadequate Treatment & Surface Discharge of Produced Water	Surface spills and releases of flowback and produced waters while transporting wastewater to or from storage tanks or impoundments containing constituents from the formation water (e.g., naturally occurring radioactive material, barium, dissolved solids, heavy metals and salts).	Produced water is generally characterized as brackish groundwater with elevated concentrations of TDS ranging from 1,000 mg/L to over 400,000 mg/L. Produced water can also contain naturally occurring radioactive materials (NORM) depending on the characteristics of the shale. Handling of NORM is undertaken in a controlled manner by industry and disposal sites and wells that are licensed to accept oil and gas waste d are monitored for radioactivity. The increased need for produced water management has led to innovations in water treatment technologies, particularly related to recycling for subsequent hydraulic fracturing, and the field is very active. In addition, the US Bureau of Reclamation is preparing a guidebook on the treatment and beneficial reuse of produced water.	King, 2012 Breit and Otton, 2002 Halusczak et al., 2012 Benko and Drewes, 2008 Krupnik and Olmstead, 2013 USBR, 2013

Wastewater Treatment & Disposal	Inadequate Treatment & Underground Disposal of Produced Water	Migration of produced water from improperly installed disposal wells, or directly into a drinking water resource.	An option for disposing of produced water is underground injection per EPA's UIC Class II program. A GAO audit of EPA's management of the Class II program found a very limited number of incidents impairing drinking water resources. Underground offers numerous benefits, including less treatment than other methods and creates the least risk of contaminating drinking water resources. Another option is produced water recycling/reuse. In 2011, 56 percent of wastewater was recycled for future well development. On-site recycling can have significant cost and environmental benefits by reducing water consumption, as well as the amount of wastewater requiring disposal.	GAO 2014 Hammer and Van Briesen, 2012 Haluszczak et al., 2012
	Lack of Infrastructure for Adequate Treatment & Discharge of Wastewater	Water treatment facilities (i.e., publicly owned treatment works and centralized waste treatment) may not be able to effectively treat wastewater from hydraulic fracturing activities, which can impact surface water when discharged.	In unconventional oil and gas development, the produced water cannot be injected back into the producing formation. It must be injected into another formation via disposal well; recycled for additional hydraulic fracturing; disposed of at a municipal or industrial water disposal facility; or treated for beneficial reuse. The available disposal options are permitted by state and federal programs, including Underground Injection Control permits under the Safe Drinking Water Act and National Pollutant Discharge Elimination System Permits under the Clean Water Act. These activities are regulated at the state level (or federal level on federal lands) by the agencies with primacy over water protection.	Lutz et al., 2013 Veil, 2010

	Spills of Produced Water	Spills to surface waters during transportation of wastewater to treatment facilities or disposal sites.	The extraction of oil and gas requires surface activities that can lead to surface leaks or spills of oil or natural gas liquids, and any other chemical formulations used in the field. Risks associated with routine oil and gas operations have been addressed by state laws that provide regulatory protections for water resources and monitoring of the effectiveness of these controls. These concerns are not isolated to just wells that are proposed for hydraulic fracturing but oil and gas operations in general.	Lutz et al. 2013 Krupnick and Olmstead 2013 Rozell and Reaven 2011

SUMMARY OF CASE STUDIES & RESEARCH

This section provides a brief summary of case studies and peer-reviewed literature addressing the relationship between hydraulic fracturing and water resources. The list is intended to be comprehensive, providing reports and studies published since EPA solicited input in developing the draft assessment in 2014. All of these studies support EPA's finding of no widespread, systemic effects to drinking water resources as result of hydraulic fracturing. For areas of high public interest (Dimock, PA; Parker County, TX; Pavillion, WY), a summary of related material is also presented to provide a greater context for the issues. An annotated bibliography summarizing each paper, as well as a summary description, are provided in **Appendix A**.

EPA's Assessment of the *Scale of Impacts*

EPA determined that at the scale of 25,000-30,000 new wells completed with hydraulic fracturing treatments annually, a limited number of incidents does not represent a "widespread, systemic" impact to drinking water resources. Further, EPA relies on quantitative data to assess the scale of impacts on the national, state, and county levels. EPA found that some instances occur at the local level (i.e. surface spills) but these incidents are very local and isolated and are not representative of a widespread effect. This report provides additional quantitative support at these scales, as well as more local, wellpad scales.

Hydraulic fracturing is typically conducted soon after a well has been drilled and is known as a completion process or stimulation treatment. Many studies and information from media outlets, however, use the term "fracking" to encompass the full life cycle of oil and gas production wells, not just the completion process of hydraulic fracturing (Figure 1). This confusion extends to considerations of the effects of hydraulic fracturing on water resources; it is often unclear whether a study refers to the completion process, or to the oil and gas well life cycle. The focus of this report is on the completion process of hydraulic fracturing and the HFWC (Figure 1), and considers the peer-reviewed literature, federal and state studies, and regulations and industry practices that address the potential impact of hydraulic fracturing on water resources.

Figure 2 depicts the active shale plays in North America, the volume of shale gas and shale oil estimated to be held in each, and the total number of studies conducted in each area since 2004, with the majority being published between 2012-2014 (dark circles on map). The majority of studies to date have been conducted in the Marcellus Shale region in the northeastern US. These studies are not necessarily applicable in their entirety to other shale plays, owing to differences in geology, the nature of the local water resources, and types of public interest. However, other more local studies across the country extend the applicability of the Marcellus studies. The quantitative basis for the EPA study comes from across the country, encompassing the range in conditions that may be encountered.

PATHWAYS FOR CHEMICAL MIGRATION

A variety of pathways have been proposed in the literature that could theoretically lead to drinking water quality impacts as a result of hydraulic fracturing operations, including migration of fracturing fluids through native fractures or extended fractures created during hydraulic fracturing, compromised well casing or cements during hydraulic fracturing, migration through nearby legacy or improperly abandoned wells, surface spills on the well pad locations, and transportation incidents. While these concerns occupy the public space, evidence (including from independent entities, EPA, and certain state government regulators) indicates that hydraulic fracturing of shale deposits is not directly linked to groundwater impairment. As in any other industrial activity however, surface spills can migrate and potentially affect water resources; robust regulatory frameworks and industry controls and sound operating practices are in place to minimize and/or mitigate this pathway.

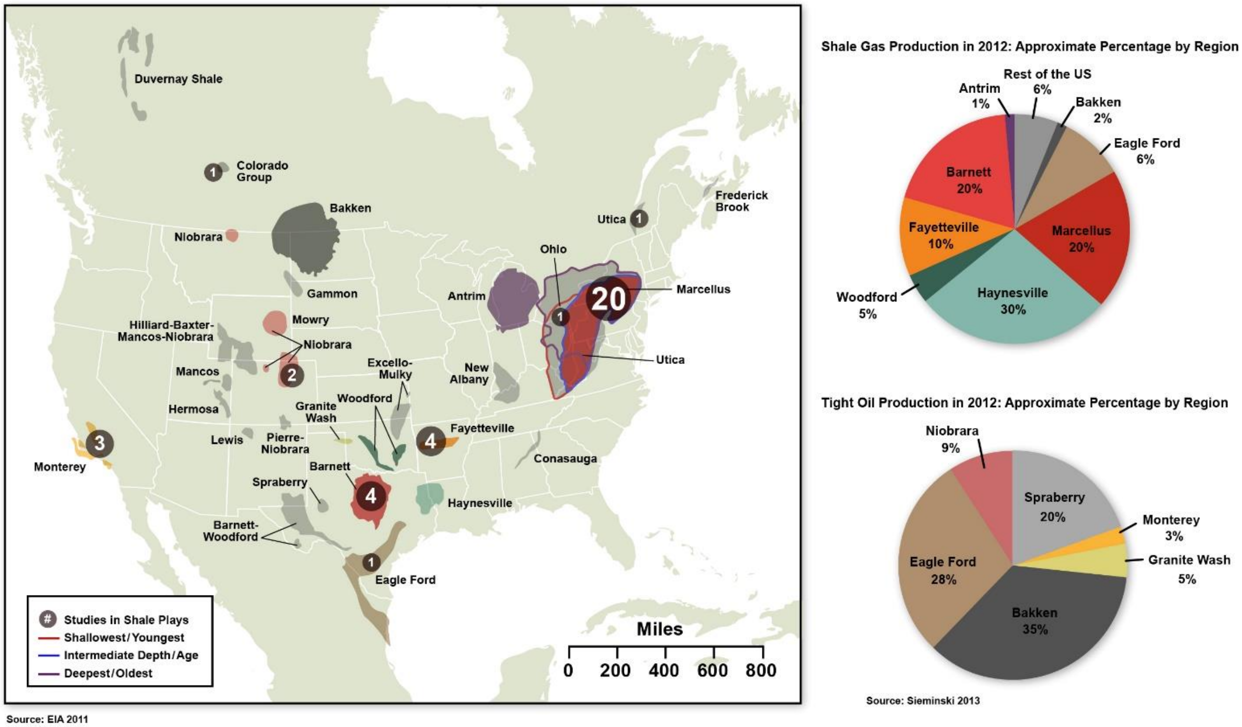

Figure 2 - Shale Play Areas and Associated Production of Shale Gas and Tight Oil in Comparison to Number of Published Studies

Shale gas and shale oil deposits tend to be deep: 2,000 feet to greater than 10,000 feet below the surface. The depth of potable groundwater varies across the country, but is generally 300 to 1,000 feet below the ground surface, when present at all. Thousands of feet of rock formations separate the targeted zones for hydraulic fracturing and the zones of fresh water supplies. Moreover, state regulatory programs have protocols requiring operators to identify the fresh water zones, provide for casing and cementing (zonal isolation) of those zones and well construction requirements that provide assurance that the targeted production zones will not impact shallow potable water supplies.

Microseismic and micro-deformation mapping has been conducted on thousands of hydraulic fracturing events nationwide, which document that the growth of fractures vertically is relatively well-contained to the target shale formation at depth. Moreover, casing failures in new wells also has not been supported as a pathway for migration by recent studies. The relatively short duration of elevated pressure during a hydraulic fracturing stage (approximately one hour) makes legacy and improperly abandoned wells located next to the hydraulically fractured well the only plausible pathway for chemical migration to fresh water zones.

In addition to potential subsurface pathways associated with hydraulic fracturing, some studies include pathways associated with conventional oil and gas development activities. The surface pathways include leaks and spills from impoundments, tanks, and other surface infrastructure, and issues associated with wastewater disposal. Although these surface pathways are not strictly within the scope of a review of the effects of hydraulic fracturing and water quality, they are discussed briefly because they do occur within the literature of hydraulic fracturing, and studies generally indicate that the existing regulatory framework is adequate to address these concerns.

Figure 3 depicts the potential pathways for contaminant migration that have been presented in the literature, and some of the existing protections in place, enforced by local, state and federal regulations, as well as industry standard operating procedures. The scale of the figure suggests a much closer proximity of target shale zones are water supplies than is typically the case; the schematic figure is intended to summarize the concerns and protections.

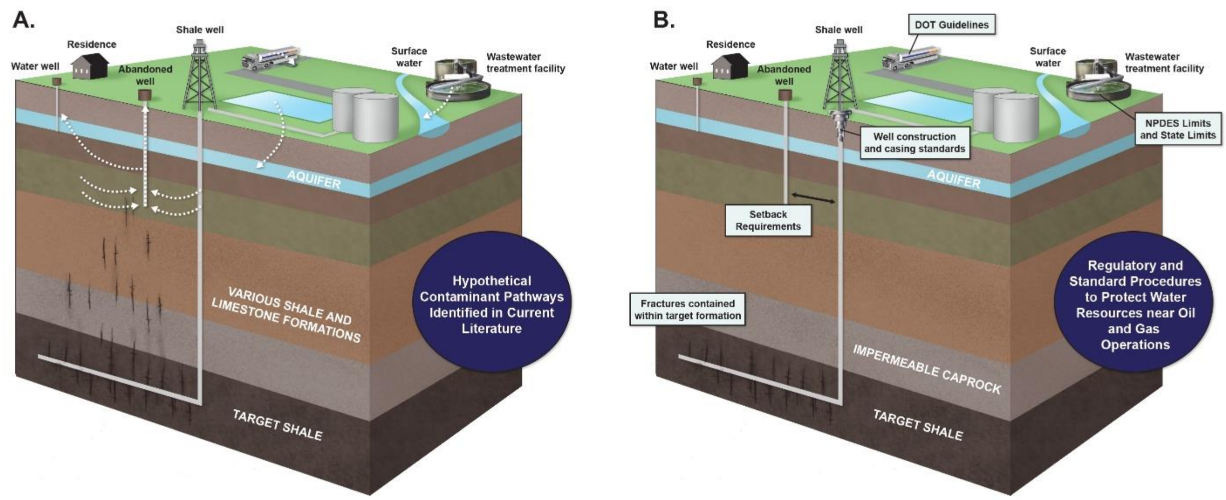

Figure 3 - Depiction of Hypothetical Contaminant Pathways and Associated Protections for Water Resources

Fractures Restricted to the Target Shale Zone

Microseismic and micro-deformation mapping conducted on thousands of hydraulic fracturing jobs nationwide (Fisher and Warpinski 2011) indicate that the growth of fractures vertically is relatively well-contained to the target shale zone, thousands of feet below potable water supplies. Figure 4 is taken from Fisher and Warpinski (2011) and depicts the depth and vertical height affected by hydraulic fracture jobs conducted in the Barnett Shale of Texas (inclined multi-colored lines), compared to the depth of water (blue horizontal line at top of chart). The physical constraints of upward fluid migration through fractures in the Marcellus, Bakken, and Eagle Ford shales are also discussed in Flewelling and Sharma (2013). This study discusses the short duration and localized pressure caused by hydraulic fracturing, followed by the depressurization initiated by bringing a well onto production which makes the possibility of pressure propagation and the displacement of natural brines highly unlikely; after a hydraulic fracturing simulation the hydrocarbon extraction processes draws fluid *toward* the target formation.

Fracture lengths of a typical hydraulic fracture operation can sometimes exceed 1,000 feet horizontally within a shale zone; the vertical zone fractured is typically much smaller because of the layered geological environment acting as a control on vertical growth (Warpinski et al. 2001).

A study in the Fayetteville Shale, with shallower shale deposits, suggests that the potential for migration of fracturing fluids increases when the distance between the shale and the freshwater zones is shorter (Kresse et al. 2011). However, the shale formation is still separated from groundwater by thousands of feet, and as of 2012 when the study was conducted; there are no known cases of communication between hydraulic fracturing and freshwater aquifers (King 2012).

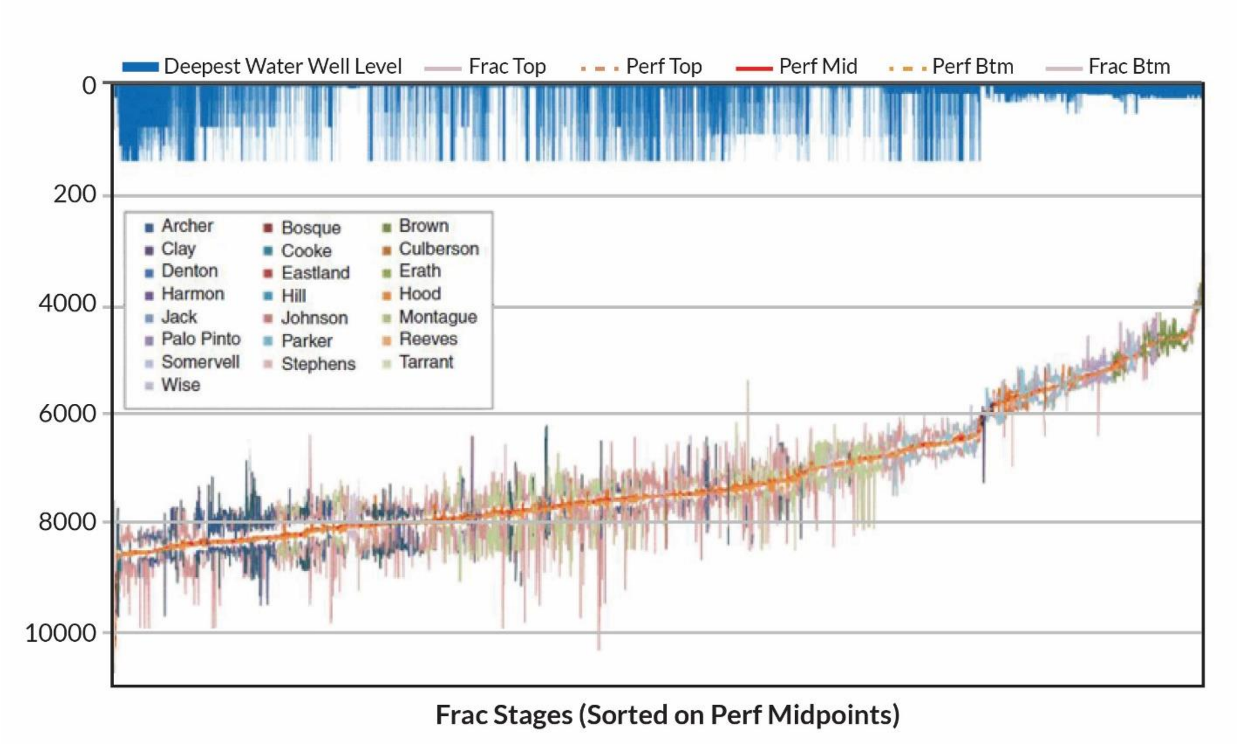

Figure 4 -Depth and Vertical Height of the Formation Affected by Hydraulic Fracturing Operations Conducted in the Barnett Shale (Fisher and Warpinski 2011)

Casing Failure and Legacy Wells

The well construction process uses a combination of multiple steel casings, cement sheaths, and other mechanical isolation devices to prevent the migration and transport of fluids between hydrocarbon producing formations and the groundwater layers (King 2012). API and industry standards and best practices coupled with stringent regulations around such design and construction serve to promote well integrity and minimize potential for failures and consequent release of hydrocarbons to the environment (API 2009). Further, casing pressure and well integrity is monitored prior to and during each stage of hydraulic fracturing operations. The well casing is tested to ensure integrity prior to injection of fracturing fluids.

Fractures created during hydraulic fracturing have the potential to intersect an abandoned or improperly plugged oil or gas well, which could lead to the upward migration of fracturing fluids or brines through the old well. These are a possibility in areas that have seen oil and gas production for many years. As such, operators typically evaluate proximity to older wells to ensure that the hydraulic fracturing job is successful and stays within the target zone. Were such a pathway to occur, it would create a noticeable pressure drop in the well undergoing hydraulic fracturing treatment and would prompt appropriate inquiry (King 2012).

Leaks and Spills

The extraction of oil and gas requires surface activities that can lead to surface leaks or spills of oil or natural gas liquids, and any other chemical formulations used in the field. Risks associated with routine oil and gas operations have been addressed by state laws that provide regulatory protections for water resources and monitoring of the effectiveness of these controls. These concerns are not isolated to just wells that are proposed for hydraulic fracturing but oil and gas operations in general.

EPA identifies the three primary times during which chemicals can spill to the surface as: (1) on-site chemical storage, (2) chemical mixing, and (3) chemical pumping into the target well. The primary causes for surface spills are equipment failure, container integrity failure, and human error, causing 34%, 11% and 25% of spills, respectively. EPA highlights the following as common causes of chemical spills.

- Complex, interconnected systems with a number of components are more likely to have spills because there are many connection points, where equipment failure is most likely to occur. In addition, human error is most likely to occur when assembling these complex, multipart systems.
- Older equipment is more likely to fail. Moreover, repeated and prolonged stress from the high pressure injection of abrasive fluids can lead to equipment failure. Curved sections of flow lines are particularly susceptible to corrosion and cracks as abrasive materials are forced through them at high pressures.
- Excessive flow rate variation during well treatment can cause the chemical blender to malfunction or shut down, potentially resulting in spills. And if flow pressure is not maintained then proppants may settle out, damaging pumps and increasing the potential for spills.

Considering that human error and equipment failure are the primary causes for hydraulic fracturing fluids contacting drinking water resources, EPA correctly concluded that surface spills of hydraulic fracturing fluids do not represent a widespread or systemic effect to drinking water resources. Hydraulic fracturing chemicals are tightly managed by industry operating practices and safe handling procedures, limiting the potential for surface spills. These local incidents are unpredictable and occur only when a treatment does not go as planned; leading EPA to correctly assess that there is not a direct correlation between hydraulic fracturing and water resources impairment.

Produced Water Handling and Disposal

Flowback water returns to the surface immediately after hydraulic fracturing, and can contain up to 30 percent of the chemicals injected along with the water and sand mix. In contrast, produced water is extracted along with the oil and gas, with the volume varying over time. Produced water is also part of development of conventional sources of oil and gas, and is not specific to hydraulic fracturing.

Because produced water is in contact with hydrocarbons and geologic formations in deep underground basins, it usually contains elevated concentrations of inorganic and organic constituents. A 2008 study by the US Geologic Survey characterized produced waters, with a focus on the western U.S. (Benko and Drewes 2008). The study contains the major ion analysis and total dissolved solid concentration (TDS) for water from 58,706 oil and gas wells (primarily from conventional oil and gas operations) from the mainland U.S., Alaska, and offshore (Breit and Otton, 2002, as cited in Benko and Drewes 2008). Produced water is generally characterized as brackish groundwater with elevated concentrations of TDS ranging from 1,000 mg/L to over 400,000 mg/L. Produced water can also contain naturally occurring radioactive materials (NORM) depending on the characteristics of the shale. Handling of NORM is undertaken in a controlled manner by industry and disposal sites and wells that are licensed to accept oil and gas waste are monitored for radioactivity (King 2012).

In unconventional oil and gas development, the produced water cannot be injected back into the producing formation. It must be injected into another formation; recycled for additional hydraulic fracturing; disposed of at a municipal or industrial water disposal facility; or treated for beneficial reuse. The available disposal options are permitted by state and federal programs, including Underground Injection Control (UIC) permits under the Safe Drinking Water Act and National Pollutant Discharge Elimination System (NPDES) Permits under the Clean Water Act. These activities are regulated at the state level (or federal level on federal lands) by the agencies with primacy over water protection.

The increased need for produced water management has led to innovations in water treatment technologies, particularly related to use of produced water and recycling for subsequent hydraulic fracturing, and the field is very active. In addition, the US Bureau of Reclamation is preparing a guidebook on the treatment and beneficial reuse of produced water (USBR 2013).

Hydraulic Fracturing Additives

Chemical additives used in hydraulic fracturing typically comprise about 0.5 percent of the total fluids used and are necessary to ensure that the process is as effective and efficient as possible. Many of the additives are components of common domestic use products and have also been in use in the industry safely. These additives include corrosion inhibitors to protect the well, and biocides to limit well fouling by bacterial growth. Some additives are used to cause the water to gel in order to hold the proppants in suspension, and hydrocarbons are used to reduce the viscosity of the mixtures.

Most states have enacted regulations for the disclosure of chemicals used in the hydraulic fracturing process, typically through the FracFocus (www.fracfocus.org) chemical registry, a database and website initiated by the Groundwater Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC). Although most of the compounds are either in routine use in the oil and gas industry, or are commonly used in other industries, not all have undergone full, formal characterization. This is an area of innovation in the industry, seeking to identify and use chemicals that reduce the toxicity and impact of chemical additives used for hydraulic fracturing. FracFocus continues to be an “evergreen” tool, adapting to regulatory requests for search capabilities and other requirements to address external stakeholder requests.

Methane in Groundwater

Methane (CH_4) is a naturally occurring gas widely distributed throughout the U.S. Methane forms in several different environments, both shallow and deep. Biogenic methane is primarily methane with carbon dioxide and sulfide gases that result from decomposition of organic material, such as from former marshy areas (swamp gas) or from sewers. Although biogenic gas contains mostly methane and carbon dioxide, these gases also consist of lesser amounts of ethane, propane, and butane, as well as trace amounts of hydrogen sulfide and ammonia. Thermogenic methane is generated at depth when increased temperatures and pressures alter organic material to form gases. Thermogenic gas contains a broader range of gas components than biogenic, including methane, ethane, propane, and butane, as well as trace amounts of hazardous gases, including hydrogen sulfide. These different types of methane can typically be distinguished based on the isotopic composition of hydrogen and of carbon in the methane (Figure 5).

Beginning in 2011, studies have been conducted to address public concerns that hydraulic fracturing activities have contributed to the detection of methane in public drinking water supplies and private groundwater wells. Frequently missing from discussions of water quality is the fact that methane in water is not toxic; for this reason, there is no established primary or secondary drinking water standard. There can be a physical hazard associated with methane in water, if it is present in quantities that can lead to its accumulation in confined spaces, where it can become flammable. The US Office of Surface Mining Reclamation and Enforcement considers 28 mg/L in a water supply well as indicative that action be taken to reduce the concentration before use. Concentrations below 10 mg/L are considered safe, and between 10 and 28 mg/L the US Office of Surface Mining Reclamation and Enforcement suggests monitoring. The US Bureau of Land Management also lists 10 mg/L as a safe concentration.

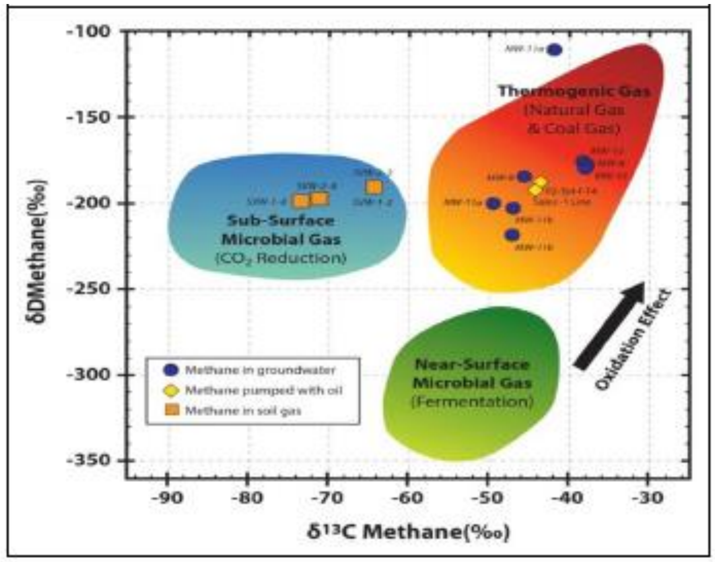

Figure 5 - Isotopic Composition of Different Types of Methane

Studies conducted by researchers at Duke University in 2011 and 2013 found a correlation between the presence of methane in private drinking water wells in and around Dimock, Pennsylvania, and the location of the well in relation to hydraulic fracturing operations. The primary concern with these studies is that no data was collected prior to hydraulic fracturing, and as such, there is no measurement of the natural background level of methane. In a study responding to the question of background levels of methane in groundwater, Molofsky (2011) found that higher concentrations of methane were observed in water wells located in valleys than those wells in higher upland areas. This study and a subsequent report (Molofsky, et al. 2013) shows that, with a wider regional context, the methane is part of the natural condition and not caused by hydraulic fracturing. The review of historical, topographical, and geological data by the authors suggest that the methane is thermogenic in nature, most likely originating in the deposits overlying the Marcellus Shale or biogenic, microbial, methane resulting from the long residence time in anaerobic groundwater units. Baldassare et al. (2014) also conclude that the thermogenic gases could not be attributed to gas wells or other anthropogenic activity.

Recent isotopic analysis indicates that the source of the methane in the Marcellus region may be the geological formations that overlie the Marcellus Shale, without any contribution from hydraulic fracturing in the Marcellus Shale (Molofsky 2011, Baldassare et al. 2014). This further supports the finding that the methane in groundwater is a natural feature of the area. Studies in the Fayetteville Shale and the Barnett Shale did not find correlations between methane content and proximity to gas wells, and did not find increased levels of methane in water compared to baseline conditions.

Some areas, such as the City of Los Angeles and western Pennsylvania, are known to have high levels of methane at shallow levels; some is naturally-occurring, and some is due to older wells (Geoscience 1986). Well integrity management addresses this issue through monitoring and triggers for re-abandoning older wells if necessary. In California, this program is overseen by the California Department of Oil, Gas, and Geothermal Resources (DOGGR).

The oil and gas industry has developed well casing evaluation methods/tools designed to minimize the flow of methane from depth to the surface, including cement tests, well pressure tests (formation integrity and casing integrity), and magnetic tests for tubing integrity. Well integrity is an area of active analysis and improvement within the industry, and also receives a high degree of attention from state oil and gas regulatory authorities.

Water Supply and Quantity

The amount of water required for hydraulic fracturing can vary widely depending on the geology of the shale, the length of the horizontal well, and the number of fracturing stages performed. Across the nation, the volumes of water required range from 100,000 to five million gallons per well (Freyman and Salmon 2013; Tormey, et al. 2012). One commonly used metric to assess water use for energy production is energy water intensity, which measures the volume of water used per unit of energy produced. The water intensity of shale gas is relatively small when compared to other energy sources. Further, research has suggested that shifting energy sources from a coal-fired power plant to natural gas saves 25 to 50 times as much water as the amount used in hydraulic fracturing (Scanlon et al 2013). In 2005, the entire mining, oil and gas sector accounted for only 1 percent of the entire nation’s water use, whereas electric power and agriculture accounted for 41 percent and 37 percent, respectively (Kenney 2009). Similarly, electric generation uses nearly 150 million gallons a day in the Susquehanna River Basin, while the projected total demand for peak Marcellus Shale oil and gas activity in the same area is 8.4 million gallons per day (Fracfocus.org). The percentages are variable at the local scale: for example, water used for hydraulic fracturing in Wise and Johnson counties in Texas’ Barnett shale represented 19 and 29 percent of the counties’ respective total water use (Freyman and Salmon 2013).

A combination of factors determines whether hydraulic fracturing introduces imbalance in the relationship between water supply and demand in a region, including drinking water resources. These factors include available water resources and their capacity to yield water, industry needs influenced by geologic characteristics of rocks in each play, other user demands, and permitting or allocation controls. A comparison of these factors in the Susquehanna River Basin in Pennsylvania and the Upper Colorado River Basin found that there were minimal impacts to past or present drinking water supplies or other water users resulting from hydraulic fracturing water acquisition were found in either study basin due to unique combinations of these factors in each area. In the Susquehanna River Basin in Pennsylvania there is little use of public water supplies (currently <8%) because water resources are well distributed and available year-round and hydraulic fracturing operators have been able to develop unallocated sources. In this basin, there are times or locations when water sources can be stressed, but water is managed to prevent overuse and minimize risk at individual sources.

In contrast, water in the Upper Colorado River Basin in Colorado is strongly seasonal and over-allocated, but unconventional gas production requires little freshwater as the industry is able to reuse large volumes of flowback and produced water instead. No municipal drinking water supplies are used for hydraulic fracturing in the areas studied within the Upper Colorado River Basin.

In addition to the overall quantity of water needed for hydraulic fracturing, it is important to consider the water source, which varies from region to region, as well as the general availability of water in the region (Figure 6). Many states have old and complex water rights systems, complicating the ability to obtain water for hydraulic fracturing. For example, in Colorado, the water rights are based on the prior appropriation doctrine, which states that water extracted from a river must be reconciled with the prior appropriation system. A study prepared by the Colorado Division of Water Resources, the Water Conservation Board, and the Oil and Gas Conservation Commission outlines a variety of potential water sources for hydraulic fracturing operations. The list (COGCC 2012) was developed specifically for Colorado but the following water source options are applicable across multiple regions:

- Water transported from across state lines;
- Irrigation water leased from a landowner;
- Water purchased from a water provider;
- Water treated and released from a wastewater treatment plant;
- New diversion of surface water;
- Groundwater diverted from wells;
- Produced water; and,
- Recycled construction water.

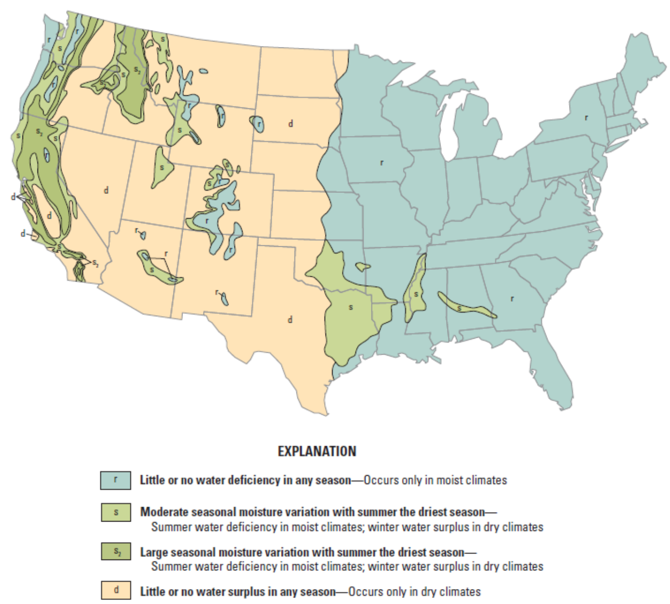

Figure 6. Depiction of Water Availability Across the U.S. and Water Supplies (Reilly et al. 2008)

A review of the literature indicates that water for hydraulic fracturing can come from a variety of these sources. For example, at an oil field located in the Los Angeles Basin, water for the hydraulic fracturing operations was provided either from produced water at the field or, if a potassium-chloride gel is used, fresh water provided by a local retail water service provider. The local water service provider, in turn imports water from the Colorado River or from the San Joaquin Delta in Northern California; very limited supplies of water are pumped from local groundwater supplies (Tormey, et al. 2012). In contrast, the majority of water used for hydraulic fracturing in the Marcellus Shale is withdrawn from local surface water bodies. For example, between 2008 and 2011 approximately 700 million gallons of water were withdrawn for hydraulic fracturing in the Susquehanna River Basin, of which approximately 70 percent came from surface water sites and the remaining 30 percent came from the public water supply (Abdalla and Drohan 2010).

In the Permian Basin of Texas, nearly all of the water used is groundwater because the Ogallala and other aquifers provide ample supplies of freshwater. The majority of the water used from hydraulic fracturing in the Texas portion of the Haynesville Shale is fresh groundwater (approximately 70 percent of the "new" water). In the Barnett Shale, in contrast, operators use primarily fresh surface water (representing 80 percent of all of the freshwater). Finally, in the Anadarko basin, approximately 50 percent of the water used is recycled water or brackish water (Tinker 2012).

The trend of water use is towards greater amounts of recycled water. As hydraulic fracturing matures in each shale basin, the optimum mix of additives becomes standard. At this point, recycled water can be more readily used. In the Marcellus, up to 97 percent of the water is recycled.

Distinctions Between the Regions

The different shale plays exhibit variability in geology, hydrology, hydrogeology, and land use. Some of this variability is seen in:

1. Separation between shale plays and aquifers
2. Water quality concerns
3. Water quantity concerns

Figure 7 provides a summary of the differences in distance between the base of the drinking water aquifer and the average top of the producing formation in the different shale play areas. In areas with a smaller separation between shale play and aquifers, the level of concern related to water quality increases.

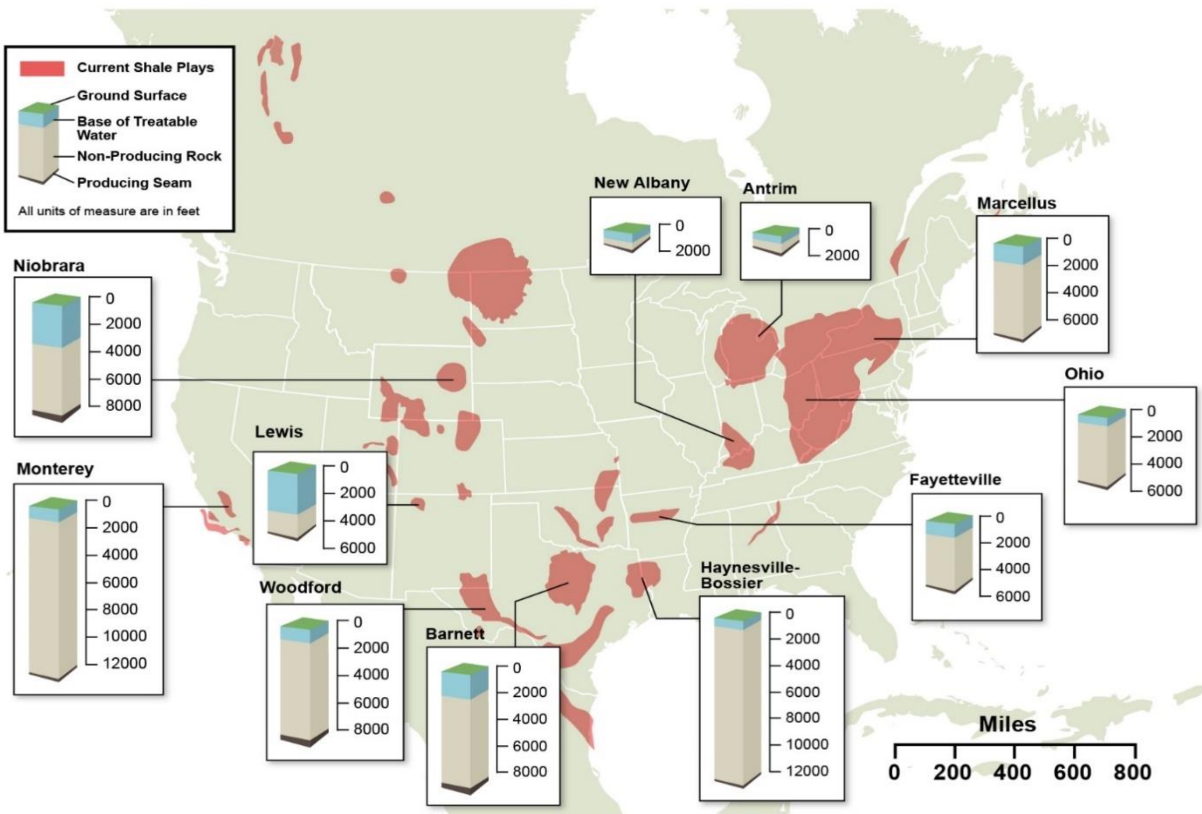

Figure 7 - Separation between Target Shale and Drinking Water Sources

Water quality tends to be the greatest concern east of the Mississippi River. Water quantity tends to be plentiful in this region, but many dwellings receive water from private drinking water wells. The private drinking water wells do not require periodic sampling, and the construction requirements for these wells are less protective than for public supply wells. As such, the level of concern with the effects of hydraulic fracturing on water quality tends to be higher. These areas also tend to lack baseline data regarding conditions prior to hydraulic fracturing.

West of the Mississippi River, water quantity tends to be a greater concern than water quality. Periods of drought and competition for water supply with public consumption and agriculture affects the perceived level of impact of use of large quantities of water for hydraulic fracturing.

Despite these geographic variations, the literature on the relationships between hydraulic fracturing and water resources is sufficient to address each theme. Published studies are concentrated in the Marcellus Shale region, but the studies which followed in other regions were informed by these data and studies were designed to address the same issues, as well as the specific issues in the different regions.

SECTION 3

Other Recent Comprehensive Reviews Support EPA's Conclusions

State and federal reviews were produced in 2014 and 2015 that had a similar mandate to EPA's: to evaluate the potential effects of hydraulic fracturing to drinking water resources, and other environmental resources. The most comprehensive is that of the California Council on Science and Technology (CCST), which studied the effects of well stimulation (focusing on hydraulic fracturing) in California for the US Bureau of Land Management (BLM; CCST 2014) and the state of California Department of Conservation (CCST 2015). CCST concluded that the direct effects of hydraulic fracturing appear small, and that good management and mitigation measures can address the vast majority of potential direct impacts of well stimulation. These studies and programs provide quantitative support to EPA's finding that hydraulic fracturing did not lead to widespread, systemic impacts to drinking water resources.

CALIFORNIA COUNCIL ON SCIENCE AND TECHNOLOGY

California law Senate Bill 4 (SB-4) required an independent study to assess current and potential future well stimulation practices in California, including the likelihood that these technologies could enable extensive new petroleum production in the state; impacts of well stimulation technologies (including hydraulic fracturing, acid fracturing and matrix acidizing); gaps in data that preclude evaluation; potential risks associated with current practices; and alternative practices that might limit these risks. CCST organized and led the study, where members of the CCST steering committee were appointed based on technical expertise and a balance of technical viewpoints. Under the guidance of the steering committee, Lawrence Berkeley National Laboratory (LBNL) and subcontractors (the science team) developed the findings based on original technical data analyses and a review of the relevant literature. The science team and the steering committee collaborated to develop a series of conclusions and recommendations that are provided in the summary report.

SB 4 also required the participation of the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) in the study. OEHHA provided toxicity and other risk assessment information on many of the chemicals used in hydraulic fracturing, offered informal technical advice during the course of the study, and provided comments. The report had extensive peer review. Eighteen reviewers were chosen for their relevant technical expertise. More than 1,500 anonymous review comments were provided to the authors. Report monitors, appointed by CCST, then reviewed the response to the review comments and when satisfied, approved the report.

On July 9, 2015, CCST issued the report on the effects of hydraulic fracturing and other well stimulation technologies across California. It included a long, 3-volume report of over 2,000 pages, and the steering committee summary report intended for policy makers and members of the public and interested in this topic. The CCST steering committee members were appointed based on a spectrum of relevant technical expertise and a balance of technical viewpoints, and included experts in hydrology, chemistry, petroleum geology, petroleum engineering, public health, risk analysis, seismology, and ecology. A science team led by LBNL and the steering committee collaborated to develop a series of conclusions and recommendations on the questions posed by the legislature to assess current and potential future well stimulation practices in California, including the likelihood that these technologies could enable extensive new petroleum production in the state; impacts of hydraulic fracturing; gaps in data that preclude evaluation; potential risks associated with current practices; and alternative practices that might limit these risks.

Publicly available information indicates the vast majority of hydraulic fracturing occurs in four oil fields in the San Joaquin Valley. California's experience with hydraulic fracturing differs from that in other states because California wells tend to be shallower and the reservoirs more permeable. California operators generally do not conduct high-volume hydraulic fracturing from long-reach horizontal wells, and for this reason use far less water. Much larger volumes of water are produced as a byproduct of oil production and used for injection into reservoirs during enhanced oil recovery. There could be major opportunities for water conservation, efficiency and reuse; however, these benefits relate to all of oil and gas production, not just hydraulically fractured wells.

Direct impacts of hydraulic fracturing stem from unrestricted and/or mismanaged chemical use. These appear small but have not been systematically investigated. Significant gaps and inconsistencies exist in available voluntary and mandatory data sources that limit assessment of the impacts of hydraulic fracturing. However, good management and mitigation measures can address the vast majority of potential direct health and environmental impacts of well stimulation including hydraulic fracturing. Although no adverse effects have been demonstrated, the study recommended that, as a precautionary measure, the state should disallow the use of any chemical with unknown environmental effects and work with industry to "limit the use of hazardous and poorly understood chemicals" per Recommendation 3.2 of the CCST study (2015).

Like the EPA study, the CCST study found no documented instances of hydraulic fracturing or acid stimulations directly causing groundwater impairment in California. However, because fracturing in California tends to be in shallow wells and in a few locations, hydraulic fractures could possibly intersect protected groundwater, mostly in the San Joaquin Valley. The CCST report recommended that the State should investigate these sites to see if impairment has occurred and develop a regulatory approach to managing them. LLNL and the State Water Resources Control Board followed this recommendation, and developed a robust groundwater monitoring protocol that is now required prior to the issuance of a permit to conduct hydraulic fracturing in the state; while the State and EPA are jointly evaluating the possible occurrence of injection into protected aquifers.

The CCST study then evaluated indirect effects of hydraulic fracturing; that is, the impact of increased oil and gas production enabled by hydraulic fracturing. For example, oil and gas development in general causes habitat loss and fragmentation that should be mitigated and, near any production well, emissions may cause local concentrations of hazardous contaminants that could affect the health of nearby citizens. The effects were not specific to hydraulic fracturing. The CCST report makes reference to regulations where appropriate, but the authors did not perform a comprehensive analysis of regulatory adequacy to address these issues. Instead, where potential impacts were identified, the report recommended that the agency with jurisdiction over the impact determine whether the regulatory regime was adequate to address it.

SECTION 4

Industry Practices and State Regulatory Frameworks Protecting & Monitoring Drinking Water Resources

This section discusses industry practices, and the federal and state regulations that have been developed to minimize the potential for chemical migration and impairment of drinking water. EPA's finding of no widespread, systemic effects to drinking water resources from hydraulic fracturing is a reflection of the effectiveness of industry practices and regulatory frameworks in protecting this resource. It makes sense that the EPA would come to the conclusion it did, given the many measures and best practices implemented by oil and gas companies to ensure the protection of drinking water resources. This topic is addressed at length in the October 2016 report prepared by Catalyst Environmental Solutions entitled ***Industry Practices and Trends Protecting Water Resources during Hydraulic Fracturing: Information for US EPA's Draft Assessment.*** The reader is referred to that report for greater detail.

Agencies developed these regulations and policies with a strong understanding of the causative mechanisms of how hydraulic fracturing could impair drinking water resources, as discussed in Section 2 above. The common theme in both the federal and state level regulatory frameworks is *prevention* of an incident through the assignment of well design/construction and equipment safeguards that specifically target the causative mechanisms. These preemptive measures are a key contributing factor to the limited number of recorded drinking water resource impairments resulting from hydraulic fracturing.

EPA is justified in its position to let the new information prove out its finding and amend the regulations based on the issues identified through the state-of-the-science. Both federal and state regulatory frameworks, as well as industry operating practices, are still evolving as new information sources come on line. These new data sources provide the basis for an adaptive regulatory approach to refine rules and guidance on top of an already successful strategy focused on incident prevention. For example, many of the states where hydraulic fracturing is occurring have initiated groundwater testing and/or monitoring programs as a condition of permit issuance. Eleven major oil and gas producing states have implemented baseline and on-going water quality monitoring programs, including California, Colorado, Wyoming and Pennsylvania. Collectively, states with water quality monitoring programs represent 30 percent of oil and gas production in the U.S. (EIA 2016). Collectively, these programs are providing comprehensive and proof positive information that hydraulic fracturing is not leading to widespread, systemic effects to drinking water resources. For example, a comprehensive monitoring program has just been initiated in California, developed from the results of the study by the CCST, and adopted by the state as a regulatory requirement.

State governments have also initiated independent analyses of the potential environmental impacts of hydraulic fracturing. Where there are regulations specific to hydraulic fracturing, the focus is on water quality, chemical disclosure, and public notification. In addition, numerous U.S. federal and state laws and regulations establish requirements and expectations for safeguards against potential environmental impacts of all aspects of oil and gas development, including hydraulic fracturing.

SUMMARY OF STATE REGULATIONS

EPA has generally delegated primacy of a number of federal regulatory programs to the states for the implementation and enforcement of a broad range of environmental regulations which are applied to oil and natural gas development. Moreover, extensive state regulations provide tailored requirements governing the development of oil and natural gas resources and protection of water resources. State oil and gas regulatory agencies routinely initiate reviews of their regulatory programs in response to changing industry practices and technology. Given the potential environmental impacts of hydraulic fracturing from the growing number of unconventional developments, many state oil and gas regulatory agencies undertook regulatory reviews and technical studies and initiated rulemakings to propose, adopt and implement modifications to their existing regulatory frameworks governing oil and gas development.

SAB identifies that lack of discussion of relevant state regulations as a weakness of the Draft Assessment suggests that the EPA Final Assessment provide a more detailed discussion and analysis of state regulations governing hydraulic fracturing, stating "The EPA should consider reviewing hydraulic fracturing-related standards and regulations within a few key states such as Pennsylvania, Wyoming, Texas, Colorado, and California, which all have implemented new hydraulic fracturing-related regulations since 2012. The EPA could consider the work completed on this topic by the IOGCC, the State Review of Oil, Natural Gas, Environmental Regulations, Inc. (STRONGER) organization, and the Groundwater Protection Council (GWPC)."

This section provides detailed summary of regulations pertaining to hydraulic fracturing and water resources at the state level. The variations in regulations pertaining to hydraulic fracturing between the states is both a product of the level of oil and gas activity and hydraulic fracturing activity in each state, and the specific geology of the formations and drinking water aquifers in each state. The states with the greatest amount of oil and natural gas production have the most comprehensive regulations for industry activity as a whole, including well installation, completions, drilling, and operation. Specific regulations pertaining to hydraulic fracturing are those that are in addition to the regulations already enforced for oil and gas activity in each state.

Table 3 lists the top five oil and natural gas producing states in the U.S. based on annual data from the U.S. Energy Information Administration. As shown in the table, the top five oil producing states in the United States, Texas, North Dakota, California, Alaska, and Oklahoma, account for over 75 percent of all oil production in the nation. Texas is also the number one producer of natural gas in the U.S. followed by Pennsylvania, Oklahoma, Louisiana and Wyoming, which together account for 66 percent of the natural gas production. These states also account for the majority of hydraulic fracturing operations in the U.S., along with Colorado, Utah, and New Mexico. Corroborating the geography of where hydraulic fracturing is being most used, EPA also determined that the top 10 states experiencing the most hydraulic fracturing are: Arkansas, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming (EPA 2015).

Table 3 - States with the Greatest Oil and Natural Gas Production in the United States (EIA 2014)

Top Oil Producing	Volume	Top Natural Gas	Volume

States	(1,000 barrels)	Producing States	(million cubic feet)
Texas	1,158,166	Texas	7,178,225
North Dakota	394,468	Pennsylvania	4,217,704
California	204,699	Oklahoma	2,161,221
Alaska	181,175	Louisiana	1,923,168
Oklahoma	145,454	Wyoming	1,717,470
New Mexico	123,821	Colorado	1,558,289
Colorado	95,787	Arkansas	1,122,151

In Texas, the state ranked #1 in both oil and natural gas production in the United States, all wells that are drilled require casing to be set below the depth of usable groundwater and individual analyses are done for each proposed well to determine the specific groundwater protection depths. In addition, there are strict well construction requirements requiring several layers of steel casing and cement. In addition, the geology in Texas is such that hydraulic fracturing typically occurs one mile or more below drinking water aquifers; freshwater zones vary throughout the Barnett Shale region from the surface to a depth of 2,000 feet, compared to the shale zone targeted for hydraulic fracturing which occurs 6,000 to 7,500 feet below ground. Similarly, in the Eagle Ford shale, the Carrizo Aquifer is found from the surface to a 6,000-foot depth, while 3,000 to 8,000 feet of isolating layers of rock is found between the aquifer and the zone that is undergoing tight shale hydraulic fracturing at depths of between 8,000 and 15,000 feet. Similarly, in Oklahoma which is a top producer of both oil and natural gas, thousands of feet separate the areas of hydraulic fracturing from drinking water aquifers and the state maintains strict well construction requirements for all wells. Rules specifically related to hydraulic fracturing require disclosure of chemical use, but all non-domestic surface and groundwater use requires a permit from the Oklahoma Water Resources Board. Therefore, any oil and gas operation in the State, including those proposing hydraulic fracturing, would be required to obtain a provisional temporary 90-day permit for water use from the state agency.

Both North Dakota and Pennsylvania require baseline groundwater quality analyses. North Dakota oil and gas rules also provide protections for landowners from groundwater contamination from all subsurface operations for all landowners with surface or groundwater rights within one mile of any oil and gas well, rather than regulations specific to only operations including hydraulic fracturing. North Dakota regulations also include specific casing and pressure monitoring requirements for hydraulic fracturing operations, in addition to the requirements applicable to all oil and gas wells. In the consideration of all drilling permits, North Dakota considers the location of the proposed well and depending on the proximity to military installations, wellhead protection areas, etc. the operator is required to notify the North Dakota Department of Health, the applicable military installation or county or township of the proposed well operations. In Pennsylvania, Act 13, enacted in 2012, represented a major update to the states oil and gas operations and provides specific regulations for operators conducting natural gas operations in the Marcellus shale. The act includes specific permitting provisions for unconventional wells, along with notification requirements, baseline groundwater analyses, and provisions for liability for any impacts to water quality, as well as significantly increase permit fees and water quality standards for discharged water to drinking water standards.

California and Alaska are ranked #3 and #4 in oil production in the United States and both have recent, comprehensive regulations specific to hydraulic fracturing which require chemical disclosure, baseline water quality sampling and groundwater monitoring following hydraulic fracturing. In California, where water supply is a major concern (as compared to Alaska where water is plentiful), an analysis of the source of water used in hydraulic fracturing is also required (see inset on California for more information). Both states also require landowner notification prior to hydraulic fracturing.

In Louisiana, a state with heavy hydraulic fracturing activity and ranked four in natural gas production in the U.S., groundwater supply is a primary concern; therefore, prior to hydraulic fracturing, operators are required to obtain regulatory approval and conduct a detailed water source analysis of water to be used in hydraulic fracturing. The state also requires disclosure of all chemicals used in hydraulic fracturing operations. Although state regulations do not require operators to conduct groundwater quality monitoring, the State Department of Natural Resources has been actively working with the U.S. Geological Service to develop a statewide network of water wells that are monitored in order to evaluate water levels and water quality. The program specifically focuses on areas of active hydraulic fracturing (the Brown Dense Shale, Haynesville, and Tuscaloosa) and has selected a network of 100 wells in this area to gather data annually and compared to past results to determine if there are any changes in quality or level. Well owners are notified when potential problems are detected and additional investigation will be conducted.

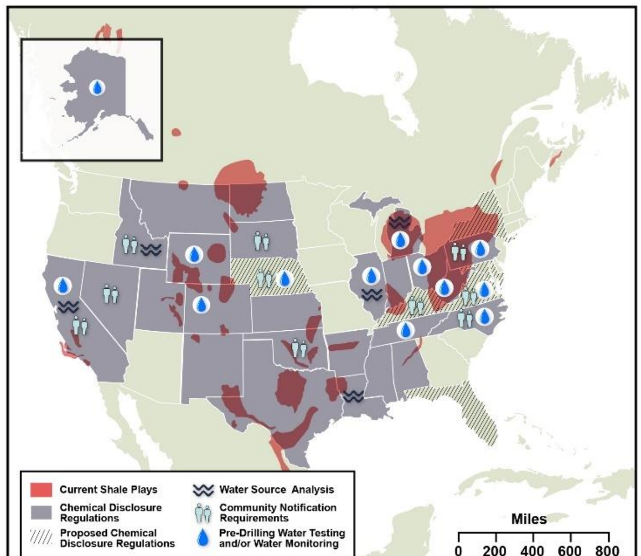

Figure 8 – States with Chemical Disclosure Requirements

Water Quality Monitoring

As mentioned previously, eleven states also have regulations pertaining to baseline and on-going water quality monitoring (Figure 9); including four of the top producing states (California, Colorado, Wyoming, and Pennsylvania). Many of these regulations have been enacted between 2012 and 2016, in response to the rise in hydraulic fracturing. These regulations address pre-drilling testing of groundwater and in some cases surface water to establish baseline conditions of the water sources that could potentially be impacted by hydraulic fracturing operations. These baseline studies typically include water quality indicators such as alkalinity, pH, specific conductance, TDS, chloride, sulfate, cations, anions, and common metals. In addition, many operators may perform their own studies to better define the baseline water quality conditions prior to drilling.

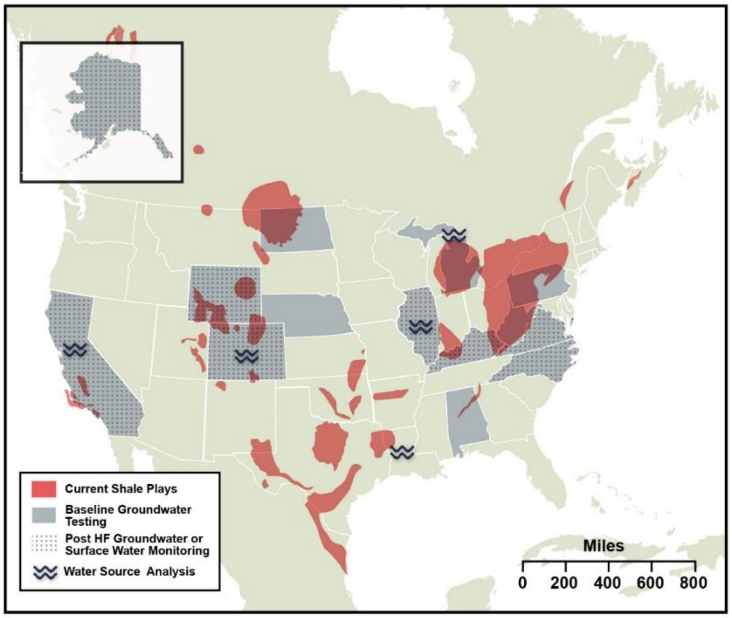

Figure 9 - States with Water Quality Monitoring and Source Assessment Requirements

Water quality monitoring requirements are leading to database development that can allow EPA to prove out its finding. With the majority of testing and monitoring requirements enacted since 2012, there has been a marked increase in the amount of natural gas production covered by states that having water quality testing/monitoring requirements. The graph below shows the top 10 states that have experienced the most hydraulic fracturing (EPA 2015) and the rise in gas production covered by water quality testing/monitoring (EIA 2016; Figure 10). As observed, monitoring in these states has risen from 13 percent in 2010 to 37 percent in 2015; a strong indicator of an emerging and comprehensive data source for EPA to prove out its finding that there is no significant correlation between hydraulic fracturing and drinking water resources impairment.

California, Colorado, Illinois are the only states that have specific provisions requiring on-going groundwater and/or surface water monitoring associated with hydraulic fracturing. In California, under Senate Bill 4, groundwater monitoring is required before and after any well stimulation activities, along with a plan for wastewater disposal. In accordance with this bill, the State Water Resources Control Board adopted in 2015 specific groundwater monitoring criteria for hydraulic fracturing operations (SWRCB 2015). Colorado requires baseline and post-completion surface water sampling if stimulation activities occur within a Surface Water Supply Area. It also has specified setbacks and precautions for hydraulic fracturing near surface waters and tributaries that are sources of public drinking

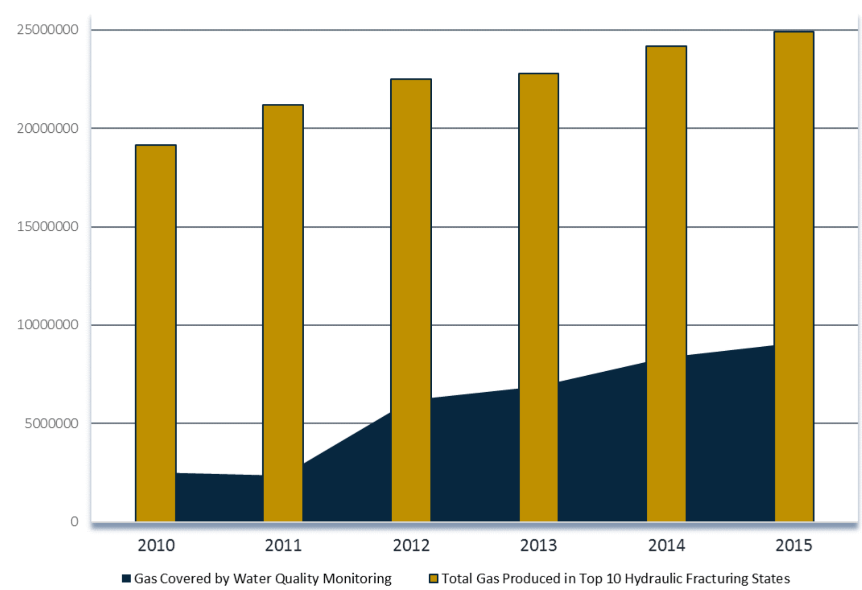

Figure 10 – Gas Produced in Top 10 Hydraulic Fracturing States and the Rising Amount of Gas Produced in States with Water Quality Monitoring and Source Assessment Requirements

water (COGCC 2015). Similarly, Illinois signed into law the Hydraulic Fracturing Regulatory Act (July 2013), which requires both baseline and periodic post-hydraulic fracturing testing of surface water and groundwater sources near wells that are hydraulically fractured. The act also requires operators conducting hydraulic fracturing activities to demonstrate that any observed contamination of water sources near a well site is not caused by hydraulic fracturing. In addition, the act includes setbacks of wells that are hydraulically fractured from public water supply intakes.

Michigan proposed revisions to its existing oil and gas regulations in October 2013, specifically addressing hydraulic fracturing, which became effective on March 11, 2015. The adopted changes focus on four keys areas: water withdrawal assessment and monitoring; water quality sampling; monitoring and reporting; and chemical additive disclosure. Specifically, permit applicants are required to use Michigan's water withdrawal assessment tool to determine if the water use would adversely impact rivers or streams, and if there is a water supply well within 1,320 feet of a proposed withdrawal, the operator is required to install a monitoring well. Oil and gas operators are also required to collect baseline samples from up to 10 water supply wells within 1,320 feet of the oil and gas wells, six months or less before drilling operations begin (Michigan DEQ 2014).

Three states (Ohio, Tennessee and West Virginia) have regulations that require water testing prior to hydraulic fracturing, though on-going monitoring in dedicated groundwater monitoring wells is not required. Ohio requires operators to collect pre-drilling water samples within 1,500 feet of proposed horizontal wells for both urban and rural wells and disclose the results in permit applications. The regulations also require well operators to disclose the proposed source of water used in the well drilling and hydraulic fracturing process. In addition, Pennsylvania requires operators to characterize the baseline water quality within 1,000 feet of a well proposed for hydraulic fracturing.

Tennessee Rule 0400-52-02-01, revised in 2011, requires an applicant for a drilling permit to collect and analyze a sample from any drinking water wells within ½ mile radius of the well proposed to be fractured, if the hydraulic fracturing operation will use greater than 200,000 gallons of liquids and if the landowner requests the testing.

In West Virginia, in accordance with West Virginia Code Section 22-6A-10, at the request of an owner or water purveyor, operators must sample and analyze water wells within 1,500 feet from the well pad prior to hydraulic fracturing. If no such request is made, operators must sample and analyze water from at least one well within 1,500 feet of the well pad.

In Wyoming, state legislators passed a law in late 2013 requiring baseline groundwater monitoring for all oil and gas wells (not just wells that would be completed via hydraulic fracturing). The Wyoming Oil and Gas Conservation Commission drafted rules which went into effect March 1, 2014. Under the new rule, all operators are required to submit a baseline groundwater sampling, analysis, and monitoring plan with applications for permits to drill or deepen a well. A variance to the rule may be provided if no water sources exist within ½ mile from the proposed well, if available water sources are determined to be improperly maintained or non-operational, or if the owner of a water source does not consent to providing the operator access. Initial sampling of wells must occur within 12 months prior to spudding the first well on a well pad. Subsequent sampling is required at intervals between 12 and 24 months and between 36 and 48 months following setting the production casing (WOGCC 2014).

Additional State Regulations

Table 5, below, summarizes the broader regulatory landscape for hydraulic fracturing across the US. All states with oil and natural gas production have regulated hydraulic fracturing, for several decades through their existing oil and gas regulatory framework. As unconventional development has rapidly grown, states have developed new provisions to add to their oil and gas regulatory framework which directly address hydraulic fracturing practices and technology. As described previously, these regulatory frameworks differ between states, based on the physical and technical characteristics of reservoirs and environmental conditions at each unconventional play, how individual state governments seek to balance environmental risks, public perception, and economic concerns.

Table 5 - Summary of State Hydraulic Fracturing Regulations (2014)

States with actual or potential shale development	Annual Production Volumes		Site Development and Preparation				Well Drilling and Production					Flowback/Wastewater Storage and Disposal					Other	
	Natural Gas Production (million cubic feet)	Oil Production (thousand barrels)	Pre-Drilling Water Well Testing Required?	Water Withdrawal Restriction	Setback Restrictions from Buildings	Setback Restrictions from Water Sources	Cement Type Regs	Casing and Cementing Depth Regulations	Casing Cement Circulation Regs	Venting and Flaring Regs	Chemical Disclosure Required	Fluid Storage Regs	Freeboard Regs	Pit Liner Regs	Flowback/ Wastewater Transportation Tracking	Underground Fluid Injection	Accident Reporting Requirements	# of regulating Agencies
Texas**	7,953,343	1,262,011	N	Permit Required	Y	N	Y	Performance Standard	Y	Addressed in Permit	Y	Y	N	Addressed in Permit	permit/ approval	Some local bans/ moratoria	Y	2
Pennsylvania**	4,214,643	7,369	N	Permit Required	Y	Y	Y	Y	Y	Discretionary Standard	Y	Y	Y	Y	Record Keeping	Allowed	Y	2
Oklahoma**	2,310,114	157,770	N	Permit Required	N	N	N	Y	Y	Restricted	Y	Y	Y	Y	permit/ approval	Allowed	Y	2
Louisiana	1,980,287	63,311	N	Registration and Reporting	Y	N	N	Y	Y	Venting - Banned Flaring - Restricted	Y	Y	Y	Y	permit	Allowed	Y	2
Wyoming	1,791,235	87,537	Y	Permit Required	Y	Y	Y	Y	Y	Restricted	Y	Y	N	Discretionary	N	Allowed	Y	3+
Colorado	1,631,390	119,239	Y	Permit Required	Y	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Allowed	Y	2
New Mexico	1,180,808	149,403	N	Permit Required	Other Setback Requirements	Other Setback Requirements	N	Addressed in Permit	Y	Restricted	Y	Y	Y	Y	permit/ approval	Allowed	Y	2
Arkansas	1,123,678	6,536	N	Permit Required	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	Some local bans	Y	3+
West Virginia**	1,040,250	8,282	Y	Permit Required	Y	Y	Y	Y	Y	Discretionary Standard	Y	Y	Y	Y	Record Keeping	Allowed	Y	1
Ohio**	518,767	26,330	Y	Permit Required	Y	Y	Y	Y	Y	Venting - Banned Flaring - allowed	Y	Y	N	N	permit/ approval	Some local bans/ moratoria	N	3+
Utah	453,207	36,970	N	Permit Required	N	N	Permit	Y	Y	Venting - Banned Flaring - Discretionary Standards	Y	Y	Y	Y	N	Allowed	Y	2
Alaska	345,331	176,240	Y	Permit Required	Y	N	Y	Y	Y	Restricted	Y	Y	Y	Y	N	Allowed	Y	2

States with actual or potential shale development	Annual Production Volumes		Site Development and Preparation				Well Drilling and Production					Flowback/Wastewater Storage and Disposal					Other	
	Natural Gas Production (million cubic feet)	Oil Production (thousand barrels)	Pre-Drilling Water Well Testing Required?	Water Withdrawal Restriction	Setback Restrictions from Buildings	Setback Restrictions from Water Sources	Cement Type Regs	Casing and Cementing Depth Regulations	Casing Cement Circulation Regs	Venting and Flaring Regs	Chemical Disclosure Required	Fluid Storage Regs	Freeboard Regs	Pit Liner Regs	Flowback/ Wastewater Transportation Tracking	Underground Fluid Injection	Accident Reporting Requirements	# of regulating Agencies
North Dakota	326,437	428,550	N	Permit Required	Y	Performance Standard	N	Y	Y	Venting - Banned Flaring - allowed	Y	Y	N	Y	Permit	Allowed	Y	1
Kansas	286,080	44,618	N	Permit Required	N	Y	Y	Y	Y	Restricted	N	Addressed in Permit	Y	Y	Y	Allowed	Y	2
California	252,718	201,738	Y	Permit Required	Other Setback Requirements	Other Setback Requirements	Y	Y	Y	N	Y	Y	N	N	N	Allowed	N	3+
Alabama	181,054	9,734	N	Registration and Reporting	Y	Y	Y	Y	Y	Restricted	N	Y	Y	Y	Y	Allowed	Y	2
Virginia	15	131,885	Y	Permit Required	Y	N	N	N	N	Restricted	N	Y	Y	Y	N	Allowed	Y	3+
Michigan	6,449	114,946	Y	Permit Required	Y	Y	Y	Y	Y	Restricted	Y	Y	N	Y	permit/approval	Allowed	Y	1
Kentucky	2,862	78,737	N	N	Y	N	N	Y	Y	Discretionary Standard	N	Y	Y	Y	permit	Allowed	Y	3+
Montana	28,641	59,930	N	Permit Required	N	N	Addressed in Permit	Performance Standard	Y	Restricted	Y	Y	Y	Addressed in Permit	N	Allowed	Y	2
Mississippi	24,929	54,440	N	Permit Required	N	N	N	Y	Y	Restricted	Y	Y	Y	Y	N	Allowed	Y	2
New York* (note: HVHF prohibited as of July 2015)	341	20,201	N	Permit Required	Y	Y	Y	Y	Y	Restricted	Y	Y	Y	Y	permit/ approval	Allowed	Y	1
South Dakota	1,631	15,307	N	Permit Required	N	N	Permit	Y	Y	Venting - Banned Flaring - allowed	N	Y	N	Y	N	Allowed	Y	1
Indiana	2,219	6,616	N	Permit Required	Y	N	Y	Addressed in Permit	Y	N	N	Y	Y	Permit	N	Allowed	Y	2
Tennessee	342	5,294	Y	registration and reporting	Y	Y	N	Y	Y	Venting - Discretionary Flaring - Restricted	N	Y	N	Y	N	Allowed	N	2
Illinois	9,521	2,626	Y	Permit Required	Y	N	N	Y	Y	Venting - N Flaring - restricted	Y	Y	N	Y	Y	Allowed	Y	2

States with actual or potential shale development	Annual Production Volumes		Site Development and Preparation				Well Drilling and Production					Flowback/Wastewater Storage and Disposal					Other	
	Natural Gas Production (million cubic feet)	Oil Production (thousand barrels)	Pre-Drilling Water Well Testing Required?	Water Withdrawal Restriction	Setback Restrictions from Buildings	Setback Restrictions from Water Sources	Cement Type Regs	Casing and Cementing Depth Regulations	Casing Cement Circulation Regs	Venting and Flaring Regs	Chemical Disclosure Required	Fluid Storage Regs	Freeboard Regs	Pit Liner Regs	Flowback/ Wastewater Transportation Tracking	Underground Fluid Injection	Accident Reporting Requirements	# of regulating Agencies
Nebraska	402	2956	Y	Permit Required	N	N	Addressed in Permit	Performance Standard	Y	Venting - Banned Flaring - allowed	N	Addressed in Permit	Y	Y	Y	Allowed	Y	2
Maryland	20	0	N	Permit Required	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	No reg	Allowed	Y	1
Georgia*	0	0	N	Permit Required	Y	N	Addressed in Permit	Performance Standard	Y	N	N	Y	Addressed in Permit	Addressed in Permit	N	Allowed	Y	1
New Jersey*	0	0	N	Permit Required	N	N	N	Performance Standard	N	N	N	N	N	N	N	Allowed	Y	0
North Carolina*	0	0	N	Registration and Reporting	N	N	N	Y	Y	N	N	Y	N	N	N	Statewide Ban	Y	1
Vermont*	0	0	N	Permit Required	N	N	N	N	N	N	N	N	N	N	N	Allowed	N	1

Sources: Resources for the Future 2013. The State of State Shale Regulations; U.S. Energy Information Administration 2016;

* Very little shale gas development—no natural gas wells as of 2010.

**Top 5 states by number of natural gas wells

STRONGER Reviews

In addition to the state regulations, the State Review of Oil and Natural Gas Environmental Regulations (STRONGER), a non-profit, multi-stakeholder organization helps oil and natural gas producing states evaluate their environmental regulations associated with the exploration, development and production of crude oil and natural gas. Prior to 1999, regulatory reviews were jointly conducted by the IOGCC and EPA. The EPA, US Department of Energy and the America Petroleum Institute, among others, have provided funding to support the STRONGER reviews of the state regulatory review processes, which has been ongoing since 1999. STRONGER has conducted reviews of 22 state regulatory programs for oil and gas production, including: Alaska (July 2015), California (December 2002), Wyoming (May 1994), Colorado (October 2011), North Dakota (July 1997), Oklahoma (January 2011), Texas (August 2003), Louisiana (March 2011), New Mexico (August 2001), Kansas (August 1993), Arkansas (February 2012), Illinois (August 1996), Indiana (April 2005), Michigan (July 2003), Ohio (January 2011), Kentucky (August 2006), Tennessee (September 2007), West Virginia (January 2003), Pennsylvania (September 2013), New York (September 1994), Virginia (April 2004), and North Carolina (February 2012).

In 2009, a Hydraulic Fracturing Workgroup was formed within STRONGER to address regulatory issues specific to hydraulic fracturing. STRONGER reviews beginning 2010 tended to focus on oil and gas regulations as they apply to hydraulic fracturing operations. STRONGER developed guidelines for assessing hydraulic fracturing regulations in 2010 and the STRONGER reviews of this completion technique generally follow these guidelines for each state review. Table 6 summarizes the results of the eight STRONGER reviews that have been conducted since 2011, when the hydraulic fracturing review guidelines were first implemented.

Table 6 - Summary of State STRONGER Reviews

Existing Strengths of State Regulatory Program	Recommendations from STRONGER Review
Alaska[1]	
The Alaska Oil & Gas Conservation Commission (AOGCC) enacted a regulatory update prior to large-scale hydraulic fracturing operations occurred in the State.	Conduct a STRONGER review in the future that includes the other Alaskan agencies that have significant responsibilities and oversight of hydraulic fracturing.
AOGCC practices transparent policies in the disclosure of records. Public records requests are typically processed in 10 days or less.	
Arkansas[2]	
Since 2006, AOGC reviewed and revised numerous rules concerning environmental and production related concerns associated with hydraulic fracturing.	Notification prior to hydraulic fracturing so field inspectors can better monitor operations and related activities.
Developed water well complaint protocol, guiding staff towards efficient review and response to water well complaints and identification of laboratory analysis parameters.	Funding to continue support of Arkansas Department of Environmental Quality and seek resources to better Department.

AOGC's user friendly web site informs public of hydraulic fracturing operations and other pertinent information regarding hydraulic fracturing.	Funding to increase AOGC Staffing Levels to ensure Commission inspection goals are met.
Colorado[3]	
Operators are required to keep chemical inventories at all well sites, which must be provided to agencies and health care providers upon request.	To help protect water resources from contamination, standards should be developed for minimum and maximum surface casing depths. All past problems related to surface casing in a hydraulically fractured well should be considered when developing this standard.
Bradenhead annulus pressure during hydraulic fracturing operations must be measured and reported in an effort to help protect groundwater.	Materials used, aggregate volumes of fracturing fluids, proppants used and fracture pressures should be recorded.
Identification of potential pathways for fluid migration is required in certain circumstances.	An evaluation of naturally occurring radioactive material in hydraulic fracturing wastes should be required.
	The availability of water resources for fracturing operations should be evaluated, as water supply is a significant issue in this arid region. Plans should be implemented to maximize water reuse and recycling if it is determined that water supply is an issue.
	Requires operators to study and address potential pathways for fluid migration in more detail.
	Stricter regulations related to providing notification and receiving approval prior to hydraulic fracturing.
Louisiana[4]	
The use of alternative water sources and the recycling of waste fluids are encouraged and promoted by recent legal amendments.	The minimum depth of surface casing is based on the total depth of the well. To protect groundwater, the depth to the USDW and depths of productive zones should also be considered.
Permitting of commercial waste fluid treatment and reclamation for hydraulic fracturing water supply purposes has been streamlined to make the process easier.	There are no cementing requirements for well construction or for casing weights or grades. Standards should be developed to meet anticipated pressures.
Increase in water source and volume reporting requirements, coupled with recycling provisions has significantly decreased water demand.	Reporting should include materials used; volumes of fracturing fluids, proppants used and fracture pressures.
Surface water has been sufficiently analyzed and there is adequate water available for anticipated HF needs.	Spill Prevention and Control Plans are currently required, but additional contingency plans are recommended.
North Carolina[5]	

North Carolina has a mature environmental regulatory system, staffed with experienced professionals that possess excellent institutional knowledge.	Need to develop formal standards for permitting oil and gas wells, as opposed to a case-by-case basis.
The structure of regulatory agencies allows for good program coordination. The majority of the agencies fall under the Assistant Secretary for the Environmental in the Dept. of Environmental and Natural Resources.	Use stakeholder groups such as independent scientific advisory groups, local advisory committees, groups of government, public and industry representatives, or other similar mechanisms, in program development.
There are no abandoned or orphan wells in North Carolina. There are no active production wells in the State.	Develop oil and gas technical criteria to address oil and gas activities, including administrative criteria, technical criteria related to exploration and production waste management, stormwater management, abandoned sites, and naturally occurring radioactive materials, and hydraulic fracturing.
Ohio[6]	
Comprehensive well completion reporting is required and must include type and volume of fluid used for stimulation, reservoir breakdown pressure, recovered fluid containment methods, etc.	Chemical disclosure regulations should be more comprehensive that currently exist.
Casing and cementing plans are required during the permitting process.	The state should evaluate the impact of hydraulic fracturing on surface and groundwater availability.
Notification is required before hydraulic fracturing occurs.	Stricter spill notification regulations.
Well permits require a comprehensive review of potential pathways for groundwater contamination.	
Impoundment placement and construction guidelines are implemented through permit conditions.	
Strong enforcement tools.	
Oklahoma[7]	
Prohibits pollution of a fresh water from well completion activities.	Reporting requirements should include volumes of hydraulic fracturing fluids and proppants used, pressures recorded, and hydraulic fracture materials used.
Provides minimum casing and cementing standards.	Recycling of flowback water and use of alternate, lower quality water should be encouraged.
	More stringent regulations with regard to notification to the Oklahoma Corporation Commission prior to fracturing operations should be required.

Provides strong regulations related to the construction and maintenance of flowback water storage tanks. Requires sampling of hydraulic fracturing waste materials or flowback water to monitor chemicals of concern, primarily salts and TDS.	The State should procure additional funding to ensure a staffing needs are met based on expected needs in the future.
Pennsylvania[8]	
Comprehensive water planning process to ensure that demands on water resources related to hydraulic fracturing are managed through a planning process.	Stronger casing and cementing requirements have been proposed but have not been adopted into law.
Regulations encourage baseline groundwater quality sampling plans.	Encourage more comprehensive baseline studies in situations where there are increased risk factors.
Potential risks must be identified in a preparedness plan, which requires operators to list chemical additives used and wastes generated.	Require operators to identify potential conduits for fluid migration.
Waste characterization is required, including generation, transportation and disposal tracking.	Require notification prior to hydraulic fracturing. Currently this information is only transmitted via well completion reports and DEP does not have the opportunity to inspect.
Strong waste storage tank/impoundment requirements.	Secondary containment requirements for tanks used in hydraulic fracturing regulations.

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SECTION 5

Key Findings

This review provides three lines of evidence to support EPA's conclusion that no studies or data have indicated a widespread, systematic effect on drinking water resources as result of hydraulic fracturing, and that there is sufficient monitoring in place, overseen and enforced by state authorities, to continue gathering data to prove out the finding.

CASE STUDIES AND RESEARCH QUANTITATIVELY SUPPORT EPA'S FINDING

EPA drew its conclusion that hydraulic fracturing does not cause widespread, systemic effects based on the state-of-the-science and employed a structured and logical method for assessing potential effects by focusing on those areas where ample hydraulic fracturing has occurred near drinking water supplies and residents. If there was a significant correlation between impaired drinking water resources and hydraulic fracturing, that connection would be manifested in the areas that EPA evaluated. This finding is corroborated by a large, credible body of case studies and scientific literature.

Through the comprehensive review of industry and agency studies, this report provides additional quantitative information that further supports EPA's finding of no widespread, systemic effects to water resources from hydraulic fracturing. The data demonstrate the absence of a direct correlation between hydraulic fracturing and impairments to drinking water quality.

RECENT, SIMILAR COMPREHENSIVE STUDIES COME TO SIMILAR CONCLUSIONS AS EPA

State and federal reviews were produced in 2014 and 2015 that had a similar mandate to EPA's: to evaluate the potential effects of hydraulic fracturing to drinking water resources, and other environmental resources. The most comprehensive is that of the California CCST, which studied the effects of well stimulation (focusing on hydraulic fracturing) in California for the US BLM (CCST 2014) and the state of California Department of Conservation (CCST 2015). The CCST concluded that the direct effects of hydraulic fracturing appear small, and that good management and mitigation measures can address the vast majority of potential direct impacts of well stimulation. Although no adverse effects have been demonstrated, the study recommended that, as a precautionary measure, the state should disallow the use of any chemical with unknown environmental effects and work with industry to "limit the use of hazardous and poorly understood chemicals" per Recommendation 3.2 of the CCST report (2015).

Like the EPA study, the CCST study found no documented instances of hydraulic fracturing or acid stimulations directly causing groundwater contamination in California. However, because fracturing in California tends to be in shallow wells and in a few locations, hydraulic fractures could possibly intersect protected groundwater, mostly in the San Joaquin Valley. The CCST report recommended that the State should investigate these sites to see if contamination has occurred and develop a regulatory approach to managing them. LLNL and the State Water Resources Control Board followed this recommendation, and developed a robust groundwater monitoring protocol that is now required prior to the issuance of a permit to conduct hydraulic fracturing in the state; while the State and EPA are jointly evaluating the possible occurrence of injection into protected aquifers.

INDUSTRY PRACTICE AND STATE REGULATIONS MINIMIZE RISK AND LIMIT INCIDENTS AND PROVIDE FOR CONTINUED STUDY AND MONITORING

Agencies developed regulations and policies with a strong understanding of the causative mechanisms of how hydraulic fracturing could impair drinking water resources. The common theme in both the federal and state level regulatory frameworks is *prevention* of an incident through the assignment of well design/construction and equipment safeguards that specifically target the causative mechanisms. These preemptive measures are a key contributing factor to the limited number of recorded drinking water resource impairments resulting from hydraulic fracturing.

EPA is justified in its position to let the new information prove out its finding and amend the regulations based on the issues identified through the state-of-the-science. Both federal and state regulatory frameworks, as well as industry operating practices, are still evolving as new information sources come on line. These new data sources provide the basis for an adaptive regulatory approach to refine rules and guidance on top of an already successful strategy focused on incident prevention. For example, many of the states where hydraulic fracturing is occurring have initiated groundwater testing and/or monitoring programs as a condition of permit issuance. These monitoring programs are providing ongoing quantitative support that hydraulic fracturing is not leading to widespread, systemic effects to drinking water resources. Existing data quantitatively supports EPA's principal finding, and ongoing monitoring provides additional assurance and a growing database to further prove out the finding.

SECTION 6

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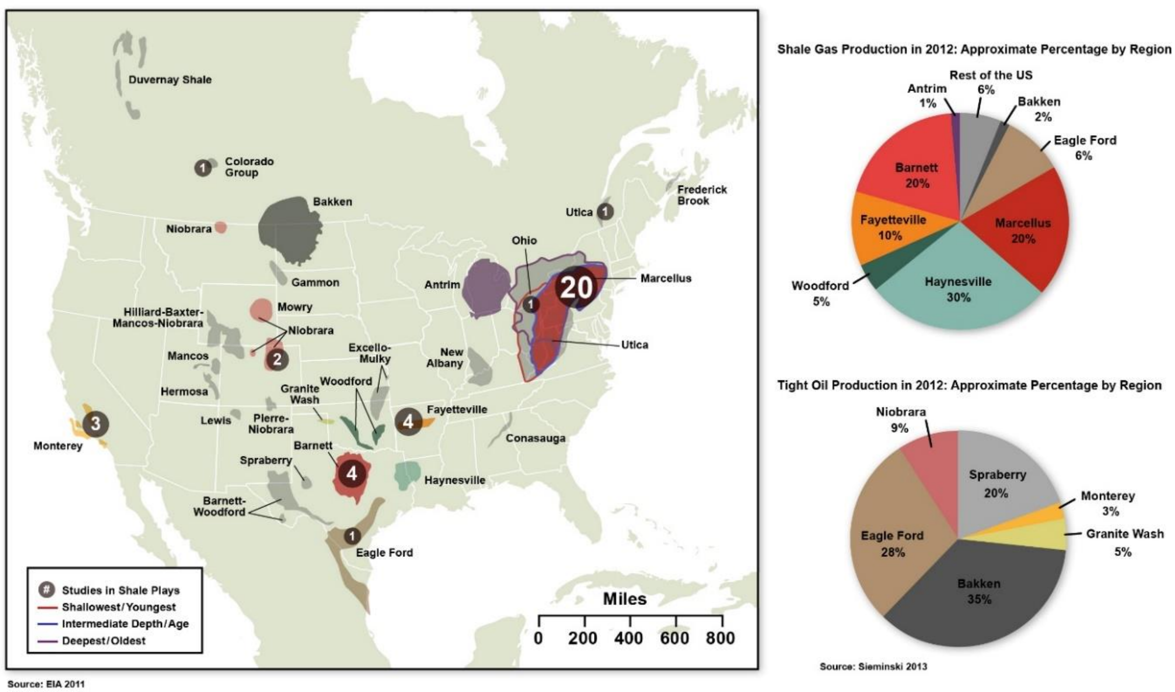
Appendix A. Literature Review

This Appendix provides a brief summary of each study conducted to 2016, discussing the potential impacts of hydraulic fracturing on water resources. We have organized the summaries by different areas of shale gas or oil development (shale plays). The figure below depicts the active shale plays in North America, the volume of shale gas and shale oil estimated to be held in each, and the number of studies conducted in each (dark circles on map). An annotated bibliography or the literature reviewed is provided after these summaries.



Shale Play Areas and Associated Production of Shale Gas and Tight Oil in Comparison to Number of Published Studies

POST-2014 CASE STUDIES AND LITERATURE

Enhanced EPA Oversight and Action Can Further Protect Water Resources from the Potential Impacts of Hydraulic Fracturing (Report No. 15-P-0204; July 2015)

In July 2015, the EPA Inspector General (OIG) released a report on the measures and policies EPA can use to further protect water resources from hydraulic fracturing treatments. The OIG broke down the process of an unconventional play to identify the stages where water resources could be affected by

HVHF, as provided in Table A-1 below. This approach allowed the OIG to perform a comprehensive assessment to find the areas where EPA could improve oversight and management of HVHF treatments. In addition to existing industry practices and regulations, EPA identified two specific areas where enhanced oversight and planning will reduce risks and assist in securing public confidence in the Agency's role in managing the chemical mix used in HVHF.

Table A-1 – Potential Impacts to Water Resources Per Stage of an Unconventional Play

Stage	Potential Impacts to Water Resources
Construction	• Erosion and sediment runoff into surface waters from land disturbing activities impacting water quality, aquatic life and wetlands. • Improper well construction could impact water resources in other stages of the process. • Spills of drilling mud (i.e., a complex mixture of chemicals used to control pressure, lubricate the drill bit, stabilize the shale formation, control fluid loss, and retrieve cuttings).
Water Acquisition	• Impacts depend on the time of the year, the geographic location of water withdrawals and current water-management practices, but there could be impacts on local water quantity and quality.
Chemical Mixing	• Surface spills or spills that reach the subsurface of individual hydraulic fracturing chemicals or fracturing fluid (i.e., chemicals mixed with water for hydraulic fracturing).
Well Stimulation	• Migration of chemicals and natural gas/oil to groundwater sources as a result of improper well construction, well casing or cement failure under high pressure and/or repeated fracturing. • Migration of fluids through the hydraulically fractured network and/or the existing faults and fractures in the subsurface. • Spills and leaks from hydraulic fracturing equipment (e.g., pumps and flowlines).
Wastewater Management & Storage	• Surface spills and releases of flowback and produced waters while transporting wastewater to or from storage tanks or impoundments containing constituents from the formation water (e.g., naturally occurring radioactive material, barium, dissolved solids, heavy metals and salts).
Wastewater Treatment and/or Disposal	• Water treatment facilities (i.e., publicly owned treatment works and centralized waste treatment) may not be able to effectively treat wastewater from hydraulic fracturing activities, which can impact surface water when discharged. • Spills to surface waters during transportation of wastewater to treatment facilities or disposal sites.

Source: OIG 2015

The first area identified by the OIG is improving oversight of permitting HVHF treatments that use diesel fuel in the chemical mix, specifically the issuance of Class II permits for underground injection. EPA found that some states with primacy on issuing permits per the Safe Drinking Water Act (SDWA) were not issuing Class II injection permits for some projects that relied on diesel fuel in the chemical mix. In 2011, a congressional investigation reported that the injection of over 32 million gallons of diesel fuels without permits occurred in 19 states between 2005 and 2011 (OIG 2015). This congressional finding prompted EPA to review and clarify the definition of diesel fuels to specifically include kerosene through agency memorandum and permitting guidance in February 2014. The OIG's recommendation of improved oversight of UIC Class II permits demonstrates the regulatory fine tuning that EPA is considering in protecting groundwater resources.

The second area of improvement cited by the OIG is to develop a plan for responding to the public's concerns regarding the chemical mix used in HVHF. The OIG encourages the EPA to develop a "next steps" plan and/or address the 260,000 public comments received in response to the release of an Advanced Notice for Proposed Rulemaking regarding disclosure of the chemicals used in the hydraulic fracturing mix. This is an issue of communication between EPA and the public, and further demonstrates the absence of any widespread or systemic effects to water resources.

Government Accountability Office Review of EPA's Class II Program (GAO-14-555; June 2014)

The Government Accountability Office (GAO) performed a review of EPA's management of the Class II program due to the proliferation of hydraulic fracturing and the underground injection of approximately 2 billion gallons of fluid per day. As part of this review, GAO found that the state-managed and EPA-managed Class II programs had effective safeguards in place to protect underground drinking water resources. Subsequently, officials interviewed by GAO reported few known instances of contamination from the injection of fluids into Class II wells in the last 5 years (GAO 2014). Table A-2 below provides a breakdown of alleged contamination from Class II wells across eight states from 2008 to 2012. These instances are based on well inspections and violations that may have been significant enough to contaminate an underground drinking water resources. Officials from the eight states also based their statements about few or no instances of contamination from Class II wells on their efforts to track and investigate complaints from the public on possibly contaminated drinking water. The GAO's findings directly support EPA's conclusion that HVHF does not cause widespread or systemic impairment of drinking water resources. EPA and state UIC programs have the appropriate safeguards in place to minimize the potential contamination of drinking water resources as result of HVHF.

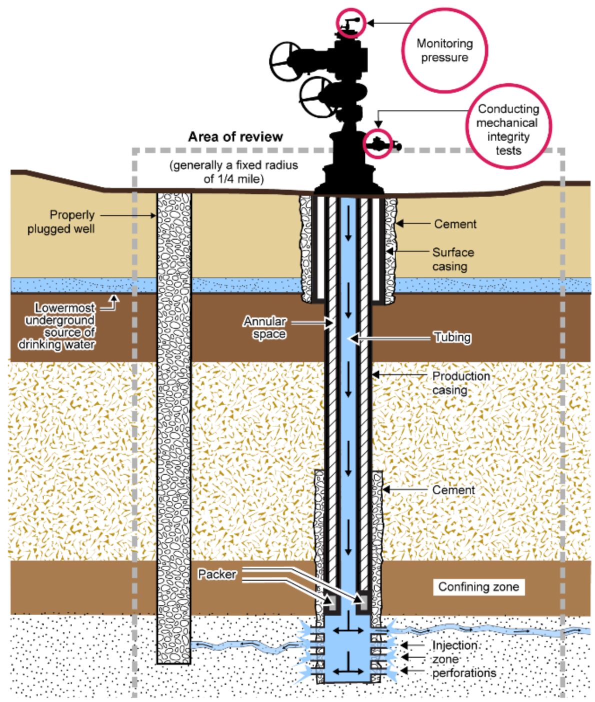


Table A-2 – Instances of Alleged Drinking Water Contamination in Selected States from Class II Wells

State	2008	2009	2010	2011	2012
California	0	9*	12*	0	3
Colorado	0	0	0	0	0
Kentucky	0	0	0	0	0

North Dakota	0	0	0	0	0
Ohio	0	0	0	0	0
Oklahoma	1	2	4	1	2
Pennsylvania	0	0	0	0	0
Texas	0	1	0	0	0

** GAO noted in its review that all the 2009 violations and 9 of 12 of the 2010 violations in California were the result of an individual operator that was injecting fluids illegally into multiple wells.

Source: GAO 2014

MARCELLUS SHALE

Dimock, Pennsylvania (Multiple Sources)

The following provides a brief summary of the Pennsylvania Department of Environmental Protection (PADEP) and EPA investigations into alleged hydraulic fracturing-related groundwater quality impacts contamination in Dimock, Pennsylvania. Information in this summary was gathered from publicly available official notices submitted between the PADEP Department of Environmental Protection and Cabot Oil and Gas Corporation (Cabot), the oil and gas operator in question, as well as action memorandum, and news releases from the EPA.

Cabot began drilling operations for natural gas in the Dimock area in 2008. In 2009, residents complained of cloudy, foul-smelling water. The PADEP conducted an investigation and determined that several of the drinking water wells in the area contained elevated levels of methane. The investigation also noted several improper or insufficient well construction issues for the gas wells drilled by Cabot casing and identified excessive borehole pressure in a select number of those gas wells owned and operated by Cabot. The PADEP Department of Environmental Protection asserted that Cabot was responsible for the elevated methane levels in 18 private drinking water wells. Following the initial investigation by the PADEP, in November 2009 order, the Pennsylvania Department of Environmental Protection ordered Cabot to remediate the gas all of the wells by March 31, 2010. Separately, also in November 2009, fifteen families from Dimock filed a federal lawsuit against Cabot for allegedly contaminating their drinking water.

Although Cabot was able to remediate a subset of the wells stipulated in the order, it apparently did not meet the March deadline to remediate all of the wells. Consequently, the PADEP issued another Action Memorandum in April 2010, requiring Cabot to pay a $240,000 penalty fine as well as a $30,000 per month assessment until Cabot met all of its obligations under the first order issued in November 2009. In addition, the PADEP ordered Cabot to plug three gas wells within 40 days of the new order (April 2010) that were alleged to be the source of methane affecting the potable wells groundwater of 14 homes. Cabot was also required to install a methane treatment system at 19 affected homes within 30 days and provide immediate temporary water supply source until each of the systems was installed.

Further, the PADEP suspended all pending well permit applications for Cabot and stated that Cabot could not drill any new wells for a 1-year period. In October 2011, the PADEP announced that Cabot had fully complied with the consent orders.

Concurrent with the investigative work being conducted by the PADEP, the EPA was also conducting its own evaluation of the issues in Dimock. In December 2011, EPA stated that the Dimock water was safe to drink. In response to this statement, local residents submitted analytical results of their own water testing to the EPA, maintaining that their water was still impacted. (Snyder 2012). In response to these allegations, in early January 2012, the EPA initiated another investigation in January 2012 to assess into drinking water quality in the area. The EPA sampled waters from 64 homes in Dimock, including the same homes previously sampled by the PADEP and an additional set of homes identified by EPA as potentially affected. The results of that investigation confirmed the original EPA position and concluded that the composition of the water did not require further EPA action.

The EPA publicly released the analytical results for all the samples in May 2012. EPA noted that elevated levels of arsenic, barium, and manganese were detected in some wells, but noted that these constituents are naturally occurring in the area. Further, the agency stated EPA noted that the levels detected were considered safe and did not pose a threat to human health. Water treatment systems remove these constituents and these systems are commonly used in the area. The EPA also resampled four wells where previous data showed contamination. At one of those wells, EPA found elevated levels of manganese (a naturally-occurring substance) in untreated well water, but the two homes serviced by that well had water treatment systems the reduced the level of manganese below levels of concern. None of the other wells contained levels of contaminants that would require action. Although one well contained detections of methane, the agency EPA did not conduct further study because methane is documented to be a naturally occurring gas in the surrounding area. EPA has stated that it has no further plans to conduct additional sampling (EPA 2012b). In August 2012, shortly after the EPA ended its investigation, all but one of the families settled their lawsuits with Cabot.

Methane in Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing (Osborn, et al. 2011)

Three studies have been conducted by researchers at Duke University evaluating potential groundwater impacts contamination in the town of Dimock associated with oil and gas operations. The first of these studies was conducted in response to the widespread public concern in Pennsylvania about drinking water contamination from drilling and hydraulic fracturing, and lack of scientific evidence as to whether these activities posed an actual risk. The paper was described by the authors as "the first scientific review of water contamination near hydraulic fracturing operations". The study, which collected and analyzed samples from 68 drinking water wells in the Marcellus and Utica formations in Pennsylvania and New York, evaluated the potential

> Three studies have been conducted at Duke University that evaluated potential groundwater contamination in Dimock, Pennsylvania:
>
> - The 1st study described itself as the "1st scientific review of water contamination near hydraulic fracturing operations"
> - The 2nd study focused on evaluating hydraulic conductivity between shale gas formations and drinking water aquifers
> - The 3rd study focused on identifying sources of stray gas in drinking water wells.

impacts of natural gas drilling and hydraulic fracturing on shallow groundwater quality (focusing specifically on methane impacts), by comparing areas with active drilling and fracturing to areas that were not actively being drilled.

The study noted that methane was detected in 85 percent of the drinking water wells across the region, regardless of gas industry operations, thus demonstrating a regional background in this area of shallow natural gas accumulations in groundwater. However, the study suggested a correlation between methane concentrations contamination in private wells drinking in proximity to hydraulic fracturing and shale gas development (Osborn, et al. 2011). The reported concentration of methane in water collected from the drinking private water wells within 1 kilometer (3,280 feet) of active natural gas drilling and extraction were approximately 17 times higher on average than those further away (Figure A-1). Although methane is known to occur naturally in shallow groundwater aquifers in both of these regions, the testing determined through analysis of the carbon and hydrogen isotopes that the gas found in the wells was consistent with methane gas that originated at depths associated with the targeted reservoirs by oil and gas operators that were drilled (i.e. thermogenic methane).

However, although the testing showed elevated methane levels in the wells, isotopic analyses conducted on the same wells (for the stable isotope signatures of water as well as isotopes of dissolved constituents such as barium and radium), as well as measurements of dissolved salts, did not find any indication that hydraulic fracturing fluids or saline produced water had impacted polluted the groundwater aquifers (Osborn, et al. 2011).

Critiques of the study cite the lack of baseline data. While the study finds higher methane concentrations near active wells and concludes that these increases are the result of hydraulic fracturing operations, it does not compare its data to wells sampled prior to the occurrence of hydraulic fracturing. Others note that the data set is not large enough to draw any definitive conclusions, and that the results are likely to vary regionally. Furthermore, critiques point to areas without drilling where methane was detected in wells, suggesting that claims opining that hydraulic fracturing caused methane impacts in shallow groundwater zones contamination are not scientifically supportable (Bauers 2011).

Natural Migration of Brines Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvania (Warner, et al. 2012)

A second study was conducted by researchers at Duke University in response to questions related to reports of potential drinking water impacts contamination associated with related to hydraulic fracturing in Pennsylvania. This study examined hydraulic conductivity between shale gas formations and the shallower drinking water aquifers in Pennsylvania.

The study analyzed the chemical content of 426 groundwater samples collected from six counties in Northeastern Pennsylvania that did not have links to drilling activities. The

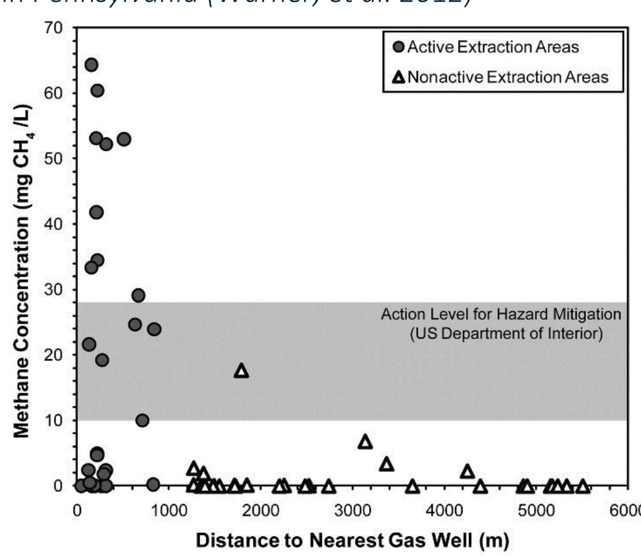


Figure A-1 - Methane Concentrations as a Function of Distance to the Nearest Gas Well from Active and Non-Active Drilling Areas (Osborn, et al. 2011) study then compared the chemical composition of the salts present in the samples to the salts found in brine water from the Marcellus Shale using ternary diagrams as shown in Figure 3 below. For some samples, the researchers found that the salts in the groundwater had the same chemical composition as the salts in the Marcellus Shale brine, suggesting that there are naturally occurring hydrogeological pathways in the Marcellus shale that could allow migration from the shale to shallower aquifers. The authors reported that there is no link between the salinity of the samples and proximity to Marcellus Shale gas wells, stating that “it is unlikely that hydraulic fracturing for shale gas caused this salinization and that it is instead a naturally occurring phenomenon that occurs over longer timescales.” However, the study speculates that “these areas could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations” (Warner, et al. 2012).

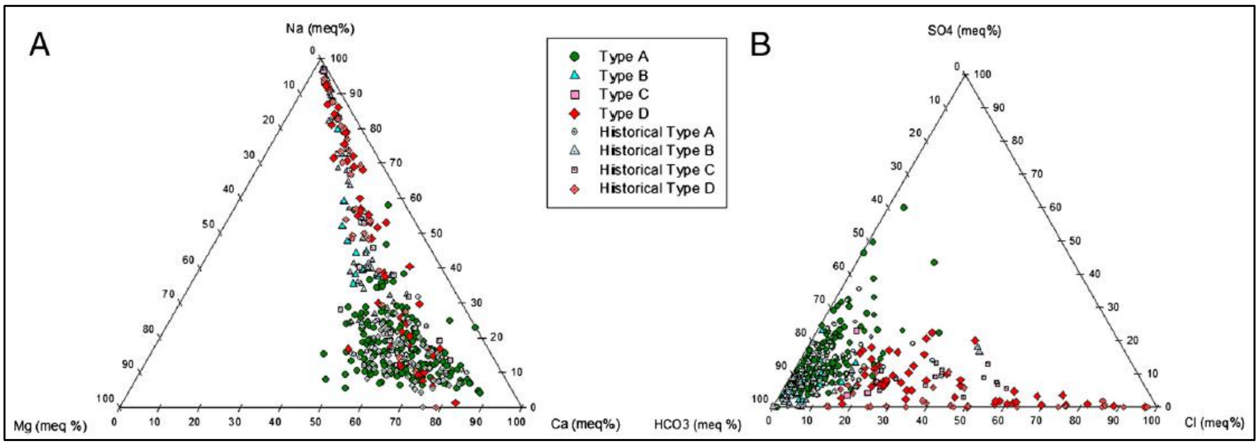


Figure A-2. Ternary Diagrams Displaying the Relative Percent of Cations (A) and Anions (B) in Shallow Groundwater Samples. The Area of Overlap Indicates that Na-Ca-Cl Type Saline Water Was Present Prior to Shale Gas Production (Warner, et al. 2012)

Increased Stray Gas Abundance in a Subset of Drinking Water Wells near Marcellus Shale Gas Extraction (Jackson, et al. 2013)

The third study published by researchers at Duke University (Jackson, et al. 2013) addressing hydraulic fracturing focuses on identifying potential sources of stray gas (methane gases which escape from oil and gas wells as a result of casing leaks and/or methane which migrates from deeper formations as a result of enhanced deep-to-shallow hydraulic connections) in drinking water wells. The researchers analyzed samples from 141 drinking water wells (the data collected from the first study (Osborn, et al. 2011), plus new data from an additional 73 wells across the Appalachian Plateaus of northeastern Pennsylvania. The study characterized three factors previously proposed to influence methane concentrations in the shallow groundwater of the region: (1) distance to gas well, (2) proximity to valley bottom streams (e.g., waterbodies located at the lowest topographic points), and (3) proximity to the Appalachian Structural front, which is the most westerly major fold or fault of the Appalachian mountain range.

Dissolved methane was detected in 82 percent of the samples. The authors’ review of the data suggests that methane concentrations were on average six times greater for wells located within 1 kilometer of natural gas wells. Ethane and propane concentrations were also greater in drinking water wells within 1 kilometer of natural gas wells. The study found that neither the proximity to valley bottom streams nor the distance to the Appalachian Structural front (signifying the degree of tectonic deformation) showed a statistically significant correlation to the methane concentration. The study also notes that the threshold that the US Department of the Interior suggests for considering remediation is 10 mg/L of dissolved methane in the water, which is much higher than the levels detected in the wells used in this study. Because methane is not toxic, there is no primary or secondary drinking water standard. The 10 mg/L value to consider remediation is based on the potential for methane accumulation in confined spaces.

In addition to correlating methane concentrations to location, the study analyzed the isotopic signatures of the detected methane to determine its source (either *biogenic* -- formed at shallow depths from decomposition of organic material or sewer gases; or *thermogenic* -- formed at elevated temperature and pressure, typically in association with oil and gas deposits). The results of the analysis showed some thermogenic signatures were detected in drinking water wells located less than 1 kilometer from gas wells. The authors then, suggesting that the methane was derived from deeper source rock, potentially found at the depths targeted for used in natural gas extraction.

However, the results also showed detections of biogenic methane in wells located near gas wells. Based on results of the study (both the comparison to location of natural gas wells and the isotopic analysis), the researchers concluded that the most likely explanation for higher dissolved gas in drinking water wells was faulty casings or cement seals on natural gas wells (i.e., issues associated with well integrity).

The study then cites that the PADEP issued 90 violations for faulty casings on 64 Marcellus Shale gas wells in 2010 and 119 Marcellus Shale gas wells in 2011. This attempt to show a nexus of shallow methane concentrations to well construction is unsubstantiated. Other potential mechanisms for methane occurrence cited in the study include increased deep-to-shallow hydraulic connections as a result of hydraulic fracturing, and intersecting abandoned oil and gas wells. The researchers dismiss the latter as historical drilling activity is minimal in the study areas.

We note that all samples for this study were collected after gas drilling had already begun, so no baseline data on methane levels prior to drilling was available.

Evaluation of Methane Sources in Groundwater in Northeastern Pennsylvania (Molofsky 2013)

In response to the three studies published by researchers at Duke University, a group of researchers funded by Cabot conducted a separate study to evaluate the presence of methane in water wells within the Marcellus shale. The results of the study were first published in the Oil and Gas Journal in December 2011, in an article entitled, "*Methane in Pennsylvania water wells unrelated to Marcellus shale fracturing".* Following peer review of the study, it was republished in June 2013, in the National Groundwater Association Journal.

The purpose of the study was to evaluate determine whether elevated methane concentrations in water wells in Susquehanna County, Pennsylvania directly resulted from shale gas development. The study investigated whether reported methane concentrations above the PADEP action level (7 ppm/liter or mg/l) in local private wells supplies exhibited signatures similar to Marcellus shale production gases or those of gases sampled in the conventional gas wells in the overlaying shallower formations. The evaluation represents a regional-scale assessment of trends observed in geochemistry in a large dataset spanning a 3-year period. Accordingly, background methane and groundwater quality survey data were also evaluated in conjunction with geologic and historical information to provide additional clarity of better understand the potential source of elevated methane levels in these drinking water wells.

Data collected and analyzed as part of the study included geological data on regional structure and stratigraphy, studies on aquifer dynamics and geochemical dynamics, and documentation of the historic occurrence of methane. Data from 1,701 water wells in Susquehanna County were evaluated in the context of the other data sets to determine the presence and distribution of elevated methane concentrations and other groundwater parameters, part of an extensive pre-drill water well survey conducted by Cabot between 2008 and 2011 in accordance with PADEP's pre-drill protocol to collect data from any water well located within 1,000 feet of a proposed gas well. In 2010, the sampling program was expanded to include all water wells within 2,500 feet of proposed gas well sites in anticipation of revised Pennsylvania Department of Environmental Protection guidelines.

Pre-drill analytical data indicated that methane is common in the subject drinking water aquifer, with approximately 78 percent of the samples containing dissolved methane. In only 3.4 percent of the pre-drilling samples with methane, the 7mg/L PADEP action level was exceeded. The authors note that this finding is consistent with historical documents dating back to the 1800s that indicate that naturally-occurring methane has been present in the shallow subsurface as demonstrated by the presence of shallow gas shows, historic gas fields, and bubbling springs and wells (Ashley and Robinson 1922, Lohman 1937, Lohman 1939, White 1881, all as cited in Molofsky, et al. 2013).

The study also compared the water quality data to topographic data to determine if there was a statistically significant correlation between the topographic location of a well and the methane concentration. The results of this analysis showed that elevated methane concentrations did correlate with topography, with elevated concentrations of methane found in water samples; samples exceeding the Pennsylvania Department of Environmental Protection action were disproportionately located in valleys versus upland areas. Samples with concentrations of methane greater than 1ppm/L also exhibited relatively elevated concentrations of barium, chloride, manganese, pH, sodium, strontium and TDS and relatively lower levels of sulfate and calcium.

The study concluded that the link between increased methane concentrations and elevated sodium chloride indicates that the wells with higher methane are connected to deeper groundwater aquifers that have experienced longer groundwater residence times and, therefore, had more time for rock-water interaction or interaction with deep sodium-chloride rich formation waters brines.

The study also concluded that the correlation of methane concentrations with topography rather than areas of active shale gas extraction activities indicates that the use of hydraulic fracturing in northeastern Pennsylvania has not caused a widespread gas migration into the shallow subsurface. However, the study does note that there have been instances of stray gas migration in Pennsylvania, Ohio, and New York associated with the accumulation of gas pressure within and around the sides of annular spaces of gas well casing strings, which have resulted in localized effects on water quality rather than large scale, regional impacts (Molofsky, et al. 2013).

Isotopic analyses on methane was not performed for all the 1,701 pre-drill water samples evaluated in this study to determine the origin of the methane detected in drinking the water wells. However, a review of historical, topographical, and geological data by the authors suggest that the methane is thermogenic in nature, most likely originating in the deposits overlying the Marcellus Shale (resulting from the long history of conventional gas production in Pennsylvania) or biogenic, microbial, methane resulting from the long residence time in anaerobic groundwater units.

Based on a comparison of Marcellus production gases to the gases encountered in the overlying Upper and Middle Devonian conventional gas formations, the study noted that the PADEP has determined that the gases encountered in the different formations have unique isotopic signatures, although both produce thermogenic methane. Although the isotopic signatures are similar they are distinguishable, possibly due to the increased thermal alteration experienced by the organic matter in deeper formations, leading to more positive carbon and hydrogen isotopic values for methane gas (Molofsky, et al. 2011).

Expanding upon the initial regional study comparing methane concentrations to topographic position, a follow-up assessment was conducted in 2013. The PADEP collected 15 water samples as part of the ongoing stray gas investigations in Dimock Township. The isotopic composition of these samples was determined to indicate the source of the methane using isotopic analysis. The results of the analysis indicate that isotopic ratios of the gases present in local Dimock Township water supplies are most consistent with the gases sampled in the annular spaces of wells that intersect the overlying Middle and upper Devonian formations, rather than the Marcellus production gas. The methane concentrations in these water wells can be explained without a contribution from the deeper Marcellus shale (Molofsky et al. 2013). Although it is possible that there is some mixing of small percentages of gas from the deeper Marcellus shale, the study concludes that this assumption is not supported by the historic data and the geographic distribution.

A Geochemical Context for Stray Gas Investigations in the Northern Appalachian Basin: Implications of Analyses of Natural Gases From Neogene-through Devonian-age Strata (Baldassare, et al. 2014)

This study evaluates the potential source of methane in the shallow subsurface and potable water supplies in northeastern Pennsylvania. The study noted that the source of methane is both naturally-occurring and anthropogenic. Examples of anthropogenic methane observed in this zone could be attributable to ineffective include faulty well construction. If those situations occur in areas of high pressure and high formation permeability, the gas could potentially migrate from well bores to an aquifer.

The study notes that these long-term elevated reservoir pressures are not related to hydraulic fracturing. The study confirms also notes that the well construction and well integrity issues can be identified by diagnostic tests and then remediated. The study states the PADEP investigated 17 state-wide stray gas incidents in 2009, 35 in 2010, and 37 in 2011 and determined no evidence linking stray natural gas migration to hydraulic fracturing of the Marcellus Formation. This study analyzed 2,274 gas and water samples from a five-county study area in northeastern Pennsylvania for molecular composition and stable isotope (carbon and hydrogen) compositions of methane and ethane. Samples were collected from mud gas logging programs during drilling of Marcellus shale-gas wells and baseline groundwater quality testing programs prior to gas-well drilling. The geochemical data were evaluated to constrain gas origin, alteration processes, and thermal maturity. Evaluation of the geochemical database indicate revealed that both biogenic (microbial, mixed microbial) and thermogenic methane occurs in some shallow aquifer systems. The data indicate naturally-occurring thermogenic gas within, or in close vertical proximity to, potable aquifer systems in the study area. Thermogenic gases could not be attributed to gas well or other anthropogenic activity except for one specific data point in an area where previous studies documented gas storage facility leakage. The study also found that the gas occurrences predate Marcellus Formation drilling activity (Baldassare et al. 2014).

Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers (Myers 2012)

Myers (2012) used a groundwater flow model to test whether hydraulic fracturing fluids could migrate through natural vertical pathways from fractured shale to shallower drinking water aquifers. The study focuses on natural gas extraction in the Marcellus shale and analyzes two potential hydrogeological pathways – advective transport through bedrock and preferential flow through fractures. Myers assigned various factors related to flow through bedrock and fractures in order to model contaminant flow. These factors included groundwater flow; conductivity of the substrate; changes in conductivity of the substrates based on regional shale hydrogeology; high density fracturing and faulting, and high-volume injection.

The study acknowledges that the model is an over simplification of simplifies a complex underground system, but the results suggested a small potential of connectivity resulting in decreased transport timing of gas or liquids from the Marcellus shale to shallower zones. Myers postulates that the decreased timing for migration could be measured in a few years (Myers 2012).

Myers' study was a modeling exercise that is theoretical in nature and not tied to specific measured properties. Following publication of the study, critiques of its assumptions and conclusions were published, with an emphasis on the non-representative nature of the factors used in the model (Siegel 2012). The three specific criticisms of the paper are summarized below:

- Myers' includes mistaken assumptions about the rocks above the Marcellus shale. Myers' model assumes that the formations above the Marcellus shale consist primarily of sandstone when most of the rock above the Marcellus is comprised of dense, dry shale.
- Myers' model contains mistaken assumptions with respect to movement of groundwater. The model assumes that water in the Marcellus naturally moves upward via artesian pressure, which does not follow hydrogeological principals established in the Appalachian region.
- Myers' model exaggerates assumed fracture lengths. Myers' assumes that faults or fissures will move formation water upward for 1 to 2 miles and that the pressures from hydraulic fracturing will open up new fractures that will remain open for this length. Siegel (2012) argues that this assumption is not grounded in science or experience in the region.

In addition to Siegel (2012), the Pennsylvania Council of Professional Geologists published a technical rebuttal to the article on their website. In their rebuttal the authors state:

"[T]he author's selective use of modeling parameters, misrepresentation and/or misapplication of existing technical references to justify his modeling scenario, and omission of certain key data and widely accepted principles regarding subsurface geology and fluid flow through porous media, highlight two major deficiencies of this work: 1) lack of objectivity, and 2) lack of understanding how to develop a credible hydrogeological conceptual site model" (Carter et al. 2013).

The specific criticisms of the modeling conducted by Myers in this rebuttal are the same as those summarized in the Siegel (2012) critique (Carter et al. 2013).

Baseline Groundwater Quality from 20 Domestic Wells in Sullivan County, Pennsylvania, 2012 (Sloto 2013)

In 2012, the US Geological Survey (USGS), in conjunction with the Pennsylvania Geologic Survey, performed a study to establish baseline groundwater quality in central and southern Sullivan County, Pennsylvania prior to hydraulic fracturing in the area. Sullivan County is located in north central Pennsylvania and is underlain by the Marcellus Shale, approximately 6,000 to 9,000 feet below ground surface. All of the residents of Sullivan County rely on groundwater as a source of drinking water. Since 2006, 67 natural gas wells have been drilled in the Marcellus Shale in Sullivan County, mostly in the northern portion of the county. The natural gas producers collected some baseline groundwater quality data for water supply wells in the northern portion of the county prior to gas-well drilling.

Water samples were collected from 20 private domestic wells and analyzed for 47 constituents and properties, including nutrients, major ions, metals and trace elements, radioactivity, and dissolved gases, including methane and radon-222. The data was compared to EPA maximum contaminant level (MCLs) for primary drinking water standards as well as secondary MCLs. Primary MCLs are set to address potentially adverse health effects in drinking water, while secondary MCLs are set for aesthetic reasons such as taste and odor in drinking water. There is neither a primary or secondary MCL for methane because it is not toxic. The federal standard of 10 mg/L is based on physical hazards and not health hazards.

The results identified showed that only one constituent in one sample (gross alpha radioactivity) exceeded the MCL for primary drinking water standards. The other water quality issues involved aesthetic considerations, such as poor odor and taste caused by elevated total dissolved solids (TDS) and metals. TDS and chloride exceeded the secondary MCL in one sample each. Four samples exceeded the secondary MCL for iron and seven for manganese.

The EPA does not currently regulate radon-222 in drinking water, but in 1999 the EPA had proposed an MCL of 3,000 pico-Curies per liter (pCi/L). Water samples from 17 of the 20 wells sampled exceeded this proposed limit. In addition, two water samples exceeded the proposed alternate MCL for community water systems that have enhanced indoor air programs (4,000 pCi/L).

Dissolved methane was detected in samples from seven wells. Detected concentrations of dissolved methane were less than 0.07 mg/L in five of the samples, and 4.1 and 51.1 mg/L in the other two. The isotopic ratios for these samples fell into the range for a thermogenic source. The water from these two wells also had the highest concentrations of arsenic, boron, bromide, chloride, fluoride, lithium, molybdenum, and sodium.

These data are from a baseline, pre-drilling evaluation. As such, they demonstrate the natural levels of these compounds in this area.

Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies (Boyer, et al. 2012)

A Pennsylvania State University study sponsored by the Center for Rural Pennsylvania in 2010 and 2011 provided results of a geographically broad analysis of water quality in private drinking water wells in rural Pennsylvania before and after hydraulic fracturing. The study also documented the status of enforcement of existing regulations and the voluntary measures used by homeowners in the area.

The researchers assessed samples collected from 233 water wells located within active Marcellus gas drilling areas before and after drilling, as well as control samples from wells in areas where no drilling occurred nearby. The study was implemented in two phases; the first phase of the study focused on 48 wells located within approximately 2,500 feet of a gas well, and the second phase of the study expanded the study area to include an additional 185 private wells within 5,000 feet of an active Marcellus well pad. Phase 1 included both pre- and post-drilling data, whereas Phase 2 included only post-drilling data.

The pre-drilling results of Phase 1 indicated that about 40 percent of the wells exceeded at least one drinking water quality standard (MCL), primarily for coliform bacteria, turbidity and manganese. The pre-drilling data also documented methane in 20 percent of the samples, although levels were generally significantly below EPA advisory levels for physical hazards (10 mg/L).

Comparison to post-drilling data did not detect influences from hydraulic fracturing on nearby water wells. TDS, chloride and barium are three of the most commonly used water quality parameters to indicate potential effects from gas well drilling. These parameters tend to be indicator constituents in from drilling or completion activities. When compared to typical background concentrations, these parameters can be used as identifiers of a potential release to the environment. The study concluded that there was little change in pre- and post-drilling concentrations for these indicator compounds. All post-drilling exceedances of the MCL for TDS also exceeded the MCL before drilling. Trends in chloride were similar; there were generally no increases in post-drilling data, and wells that exceeded the MCL post-drilling also exceeded it prior to drilling. Only one well exceeded the MCL for barium, but water in this well exceeded the MCL both before and after drilling. Also, the highest concentration for barium was sampled in a control well.

An analysis of the methane concentrations in pre & post drilling samples showed no statistical variation. Moreover, there was no statistically significant increase in methane concentrations after drilling and no correlation of methane accumulations with distance from the drilling location. Dissolved methane was reported to increase at one drilled site; however, this site exhibited a moderate level of methane before drilling.

There were minor increases in sodium, bromide, chloride and TDS levels noted in post drilling samples. This minor increase could be due in part to poor construction of the water wells. This possible mixing was, according to authors, potentially due to the faulty construction of the water wells and potentially suggests that well water mixed with waste fluids, flowback, or brines. The State of Pennsylvania does not have statewide standards for construction of private drinking water wells and many of the water wells tested lacked the recommended construction standards (e.g., casings, sanitary seals and grout seals, etc.) which the authors suggest likely contributed to impairments of certain water quality standards.

Monitoring of Air, Land, and Water Resources During Shale Gas Production (US DOE 2013)

The US Department of Energy's National Energy Technology Laboratory (NETL) is conducting a comprehensive assessment of the environmental effects of shale gas production. One of the primary objectives of the study is to monitor for signs of groundwater impacts contamination as a result of hydraulic fracturing operations in the Marcellus Shale. The study is being conducted at two industry-provided sites: one in Greene County, Pennsylvania and one in Washington County, Pennsylvania.

Greene County overlies a producing Upper Devonian gas field at a depth of approximately 4,000 feet. This producing formation which is approximately halfway between the Marcellus Shale and the surface. Existing wells in the Upper Devonian were used as part of the study to monitor for zonal isolation and evidence of communication with the hydraulically fractured areas in the deeper Marcellus shale formation (which is at approximately 8,000 feet below ground surface). Eight Marcellus Shale gas wells had already been drilled at the site when NETL began monitoring but had not yet been hydraulically fractured.

This study by the NETL marks the first time that a government agency used tracers included in the fracking fluid to regularly monitor for chemical migration. No results or conclusions have been published to date.

The second portion of the study will monitor a full suite of potential environmental impacts associated with hydraulic fracturing before, during, and after site development and fracturing. More than a year of environmental monitoring will occur prior to site construction and drilling.

This study marks the first time that a government agency used tracers included in the hydraulic fracturing fluid to regularly monitor for migration. At the Greene County site, man-made perfluorocarbon tracers were injected along with the hydraulic fracturing fluids into one of the Marcellus Shale wells and the natural gas produced from the overlying Upper Devonian wells was monitored for evidence of the tracers. During the hydraulic fracturing operation, pressure in the Upper Devonian wells was monitored to detect pressure increases that might suggest communication with an overly pressurized Marcellus Shale. In addition, produced water chemistry and gas chemistry (including strontium isotope chemistry) were sampled and analyzed in two vertical Marcellus wells and six Upper Devonian gas wells for indications of communication with the Marcellus Shale (US DOE 2013).

NETL issued a press release in July 2013 stating that at that time the study was still in early stages. Preliminary conclusions in the press release state that “while nothing of concern has been found thus far, the results are far too preliminary to make any firm claims. We expect a final report on the results by the end of the calendar year.” Media coverage at the time of the press release quote NETL researcher geologist, Richard Hammack, as saying that the tracer-injected hydraulic fracturing fluid remained thousands of feet below the shallow areas that supply drinking water. No further information has been released since that time (Begos 2013).

The second portion of the study in Washington County will monitor a full suite of potential environmental impacts associated with hydraulic fracturing before, during and after site development and fracturing. The Washington County site is offset from current production areas, allowing for more than a year of environmental monitoring to establish baseline conditions prior to site construction and drilling. Monitoring will continue during site development and drilling, completion and beyond to determine whether any changes take place that may be attributable to any stage of the shale gas development process. The environmental parameters monitored will include air quality, fugitive methane emissions, migration of production fluids, and impacts on avian populations. Several months of baseline data have been collected. Timing of site development is pending depending on the industry partner (US DOE 2013).

Generation, Transport, and Disposal of Wastewater Associated with Marcellus Shale Gas Development (Lutz, et al. 2013)

This study presents a review of data from approximately 2,200 wells located throughout the State of Pennsylvania. The data was analyzed to examine the potential impacts of natural gas operations on produced water development in the Marcellus Shale. Although not directly related to hydraulic fracturing, the study evaluates the secondary effect of an increase in the number of wells facilitated by the use of the approach.

Statewide natural gas and wastewater data from 2000 through 2011 were downloaded from the PADEP, Bureau of Oil and Gas Management website. The data are self-reported by gas well operators in accordance with Pennsylvania law and represent best available information on conventional and Marcellus well development and produced water generation.

As stated by the study authors, extracting shale gas generates large volumes of water; however the volume and quality are poorly constrained. Therefore, the objectives of the data review were: (1) to quantify drilling, flowback and brine wastewater volumes produced by shale gas wells and conventional wells; (2) to assess changes in the cumulative wastewater volume resulting from the rapid expansion of Marcellus wells; and (3) assess how wastewater disposal options are evolving as the shale industry develops. Some data is included from conventional gas wells, but still completed through hydraulic fracturing. The study notes that it excluded data from conventional wells where no flowback volume was reported, indicating that the well had not been hydraulically fractured.

The rapid increase in produced water is a consequence of the resource size rather than the methods employed (e.g., hydraulic fracturing). The existing wastewater disposal capacity is being quickly saturated, even though less than 1 percent of the Marcellus Shale has been explored. As such, produced water disposal, or beneficial reuse, will be an important issue to study and address as the Marcellus Shale is further developed.

With regard to the first study objective, the data review indicated that the average Marcellus Shale well generated six times more drilling wastewater than the average conventional well (0.654 million liters for a Marcellus Shale well compared to 0.116 million Liters for a conventional well), and flowback from a conventional well was also much less (approximately 0.107 million Liters on average) than that from a Marcellus Shale gas well (approximately 1.68 million Liters on average). Completing shale gas wells uses more water than conventional wells because of hydraulic fracturing.

However, the report notes that Marcellus Shale wells produce less wastewater per unit of gas recovered compared to conventional natural gas wells drilled in Pennsylvania. When taking into consideration the amount of natural gas produced, shale gas wells produced only approximately 35 percent the volume of wastewater per unit of gas recovered as compared to a conventional well in Pennsylvania (Table A-3).

Table A-3 -Comparison of Wastewater Produced during Drilling, Hydraulic Fracturing, and Production Stages of a Well between Conventional and Marcellus Wells (Lutz 2013)

Well Type	Drilling[a] (Lx106 per well)	Flowback[a] (Lx106 per well)	Brine[b] (Lx106 per well)	Total Wastewater[c] (Lx106 per well)	Gas Produced[3] (Lx106 per well)	Wastewater: Gas Ratio (L Waste per MMBTU gas)
Conventional	0.116	0.107	0.291	0.514	1,050.1	13.4
Marcellus	0.654	1.683	2.874	5.211	30,038.7	4.8

[a] Values are for the total drilling and flowback volumes produced by each well.
[b] Values were summed over the first four years of brine production.
[c] Values based on summing estimates for drilling, flowback, and brine volumes.
[d] Energy content of gas based on data from US EIA (2007): approx. 36.2 BTU per L gas; MMBTU = 1x106 BTU

With regard to the second study objective, the study notes that prior to development of the Marcellus shale, the total wastewater produced in the state of Pennsylvania by all conventional wells was approximately 800 million Liters per year and that consisted of primarily (~86 percent) brine. With the expansion of development in the Marcellus Shale, the amount of wastewater produced has increased by over 500 percent. For purposes of this study the water is calculated under three definitions; Drilling fluids, Flowback, and Brine. Drilling fluids are those fluids used during the actual drilling of a well. Flowback is generally considered those fluids that come out of the well during the first 30 days after completion. Brine water is also referred to Produced water, being the waters produced after flowback waters are recovered. Because most of the wells in the Marcellus Shale are new (1 to 2 years old) and new wells are drilled each year, the wastewater is comprised approximately 44 percent brine, 44 percent flowback and 12 percent drilling fluids. Recent estimates predict that the number of active wells will quadruple in the region by 2014. Assuming that no brine is produced following the fourth year in operation, the study estimates that the cumulative amount of wastewater produced by all wells in the Marcellus region will exceed 5,370 million liters in 2014 (more than 10 times the cumulative wastewater production prior to development of the Marcellus Shale).

With regard to the third study objective, the study identifies that the rapid increase in volume of wastewater has exceeded exceeding current capacity (at a local or regional level) for disposal/reuse options. Underground injection for wastewater is limited in the Marcellus region because the geology does not allow for it. Four primary alternate disposal methods are available: 1) treatment at a municipal wastewater treatment facility; 2) treatment at a private industrial wastewater facility; 3) transporting the water across state lines to underground injection facilities; or 4) partial treatment and recycling of water in subsequent hydraulic fracturing operations (Figure A-3 Each of these is discussed in the following paragraphs.

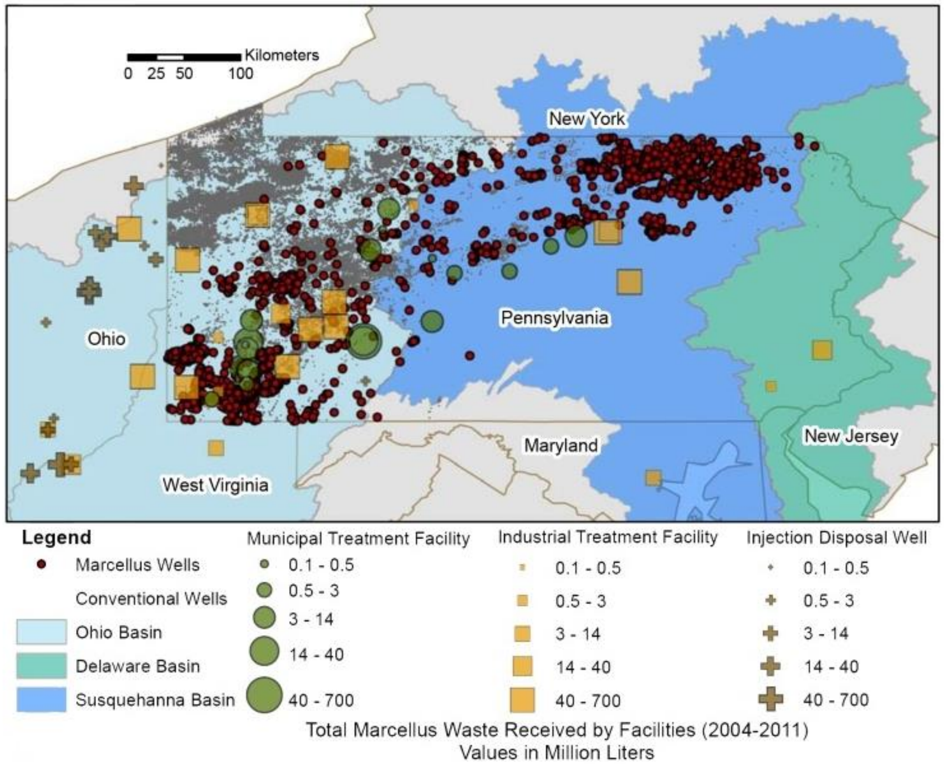


Figure A-3. Map of Wells and Disposal Facilities Comparing Volume of Wastewater Received (Lutz, et al. 2013)

Produced water generated from shale gas wells often has elevated TDS, which can exceed the permit limits of municipal sewerage treatment facilities. Prior to the current surge in natural gas development, the produced water volumes were relatively low, so that the TDS was diluted by the larger sewerage water volumes of publicly owned treatment works (POTWs) that processed large volumes of waste water (sewage and combined sewage/stormwater inflows). With the increase in waste water production within the Pennsylvania, it became apparent the current municipal treatment facilities were unable to effectively manage the water intakes and treatment required. As a result, industry and the state worked cooperatively to eliminate continued use of these facilities for unconventional wells. With the current increase in the volume of produced water going to municipal treatment works there is far less dilution than before. As the ability of municipal treatment plants to accept produced water has reached a limit, other methods and locations for disposal of this water are now being utilized in Pennsylvania; produced water is now also taken to industrial wastewater treatment facilities in western Pennsylvania. However, these too have TDS limits, and can take a limited quantity of high TDS water.

The paper also reports that some produced waters are also discharged to rivers following treatment at municipal and industrial facilities. The PADEP noted a decline in surface water quality resulting from the discharge of effluent with elevated TDS and enacted stricter effluent standards in 2010. However, this method of disposal is no longer utilized in the state and operators are largely depending on recycle and reuse options. Operators do transport some wastewater out of state to underground injection facilities in neighboring states. Most of the closest underground injection facilities are located in Ohio. The study hypothesizes that disposing of produced water in Ohio could cause a spatial shift - interbasin transfer – as a result of disposal, meaning that water (albeit wastewater) is produced in one water basin and disposed of within another water basin. The study also suggests that trucking wastewater offsite increases risk of accidental surface spills.

Recycling produced water for subsequent hydraulic fracturing operations is another potential method used by industry in water management practices. In 2011, 56 percent of wastewater (mainly flowback water) was recycled for future well development. The study notes the following challenges to recycling wastewater: high concentrations of ions that can result in sulfate-, carbonate-, and iron-based scales that impede gas flow, abundant anaerobic bacteria that can cause corrosive byproducts and biological fouling, and variations in salinity that can compromise well integrity by affecting clay shrinking and swelling within the formation.

Shale Gas Development Impacts on Surface Water Quality in Pennsylvania (Krupnick and Olmstead 2013)

This study presents the results of a large-scale examination of the potential effects of shale gas development on surface water associated with the discharge of flow back and produced water from oil and gas operations. The study notes that although the potential for surface water impacts are discussed in the literature, little empirical analysis of the data has been published conducted. However, the potential for impacts has strongly influenced the regulatory framework for shale gas development in some states.

The study focuses on the Marcellus shale region in Pennsylvania and estimates the effect of shale gas wells and the release of treated shale gas waste by permitted treatment facilities on observed downstream concentrations of chloride and total suspended solids (TSS). Data was retrieved from publically-available EPA databases, including approximately 20,300 water-quality observations collected from hundreds of water quality monitors across Pennsylvania between 2000 and 2011. The study analyzed the water quality data in conjunction with data about shale gas well locations obtained from the PADEP Pennsylvania Department of Environmental Protection and DCNR Department of Conservation and Natural Resources, as well as documentation of shipments of shale gas wastes to treatment facilities and water body characteristics obtained from PADEP Pennsylvania Department of Environmental Protection and EPA. The study analyzed temporal and spatial variation in the location of wells and waste treatment facilities to evaluate the impacts on downstream water conditions quality.

Concentration of chloride ions and TSS were used as indicators of water quality impacts from shale gas development because chloride is commonly associated with produced water from shale gas development and TSS is associated with potential stormwater discharges during construction of infrastructure, as well as shale gas wastewater treatment (although most treatment facilities are designed to remove solids). The TSS results are not directly applicable to the effects of hydraulic fracturing on water resources. Data were collected for both constituents at a large number of the water quality monitoring sites from which data was retrieved. There are a variety of other sources that have the potential to contribute to chloride and TSS (e.g., road salt contributes to chloride concentrations during winter months), which were controlled in the data analysis by considering average historical concentrations at each monitoring location over time, including prior to development of the Marcellus Shale.

The study results indicate that chloride concentrations did not increase at monitoring locations downstream of shale gas wells in comparison to data retrieved from monitoring sites upstream of gas wells. However, an increased concentration of chloride ions was observed in water quality samples collected downstream of treatment facilities that accept produced water. When examining only chloride ions, the results suggest that accidental releases from well sites directly to surface water are not a significant threat to surface water quality; however the of significant volumes of produced water at POTWs which are not capable of treating the salinity could impact adversely affect surface water quality downstream of the treatment facilities. (Chloride concentrations downstream of treatment facilities that do not accept shale gas wastewater were not analyzed as part of the study). While these observations are not a direct result of hydraulic fracturing, it is a part of the “life cycle” analysis of water management within the region associated with the industry. This is not a direct result of hydraulic fracturing, but part of the increase in wells operating in the area.

Geochemical Evaluation of Flowback Brine from Marcellus Gas Wells in Pennsylvania, USA (Haluszczak, et al. 2012)

The purpose of this study was to document whether hydraulic fracturing operations result in increased salinity in flowback water in Marcellus gas wells. Flowback water was defined as any fluids that returned to the surface of a well within 2 weeks of hydraulic fracturing, whereas produced water was defined as the remaining fluid that flows to the surface after the initial 2-week period following a hydraulic fracturing operation. In general, the concentrations of most inorganic components of flowback water (including chloride, bromide, sodium, potassium, and calcium) increase over time after hydraulic fracturing. The current primary hypothesis is that the dissolution of constituents from the shale by the water injected during hydraulic fracturing results in increased concentration of salts in flowback waters (as described in Blauch et al. 2009, cited in Haluszczak, et al. 2012).

Haluszczak et al. (2012) suggest an alternative hypothesis that hydraulic fracturing releases in- situ brines, or formation brines, which have been found to be produced from most oil and natural gas wells in Pennsylvania. To test this hypothesis, the study compared the following data:

- Analytical results from brines from 40 conventional oil and gas wells in Pennsylvania, which were drilled vertically and produced from a sandstone formation;
- Analytical results from flowback water from 22 Marcellus shale gas wells collected by the PADEP Department of Environmental Protection and the Pennsylvania’s Bureau of Oil and Gas Management to establish baseline characterization of the flowback waters;
- Analytical results from 17 flowback samples collected from two Marcellus shale gas wells over a 45-day period and;
- Analytical results of flowback samples collected from 8 hydraulically fractured wells located through Pennsylvania, as reported in a study by the Marcellus Shale Coalition, reported in a Gas Technology Institute publication.

The results of the comparison indicate that flowback water from wells that have been hydraulically fractured resemble brines that are produced from conventional wells. The ratio of bromide to chloride indicate that brines from both hydraulically fractured and conventional wells formed as a result of seawater evaporation and subsurface mixing with seawater, freshwater, and/or injected fluids. Trends and relationships in brine composition further indicate that increased salt concentration in flowback water is not mainly caused by dissolution of salt or other minerals in rock units, but rather that the flowback water represents a mixture of injection water with naturally occurring highly saline brines.

Water Pollution Risk Associated with Natural Gas Extraction from the Marcellus Shale (Rozell and Reaven 2011)

The study did not focus on the effects of hydraulic fracturing on water resources, but the associated oil and gas activity. This study summarizes the results of a probability analysis assessing the likelihood of water impacts contamination from natural gas extraction in the Marcellus Shale through five different potential pathways:

- Spills during transport;
- Well casing leaks;
- Migration through fractured rocks from the producing zone to upper level aquifers;
- Drilling site spills due to improper handling, and/or leaks from storage tanks and retention ponds; and,
- Wastewater disposal.

A computer-generated probability bounds analysis was used to characterize the risk associated with each pathway. Although the study relied entirely on publicly-available data, the authors noted that in many instances data is sparse for Marcellus shale gas extraction, and the drilling process that was used may not be recorded. Therefore, the authors note that there is uncertainty regarding the appropriate model inputs and the resulting outputs.

Acknowledging this limitation, the model results indicate that the potential contamination risk associated with wastewater disposal is several orders of magnitude greater than any of the other possible pathways evaluated. Risks associated with transportation were characterized as negligible compared to other potential pathways. The risks and uncertainties associated with well casing failures and migration of constituents contaminants through unintended fracture networks were potentially substantial, but minor in comparison to the risk associated with disposal of wastewater. The risk of site surface impacts from contamination was modest, but the modeling indicated that a rare but serious retention pond failure could generate an acute local impact. Based on the potential impacts demonstrated by the model, the study concludes "it is very likely that an individual well could generate up to 200 cubic meters (m^3) of contaminated fluids." Based on the results of the risk analysis (presented in Table A-4 below), the study concludes that future research efforts should be focused primarily on wastewater disposal options, as this is the pathway that demonstrated the greatest risk, and that efforts should focus specifically on the ability of industrial and municipal wastewater treatment facilities to remove constituents associated with this water stream contamination (Rozell and Reaven 2011). This effect is not a direct result of hydraulic fracturing. Rather, the increased volumes of produced water result from increased numbers of operating wells.

Table A-4 - Comparison of Water Contamination Pathway Risks from Hydraulic Fracturing in a Typical Marcellus Shale Gas Well (as published in Rozell and Reaven 2011)

Pathway	Best-Case 50th Percentile Contamination Volume (m^3)	Worst-Case 50th Percentile Contamination Volume (m^3)	Maximum Epistemic Uncertainty Between Best and Worst Case (m^3)
Transportation	<0.01	0.3	0.6
Well casing failure	<0.01	9	60
Fracture migration	<0.01	225	270

Drilling site spills	<0.01	3	15,000
Wastewater disposal	202	13,500	26,900

The authors note several study limitations, including the potential that risk associated with wastewater disposal may be inflated. This bias is based on the model, which presupposes that deep underground injection is not a viable disposal option based on geologic conditions in the area. However, currently many natural gas operators in the region transport wastewater by truck to other locations where deep underground injection is possible. Another model assumption that could affect the risk analysis is that water sent to municipal wastewater treatment facilities is released untreated because these facilities are not designed to fully remove the high TDS concentrations. However, the authors note that treatment at a municipal facility would still reduce contaminants, even if they are not completely removed. Another limiting factor of the model is the lack of any timescale, thus requiring an improbable worst-case scenario that all impacts contamination would occur at a single point in time. The authors acknowledge that in a realistic scenario each potential contamination pathway has a different timeframe; transportation related spills would be likely to occur during initial construction and drilling, while casing issues would occur during production, and migration through a fracture network could take thousands of years. The rate of impact contamination is also not addressed in the model (Rozell and Reaven 2011).

Water Management Technologies used by Marcellus Shale Gas Producers: DOE Final Report (Veil 2010)

The US Department of Energy's NETL, in conjunction with Argonne National Laboratory, studied different water management options and their use in the Marcellus Shale. The report was produced as part of NETL's Environmental Program, and the purpose of the report was to gather data about wastewater management in the Marcellus Shale. To meet this objective, the Argonne National Laboratory contacted the Marcellus Shale Coalition, an industry group, and surveyed them about the wastewater disposal options utilized by organizations in the region. The survey revealed four primary disposal options that are currently being utilized by oil and gas operators:

1. Deep underground injection;
2. Treatment at municipal facilities;
3. Treatment at industrial facilities; and
4. Reusing in subsequent hydraulic fracturing operations (Veil 2010).

Results of the survey indicate that underground injection is the most frequently used disposal option, though there are few onsite or commercial disposal wells in the Marcellus Shale, due to restrictions of the geology. As a result, several Marcellus Shale operators send flowback water to commercial disposal wells in Ohio. None of the oil and gas operators surveyed discharge produced water directly into surface water bodies, as this would violate applicable regulations.

The second disposal option is treatment at publicly owned treatment facilities. Prior to the development of the Marcellus Shale, some regional treatment facilities would accept small quantities of produced water from oil and gas operators; however, the facilities are designed to remove suspended solids and materials other than salinity or TDS which limits their capability to treat produced water and meet state and federal guidelines. In 2010, the PADEP adopted discharge regulations placing limits on the volume of produced water the treatment facilities can accept, and many treatment facilities have conditions in their National Pollutant Discharge Elimination System (NPDES) permits that state that discharges from oil and gas operators cannot exceed 1 percent of the daily flow to prevent discharges with exceedingly high salinity. Therefore, the report notes that sending produced water to public treatment facilities is not a highly viable solution for producers in the Marcellus region. The capacity of the existing facilities has been taxed by the demand, and as a result more treatment facilities are being permitted and coming on-line.

The third treatment option currently in use is to haul produced water to industrial wastewater treatment plants, most of which are located in Pennsylvania. The more stringent discharge requirements adopted in 2010 allows for commercial disposal companies that already hold permits to be grandfathered in at their current levels, but new industrial dischargers face much more stringent TDS limits.

A fourth option is to reuse the produced water in future hydraulic fracturing operations. This is not always feasible because the TDS concentrations are higher than desired for hydraulic fracturing operations. The paper notes that various water treatment providers are working on TDS reduction technologies so that water can be recycled. The report concludes that if recycling can be practiced more widely throughout the region it could save producers money on disposal fees and trucking and reduce the volume of freshwater needed for hydraulic fracturing (Veil 2010).

Water Withdrawals for the Development of Marcellus Shale Gas Production (Abdalla and Drohan 2010)

A fact sheet produced by Pennsylvania State University summarized the water resources available in Pennsylvania and the potential impact of hydraulic fracturing in the Marcellus Shale to these resources. The study states that the “abundance of water in Pennsylvania is a double-edged sword for drilling in Pennsylvania. Water is needed for drilling, but drillers need to avoid affecting the numerous water wells, streams, lakes and other water bodies throughout the state.” According to the fact sheet, drilling wells requires up to 300,000 gallons per day per well in the Marcellus Shale, and hydraulic fracturing a horizontal well may require up to 4 to 8 million gallons of water across the span of one week, depending on how many hydraulic fracturing completions take place during that week[1]. Pre-drill water quality monitoring is already required in Pennsylvania, but the study suggests that pre-drilling water quantity data should also be required, because the rapid expansion of the Marcellus shale could put a strain on localized water availability.

The fact sheet describes the unique management of water in the Marcellus Shale region. Water quality is managed in cooperation between the PADEP, the Susquehanna River Basin Commission (SRBC), and the Delaware River Basin Commissions (DRBC), which seek to jointly manage water across multiple states. Both river Commissions have strict regulations regarding water withdrawals for natural gas development. In fact, as of 2010, the Delaware River Basin Commissions had not approved any natural gas well drilling in its jurisdiction. Regardless of the basin from which the water is sourced, the PADEP

[1] According to the Penn State Marcellus Center for Outreach and Research website, exploreshale.org, each drill site uses between 3 and 5 million gallons per hydraulic fracturing completion.

Department of Environmental Protection requires a water management plan included with every gas well permit which that specifies the water sources used for fracturing each well. For example, there are regulatory limits on how much water can be withdrawn from a stream. Users can also draw water from groundwater, but the majority of the water withdrawal in Pennsylvania (approximately 93 percent) comes from surface water sources.

Suggested additional updates to current regulations include requiring testing of water for certain fracturing fluid constituents, increasing the water quality protection bond required from drilling companies, and increasing the minimum setback of wells from streams and rivers (Abdalla and Drohan 2010).

Toward Strategic Management of Shale Gas Development: Regional, Collective Impacts on Water Resources (Rahm and Riha 2012)

This study evaluates the potential collective impacts of hydraulic fracturing on regional water resources in the Marcellus Shale region. The study states that the distributed nature of the shale gas resources and the potential for the continued rapid increase in hydraulic fracturing requires strategic planning and management of shale gas development. Moreover, the study purports that hydraulic fracturing operations can have a broad area of impact because materials and fluids from one site may be transported to other sites to be combined with fluids from other wells, and water withdrawals and waste disposal may both take place in locations remote from the well site.

This study focuses on the Susquehanna River Basin in New York State, because it contains the majority of the land that overlies the Marcellus Shale, and examines: (1) hypothetical water withdrawals and (2) treatment and discharge of wastewater to determine how differing policy approaches would have different regional impacts, highlighting the importance of taking a regional approach to regulation as opposed to a narrower project-specific approach.

The study examines hypothetical water withdrawal scenarios in the Susquehanna River Basin by identifying water withdrawal locations near USGS stream gauges. The study identified two different policy options that limited water withdrawal based on two different flow regimes. Both policies resulted in increased withdrawal prohibitions with decreasing stream size. and Neither prohibited withdrawal from large rivers because it was concluded that relatively small water withdrawals do not affect flows in large rivers. The study notes that more than one third of the gas-producing region is located within 10 miles of a large water source and more than half of the area is located with 20 miles of a large river. As such, the study suggests that it may be a prudent policy option to restrict water withdrawals to larger rivers and monitor flows at a regional scale rather than at the project specific level.

Wastewater treatment is another major public concern, especially in the Marcellus Shale region where underground injection is not a viable option. New effluent limitations on publicly owned treatment facilities limit this disposal option as well. The study examines three policy options with varying degrees of stringency with regard to permissible effluent discharge from publicly owned treatment facilities. The study determines that there are approximately 30 publicly owned treatment facilities in the study area, and that they have the capacity to treat water from 270 to 690 wells under the most relaxed policy option (wastewater may only comprise 1 percent of total daily flow) to only 30 to 140 wells under more stringent policy requirements (effluent limits of 500 mg/l TDS and technology pre-treatment requirements).

The study concludes that individual well pads may have limited or sporadic impacts to water resources, but the collective impact of rapid expansion may lead to further negative impacts, especially in areas that do not have a history of extractive industry. Therefore, the study suggests that it is important to assess approaches for analyzing and mitigating collective impacts (Rahm and Riha 2012).

NRDC's Evaluation of Hydraulic Fracturing Wastewater and Disclosure Regulations (Hammer and Van Briesen 2012)

In May 2012, the Natural Resources Defense Council (NRDC) published a report analyzing regulations related to produced water generated from hydraulic fracturing. The report focuses on wastewater disposal methods and regulations in Pennsylvania, and does not specifically address the effects of hydraulic fracturing on water resources.

1. The report states that the most common management options for shale gas produced water are:
2. Recycling for continued use during oil and gas operations;
3. Treatment and discharge to surface waters;
4. Storage in impoundments and tanks; and
5. Applying it to the land (e.g. dust suppression).

NRDC highlights environmental concerns associated with each disposal method, such as accidental spills when wastewater is temporarily stored in tanks or ponds on-site, inadequate treatment at publicly owned treatment facilities, or chemicals washing off roadways as a result of the land application method. Subsequently, NRDC recommends the following policy changes to strengthen regulations:

- Regulate discharges from treatment plants more strictly;
- Regulate hydraulic fracturing wastewater as a hazardous waste, either under the Resources Conservation and Recovery Act (RCRA) or state regulations;
- Only allow injecting of wastewater with hazardous characteristics into Class I hazardous waste wells, and strictly regulate Class II disposal wells in the interim; and
- Prohibit land application and temporary storage in impoundments and tanks.

NRDC notes that on-site recycling can have significant cost and environmental benefits by reducing freshwater consumption as well as the amount of wastewater requiring disposal. Additionally, the report NRDC notes that disposal by underground injection requires less treatment than other methods and creates the least risk of contaminating the environment. However, NRDC points out that this method can create risks of earthquakes and can require transportation over long distances.

NRDC encourages on-site wastewater recycling and does not identify any related policy recommendations directly pertaining to wastewater reuse other than noting that the benefits of reuse can sometimes be offset by the energy use and generation of concentrated residuals (Hammer and VanBriesen 2012).

In response to the report, in July 2012, the Secretary of PADEP Department of Environmental Protection issued a letter stating that "the Report is incorrect and inapplicable to Pennsylvania in many respects." The letter asserts that the report incorrectly characterizes wastewater disposal methods currently used in Pennsylvania and the associated regulations. The letter also mentions that the report underestimates the quantity of wastewater that is recycled (Pennsylvania Department of Environmental Protection 2012). In turn, the NRDC issued a response letter defending the report and continuing to urge PADEP to strengthen their regulations.

In addition to assessing wastewater regulations, in a separate article published in July 2012, NRDC conducted a comparison of disclosure regulations for hydraulic fracturing between states related to advance public notice requirements prior to hydraulic fracturing; disclosure of information concerning the geological and environmental context of the wells; comprehensive disclosure about the hydraulic fracturing "treatment" (i.e. pressures, volume and type of base fluids, depths, etc.); and disclosure about the volume of wastewater created as well as its storage, treatment and/or disposal. The article points to lack of public access to disclosed information even when disclosure regulations do exist, and poor compliance with and enforcement of regulation (McFeeley 2012).

FAYETTEVILLE SHALE

The Mississippian Fayetteville Shale covers 9,000 square miles in the Arkoma Basin of Arkansas and eastern Oklahoma. Shale gas development in Arkansas began in 2004, and production has increased steadily thereafter.

Shale gas development began in Arkansas in 2004, and the number of gas wells increased nearly 50-fold between 2005 and 2011.

Prior to 2010, no water sampling was performed in the state to study the potential link between groundwater contamination and gas production activities.

Shallow Groundwater Quality and Geochemistry in the Fayetteville Shale Gas-Production Area, North-Central Arkansas, 2011 (Kresse et al., 2012)

This study was conducted in cooperation between the USGS, the Arkansas Natural Resource and Oil and Gas Commission, Duke University, University of Arkansas at Fayetteville and Faulkner County. The study examined general water quality conditions and geochemistry of the shallow groundwater in the Fayetteville Shale gas production area in northern-central Arkansas. The study also evaluated the potential effects of shale gas drilling on water quality and geochemistry. To meet these objectives, water samples were collected from drinking water wells located throughout two counties in Arkansas, spanning approximately 850 square miles of the Fayetteville Shale, which comprises approximately one-third of the entire gas production area.

Because little to no monitoring had been collected or published prior to oil and gas development in the study area, the USGS interpretation of water-quality data collected from individual wells after gas production relies heavily on comparative analysis. In order to provide a more rigorous analysis, three approaches were used to identify potential changes in water conditions.

The first approach used is a direct comparison of contaminant constituents of interest source-water chemistry to that of shallow groundwater, in order to establish indicator constituents unique to the source water. The difficulty with this type of comparison is that many of the shallow domestic wells are completed in shale or influenced by shale chemistry, as are waters from the gas-producing formation. A total of 127 samples were collected from domestic water wells in Van Buren and Faulkner Counties and analyzed for major ions and trace metals. Van Buren and Faulkner Counties cover approximately one-third of actively producing Fayetteville Shale area. Both have rural areas with populations that rely entirely on private drinking water wells for potable water. A subset of samples was also analyzed for methane and carbon isotopes. The shallow groundwater in Van Buren and Faulkner Counties generally meets the primary standards for drinking water quality, although there may be secondary standards associated with taste and staining problems associated with elevated concentrations of iron, manganese and other metals in the water, a result of geochemical and microbial processes that occur in the aquifer.

The second approach is a statistical comparison of historical, pre-gas development shallow groundwater-quality data collected in the gas-production area to recent groundwater-quality data collected for this study. Water quality data was compared to historical shallow groundwater quality data from before gas drilling. Historical groundwater quality data were gathered from USGS database for 43 locations in the six counties that contain the bulk of permitted and active gas production wells: Cleburne, Conway, Faulkner, Independence, Van Buren, and White Counties, with data dating from 1951 through 1983. These data were limited with respect to trace metal chemistry and many of the major ions.

The most frequently analyzed constituent was chloride, which has been used as an indicator of migration of production waters into shallow groundwater zones because: (1) chloride is a conservative constituent in groundwater; it does not react with other minerals or adsorb to clays or organics, and also is highly soluble; and (2) chloride is elevated in gas-production waters associated with the Fayetteville Shale—flowback water has chloride concentrations that vary from approximately 2,500 to 5,000 mg/L and produced water can range upward to greater than 20,000 mg/L (Arkansas Oil and Gas Commission, unpublished data, April 4, 2012), similar to that of seawater. All but one historical sample included analysis of chloride.

The study results found higher concentrations for all major ions in the historical data sets compared to the recent analyses conducted for this study. For example, in the recent 127 groundwater samples collected, chloride concentrations ranged from 1.0 mg/L to 70 mg/L, with a median of 3.7 mg/L. In contrast, the historic data had a median chloride concentration of 20 mg/L and a maximum of 378 mg/L. The historical data is from a larger geographic area that may have a greater range in concentrations, but there is no indication of an increase in chloride as a result of recent well drilling and hydraulic fracturing.

The third comparison is of groundwater quality data in similar geologic and topographic areas outside of the gas-production area to data collected from wells within the gas-production area. The analysis compared the analytical data from 94 domestic-well sample sites less than 2 miles from active gas-production wells to 33 domestic-well sample sites greater than 2 miles from gas-production wells. The comparison attempted to discern any statistically significant differences in concentration of major ions,

This study conducted three analyses to determine if produced water from shale gas production migrated into shallow groundwater:

1. Analysis of major ions and trace metals from groundwater in gas-producing counties;
2. Comparison of chloride concentrations in historic data and current data; and
3. Analysis of methane and carbon isotopic composition

The results showed no indication of migration of produced water into shallow groundwater. Findings indicate that the geochemistry in the shallow drinking water aquifers result from natural processes.

trace metals, methane, or carbon isotopes between wells located greater than or less than 2 miles from active gas-production wells. The results showed that there was no statistically significant difference between wells closer to or further than 2 miles from active gas wells.

Methane and carbon isotopic composition were also analyzed in 51 of the recent 127 samples collected. Methane concentrations ranged from the detection limit of 0.0002 mg/L in 32 samples to upwards of 28.5 mg/L. Seven samples had methane concentrations greater than 0.5 mg/L. The carbon isotopic composition of the higher concentration samples indicates that in five of the samples the methane is derived from a biogenic source. Thermogenic isotopic composition was detected in five samples with very low methane concentrations (0.012 to 0.324 mg/L) but there was no statistical correlation with distance to nearest gas production wells.

The study concluded that the detection of low levels of thermogenic methane in groundwater samples from domestic wells located at great distances from production wells indicates that upward migration of thermogenic gas occurs naturally in the study area. Methane concentrations tended to increase with increased dissolved solids, indicating that there are stronger reducing conditions with increased rock-water integration in the aquifer.

Using both comparisons to historical data as well as distance from active production wells, data collected and analyzed for this study showed no indication of migration of produced water into shallow groundwater. The study findings indicate that the geochemistry in the shallow drinking water aquifers result from natural processes. These findings do not preclude the possibility that there may be mixing of produced water in domestic wells that were not sampled due to a spill or accidental release, but there is currently no evidence of such impact contamination. The results from this study provide a valuable baseline range and variation of geochemistry for the shallow groundwater in the area, which can be used to asses future potential changes to groundwater quality in the areas of gas production.

Geochemical and Isotopic Variations in Shallow Groundwater in Areas of the Fayetteville Shale Development (Warner, et al. 2013)

This study, conducted by researchers at Duke University, examined the possible degradation of groundwater quality in shallow aquifers that overly producing shale formations by comparing groundwater samples to flowback samples collected directly from Fayetteville shale gas wells. The study examined three potential pathways for contamination: 1) stray gas contamination; 2) migration of saline brines from depth due to hydraulic fracturing operations; and 3) migration of saline brines from depth via naturally occurring fractures. The study is the first to report such a comprehensive geochemical evaluation of possible shallow groundwater contamination outside of the Marcellus Shale basin.

One-hundred twenty-seven samples from domestic drinking water wells were compared to samples from six flowback and produced water samples from the underlying Fayetteville Shale. The water well samples were collected by USGS personnel, as described in Kresse et al. (2012). Flowback and produced water samples were collected by Arkansas Oil and Gas Commission personnel. Five flowback samples, collected within three weeks of hydraulic fracturing, and one produced water sample, collected approximately 50 weeks after hydraulic fracturing, were used in the study. In addition, the locations of natural gas wells were obtained from the Arkansas Oil and Gas Commission database. All samples were collected in Van Buren and Faulkner Counties, where over 4,000 unconventional gas wells have been drilled since 2004.

The analytical results were first compared to historical groundwater quality data from in or near the study area collected prior to shale gas development. The chemical composition of the samples collected prior to shale development was similar to that of the samples collected after shale development, and the range of concentrations for study samples fell within the historical range. There was no detectable signal from the shale gas development on the groundwater.

The chemistry of the six flowback water samples and the produced water samples were compared to the water well samples. The chemical analysis of the shallow groundwater samples indicated that they were distinct from the Fayetteville flowback and produced water geochemistry. Some samples had elevated bromide/chloride variations suggesting a communication with the Fayetteville Shale brine, but no spatial relationship was detected with these occurrences of elevated salinity. Similarly, dissolved methane gas was detected in approximately two-thirds of the drinking water wells, but only six of the wells had methane concentrations greater than 0.5 mg/L, and only one sample from one well had a concentration greater than the recommended action level of 10 mg/L put forth by the EPA. Dissolved methane concentrations were not correlated to shale gas wells. In addition, the isotopic analysis demonstrated that the methane was predominantly biogenic in origin, signifying that it was occurring naturally and was unrelated to hydraulic fracturing activity in the region. Only one sample had an isotopic ratio that approached the values reported for shale gas (Warner, et al. 2013).

The study concludes that the results of the sample comparison clearly show that there is no saline fluid contamination in drinking water wells located near shale gas sites. Moreover there is no apparent contamination with thermogenic methane in shallow drinking water near shale gas wells; most of the methane identified had an isotope composition that differs from the fingerprint of Fayetteville gas. The study did not find any signs of natural hydraulic connectivity between deep and shallow formations. Slightly saline groundwater samples were detected, but the spatial distribution of the samples had no correlation with the presence of shale gas wells; therefore, the study authors concluded that there was no relationship between the slightly elevated salinity of samples collected from domestic water wells and produced water from hydraulic fracturing. The study further concluded that the natural impermeability and lack of deformation of the formations prevents the flow of saline fluids.

Groundwater Quality Assessment from Domestic Water Wells in the Fayetteville Shale Gas Play Area in Central Arkansas (Nottmeier 2012)

This study conducted by the University of Arkansas' Department of Geosciences established a spatially-distributed set of baseline water quality data from shallow domestic wells across the Fayetteville Shale region. The purpose of collecting the groundwater data was also to support the hypothesis that groundwater quality in central Arkansas is directly related to the natural geology and lithology of the area and has nothing to do with oil and natural gas extraction activities.

The study area included six counties across the Fayetteville Shale in Arkansas. A total of 105 samples were collected from private drinking water wells across the region. All of the groundwater samples were analyzed and compared to USGS pre-existing groundwater quality parameters for central Arkansas. Two constituents (iron and manganese) exceeded the EPA's secondary MCLs in several samples, but not the primary MCL. The study concluded that the waters in the study area are highly reactive. The direct rock-water interaction and redox processes influence the reactivity, with three principal causes: 1) the recharge percolating through thin organic rick soils; 2) domestic water wells withdrawing from vertical fractures that interact with sandstones and shales; and 3) faults and low permeability systems that result in small isolated basins with short lateral flows. These processes are important in determining when naturally occurring metals are mobilized, anthropogenic contaminants are degraded or preserved, and what by-products might be generated within the aquifer system (Nottmeier 2012). The study determined the baseline; there was not an analysis of the effects of hydraulic fracturing on water resources.

BARNETT SHALE

The Barnett Shale is located in the Fort Worth Basin of north-central Texas. The Barnett Shale was the first in Texas and internationally where operators used horizontal wells. This shale play had a significant growth in the mid-2000s with more than 2,000 wells completed each year, but the play has seen a relative decrease in total number of wells completed in recent years as a result of reduced natural gas demand and price.

An Evaluation of Water Quality in Private Drinking Water Wells Near Natural Gas Extraction Sites in the Barnett Shale Formation, 2013 (Schug, et al. 2013)

The Barnett Shale has become one of the most heavily drilled formations in the last ten years. The overlying aquifers (Trinity and Woodbine) provide drinking water in rural areas where private wells are unregulated. In 2013, a group of researchers at the University of Texas at Arlington evaluated private drinking water quality in aquifers overlying the Barnett Shale in Northern Texas to determine if contamination from Barnett Shale natural gas extraction operations could be detected. The study did not focus specifically on the relationship between hydraulic fracturing and water resources.

Historical groundwater sampling data from the targeted aquifers for the concentrations of target compounds in the region were obtained to evaluate their occurrence before the expansion of natural gas activities. The historical dataset, spanning the period 1989 to 1999, consists of groundwater samples from 330 private drinking water wells in the three aquifers; the data period pre-dated the expansion of natural gas extraction in the area. Background data from the USGS shows that the drinking water quality in the overlying aquifers is generally good, with a few exceedances for arsenic, selenium, strontium, and barium.

Samples were subsequently collected from 100 private drinking water wells that draw from the Trinity and Woodbine aquifers. Selected water wells were located both within (91 samples) and outside (9 samples) of active natural gas extraction areas. “Active” sample locations were categorized as water wells with one or more gas wells within a five-kilometer radius, whereas “non-active” sample locations were water wells that do not have any active gas wells within 14 kilometers. In addition, five reference water wells were sampled from an adjacent aquifer, where there were no gas wells within 60 kilometers.

The effect of natural gas extraction on water quality was assessed by examining analytical results for VOCs and semi-VOCs, as well as arsenic, barium, selenium, and strontium. The potential contribution of gas extraction to contaminant concentrations was evaluated based on the geographic proximity of the samples to natural gas extraction activities.

The sample results showed slightly elevated TDS in both active natural gas extraction areas and non-active areas. Exceedances for the EPA’s MCL of 500 mg/L were detected in 50 out of 91 samples from the active extraction areas and seven of nine samples from the non-active areas. The mean TDS in active extraction areas was similar to historical levels (585 mg/L versus 670 mg/L).

Of the other constituents analyzed, arsenic, strontium, and barium are known to occur naturally in the aquifers overlying the Barnett Shale. Recent analytical results for arsenic were consistently greater than historical results, but this was observed in both active and non-active development locations. Selenium was detected in 10 of the 91 samples, exclusively in the active extraction areas and at concentrations greater than the historical averages; however, the authors of the study note that the sample size was too small to draw any conclusions about these selenium detections. Strontium and barium were also detected in all samples collected (active and non-active development areas), both at higher concentrations than historical levels.

Although the study did not identify a correlation between gas extraction in the Barnett and water wells, the study noted higher concentrations within the Barnett Shale region compared to outside the Barnett region. No cause was cited for the observation.

The study concluded that natural gas extraction activities do not result in a systematic contamination of groundwater. Samples that exceeded the MCLs and those with the highest concentrations were generally within 1 to 2 kilometers from the nearest gas wells, suggesting that gas well casing failures could be a cause. The cause could also be that localized groundwater withdrawals could play a role in the elevated constituent concentrations. For example, the lowering of the water table can lead to changes in pH that cause the leaching of metals ions from soils. Mechanical disturbances include pressure waves from drilling that could loosen particles from the casings of private wells, leading to increased turbidity. Also, in general, wells from the historical data set were on average 335 feet deeper than the wells sampled in the current study, which could explain the difference in concentrations found for some constituents.

Water Use for Shale-Gas Production in Texas, USA (Nicot, et al. 2012)

A 2012 study conducted by the Bureau of Economic Geology at the University of Texas, Austin estimated water use in Texas as a result of the increase in oil and gas development, as well as the development of technology that allows for the recycling of brackish water.

The study describes Texas shale plays in detail, including the Barnett, Eagle Ford, Haynesville, East Texas, Permian, Anadarko and Gulf Coast. The Barnett Shale has the longest history of shale gas development. The Eagle Ford has seen extensive development in the last three to four years. The study notes that hydraulic fracturing has expanded to the drier southern and western parts of the state and by necessity the industry has adapted to these new conditions. The industry has been decreasing its fresh water use despite showing a net increase in total water use.

The study includes information about recycling and reuse of brackish water gathered from operators. The amount of fresh water use varies considerably across the different shale plays based on local climate and conditions. In the Barnett Shale, for example, operators used predominantly fresh surface water (approximately 80 percent), whereas in the Eagle Ford Shale operators mostly used fresh groundwater (approximately 90 percent). In the Haynesville Shale, water is generally plentiful and no brackish water is reused, whereas in the Eagle Ford and Anadarko shale plays up to 30 percent of the water use is from recycled or brackish water. The amount of reuse is driven by the availability of freshwater, but also limited by the quantity of flowback and produced water from recently fractured wells. This varies significantly across plays. For example, wells in the Haynesville and Eagle Ford Shales produce less than 20 percent of the injected water.

The study also examines water quantity for hydraulic fracturing. Across the state, approximately 81,500 acre-feet (AF) of water were used for hydraulic fracturing. Water use is most extensive in the Eagle Ford and Barnett Shales (approximately 25,000 AF each). The majority of counties in Texas have some water use dedicated to hydraulic fracturing; in 2011, 126 counties dedicated at least 1 AF of water to hydraulic fracturing and 26 used more than 1,000 AF of water for hydraulic fracturing. The top ten counties use about half of all water used for hydraulic fracturing in the state.

The report projects water use to year 2060. The overall finding is that water used for hydraulic fracturing will generally plateau at approximately 125,000 AF per year sometime between 2020 and 2030 and then slowly decrease with time. However, it is hypothesized that the amount of fresh water consumed will remain relatively constant at approximately 70,000 AF, despite the increase in overall water use, and then slowly decline as the industry increases recycling of brackish water.

In general, projected oil and gas water use was dominated by hydraulic fracturing. However, oil and gas water use is a very small fraction of the total amount of water used in Texas every year. Hydraulic fracturing water accounted for 81,500 acre-feet in 2011, whereas the entire state of Texas used more than 15 million acre-feet of water; that is, hydraulic fracturing water use is 0.5 percent of the state's total.

DISH, Texas Exposure Investigation, Denton County (Texas DSHS 2010)

DISH is located in Denton County which overlies the Barnett Shale. The community was established in 2000; in 2005, energy companies began drilling wells for natural gas production. With five natural gas facilities currently in place, wells and heavy equipment now line a quarter mile of the town's south border (Hamilton 2012; Biello 2010).

As a result of complaints from residents about odors, the Texas Department of State Health Services conducted an exposure investigation of town residents. The purpose of the investigation was to compare the levels of volatile organic compounds (VOCs) in the blood from DISH residents to those measured in the general US population. Tap water samples were also collected because there were questions about groundwater contamination, which is the primary source of drinking water in DISH. This investigation involved sampling blood and urine from 28 city residents, as well as sampling tap water from 27 homes (Texas DSHS 2010).

Biological sample results were compared to data from the National Health and Nutrition Examination Survey. Although several different VOCs were detected in blood from some of the participants, the pattern of detection was consistent with exposures to consumer products (e.g., cigarette smoke and home maintenance products). Three of the compounds found in a few of the participants were disinfectant by-products associated with chlorinated drinking water systems. All of these participants obtained their drinking water from the same public drinking water system, which uses chlorine as a disinfectant to remove harmful infectious agents. Benzene and styrene were found above the reference value in four people, all of whom were smokers as verified by the presence of 2,5-dimethylfuran (a biomarker for smoking) in their blood and by their survey responses. Based on the sample results, Texas DSHS concluded that the level of VOCs in the blood of DISH residents was not different than people living in other areas of the U.S, and elevated levels were most likely based on the patterns of exposures, *The Pavillion gas field, located in the Wind River Range in Central Wyoming, has been the center of complaints related to groundwater contamination by hydraulic fracturing in the western US.*

- *In 2008, EPA received complaints that domestic water wells had foul odors and tastes. EPA initiated an investigation.*
- *In 2011, EPA released a draft report alleging that groundwater samples from deep test wells contained compounds found in hydraulic fracturing fluids. Numerous criticisms of the report were subsequently published.*
- *In 2012, EPA conducted additional sampling in conjunction with the USGS and State of Wyoming. USGS released results of the sampling indicated that none of the same contaminants detected in EPA's initial sampling were detected.*
- *In 2013, EPA announced that the agency has no plans to finalize the report or publish conclusions of its study. The agency deferred additional investigation to the State of Wyoming.*
- *The state of Wyoming published a work plan for additional investigation in June 2013. The state intends to conclude its investigation and publish a final report in September 2014.*

primarily due to smoking or exposure to disinfectant by-products in drinking water or home maintenance products. Other than these exposures, DSHS could not state with any certainty the exact nature of VOC exposures of DISH residents.

The water sample results were compared to the EPA MCLs. One sample contained trihalomethanes that exceeded the MCL. Trihalomethanes are by-products of disinfectants and form when chlorine is used in drinking water treatment; they are not related to natural gas production in the area. Other contaminants such as ethylbenzene, methyl tert-butyl ether, styrene, toluene, and xylene were detected in some of the water samples but the levels were well below their respective MCLs (Texas DSHS 2010).

NIOBRARA SHALE

The Niobrara Shale is a Cretaceous formation located in northeast Colorado, northwest Kansas, and southeast Wyoming. To date, most of the oil and gas development has focused on the Denver-Julesburg Basin (DJ Basin) and other sweet spots in the Wattenberg field of Weld County, Colorado and to a much lesser extent the Wind River Basin in Wyoming.

Pavillion Case Study Wind River Basin, Wyoming (Multiple Sources)

The Pavillion gas field, composed of a mixture of sandstones and shales, is located in the Wind River Basin in Central Wyoming. The upper portion of the formation serves as the primary drinking water source for residents of the area. Oil and gas operations began in the 1950s but increased dramatically between 1997 and 2006. Encana Oil and Gas owns the rights to the entire field and has not drilled any new wells since 2007.

In 2008, EPA received complaints from domestic water well owners that their water had foul odors and tastes, which they believed to be related to natural gas-related activities. In response, EPA initiated an investigation, collecting water samples from 35 domestic wells and two municipal wells between 2009 and 2011. EPA also installed two deep monitoring wells and collected two rounds of samples from each.

EPA released a draft report of its findings in December 2011, which theorized that the fluids seeped up from improperly sealed gas wells. Several months after EPA published its draft report, reviews by both critics and proponents of hydraulic fracturing provided additional expert opinion on the draft. The critical reviews contend that the data collection processes were faulty and no valid conclusions could be drawn from EPA's study. Notable criticisms of EPA's draft report are as follows:

- The pollution detected by EPA that was linked to hydraulic fracturing was found in deep water monitoring wells, not the shallower monitoring wells that are more comparable to the drinking water supply wells. The link between pollution in deep monitoring wells and shallow water wells is uncertain (DiGuilio et al 2011).
- Contamination in shallow monitoring wells was strongly linked to contamination from waste disposal pits at the surface, rather than due to hydraulic fracturing (DiGiulo et al 2011).
- EPA's monitoring wells were drilled directly into gas-bearing zones; approximately 200 to 275 meters below ground surface (656 to 902 feet); therefore, it is not unusual that elevated levels of methane, hydrocarbons, and benzene were detected (Petroleum Association of Wyoming 2011). Along the same lines, methane is naturally-occurring near the surface of the Wind River Formation and many residents recall the presence of methane in well water prior to the occurrence of energy production activities in Pavillion (EnCana Oil & Gas Inc. 2009).
- To the extent that drilling chemicals were detected in deep monitoring wells, EPA acknowledges the possibility of poor test wellbore design and integrity, resulting in vertical and lateral movement of contaminants to surrounding groundwater. The study stated that only two gas production wells in the Wind River Formation have surface casings that extend below the depth of domestic wells. Shallow surface casings in conjunction with little or no cement or sporadic bonding of production casings can facilitate upward gas and fluid migration. In addition, poorly sealed domestic water wells are a known concern in Pavillion and an improper seal can create a migration pathway for gas and fluids into domestic wells.

A report prepared for the Wyoming Water Development Commission notes that Pavillion's water is generally of poor quality and often has problems with taste and odor. However, the report also notes that the private well water consistently meets federal drinking water quality standards, though no baseline water quality is available to compare to the EPA testing results (Gore and Associates 2011).

While EPA's draft report identified potential links between hydraulic fracturing and contamination in the Pavillion water wells, the report remained a draft. At a hearing before the House Subcommittee on Energy and Environment, in February 2012, EPA Region 8 administrator, Jim Martin, stated the following in response to mischaracterizations of the draft report: "We make clear that the causal link [of water contamination] to hydraulic fracturing has not been demonstrated conclusively," adding that EPA's draft report "should not be assumed to apply to fracturing in other geologic settings" (Martin 2012).

In March 2012, EPA agreed that additional testing was needed in the Pavillion before a final report could be issued. EPA, in conjunction with the State of Wyoming, conducted further sampling of deep monitoring wells in the area. In a joint statement, EPA Administrator, Lisa Jackson, Wyoming Governor, Matt Mead, and the Northern Arapaho and Eastern Shoshone Tribes said:

"The EPA, the State of Wyoming, and the Tribes recognize that further sampling of the deep monitoring wells drilled for the Agency's groundwater study is important to clarify questions about the initial monitoring results" (EPA 2012c).

The USGS released reports from the sampling event in September 2012 at Pavillion. In USGS' subsequent testing they did not find the presence of several key chemical compounds that were initially reported in the EPA's deep monitoring well samples; and many other constituents were detected at significantly lower concentrations. The USGS data does not support a link between hydraulic fracturing and groundwater contamination. USGS identified several flaws in EPA's sampling procedures, including improper well construction, cross contamination of groundwater during monitoring, misrepresentation of monitoring well depth in relation to drinking water wells in the area. According to the USGS report, these deficiencies render the EPA's sampling data unreliable. While EPA made several mistakes in carrying out their groundwater investigation, the key findings of subsequent sampling by the USGS is that the compounds that the EPA identified as possibly linking hydraulic fracturing to groundwater contamination were not detected in USGS samples. The original purpose of EPA's investigation was to determine potential sources for inclement odors and tastes in drinking water wells. No connection to odor or taste has been determined and the constituents observed by the EPA were not detected in subsequent testing (API 2013).

In June 2013, EPA announced that the agency does not plan to finalize or seek peer review of its draft Pavillion groundwater report, nor does it plan to rely upon the conclusions put forth in the report. In a press release EPA notes that it stands behind its work and data, but recognizes the State of Wyoming's commitment to further investigation and efforts to provide clean water. The sampling data obtained throughout EPA's groundwater investigation will be considered in Wyoming's further investigation.

The Wyoming Oil and Gas Conservation Commission and Wyoming Department of Environmental Quality will conduct a comprehensive review of existing data and initiate additional science based studies (EPA 2013). As detailed in a Work Plan released by the state of Wyoming in June 2013, the state will sample fourteen domestic wells, prepare a report concerning the reclamation of historic production pits, which have been highlighted as a potential source of contamination, and study the integrity of all of the oil and gas wells within 1,320 feet of the fourteen domestic wells that will be included in the study (Wyoming Oil and Gas Conservation Commission 2013). The Wyoming Department of Environmental Quality will compile the three data sets (water from well tests, historic pits, and well integrity) to draw conclusions or determine if additional testing is needed. EPA will have the opportunity to provide input to the State of Wyoming and recommend third-party experts for the State's consideration. The State intends to conclude its investigation and release a final report by September 30, 2014 (EPA 2013).

Water Sources and Demand for Hydraulic Fracturing in Colorado, 2010 through 2015 (CDWR 2012)

The Colorado Division of Water Resources, the Water Conservation Board and the Colorado Oil and Gas Conservation Commission prepared a joint report highlighting the projected water demand for hydraulic fracturing in Colorado from 2010 through 2015. Water demand was estimated based on the number of wells constructed in 2010 and 2011 and existing reported data about water requirements for well construction and hydraulic fracturing (CDWR 2012).

In 2010, hydraulic fracturing represented 0.08 percent of total water used in the state (13,900 acre-feet); whereas 85 percent of the water was used for agriculture (13,981,100 acre-feet). Demand is expected to increase from approximately 13,900 acre-feet to approximately 18,700 acre-feet between 2010 and 2015. Based on this projection, the report estimates that in 2015, hydraulic fracturing will account for approximately 0.1 percent of the total water use in Colorado. The report provides no other conclusions regarding the significance of this amount of water to the overall Colorado water supply.

The report also identifies potential sources of water for hydraulic fracturing and provides a summary of the legal and administrative requirements for using each source. Potential sources include water transported from outside the state; irrigation water leased from a landowner; treated water from a wastewater treatment facility; diversions of surface water flows; groundwater; or recycled produced water. The report does not quantify any of these sources, nor does it provide conclusions about optimal water sources (CDWR 2012).

OHIO/DEVONIAN SHALE

The Ohio Shale (also called the Chattanooga Shale) is an upper Devonian formation of the Appalachian Basin. The main production area extends through Virginia, West Virginia, Kentucky, central Ohio and Lake Erie and into the panhandle of Pennsylvania. Utica and Marcellus Shales also span into Ohio, so that the geology associated with the Ohio Formation (Berea Sandstone) overlays both the Utica and Marcellus Shale in Central Eastern Ohio.

Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio (ODNR 2008)

In December 2007, the Ohio Department of Natural Resource, Division of Mineral Resources Management initiated an investigation into the cause of a house explosion. Responders quickly recognized that natural gas was entering homes through water wells; either unvented water well located in basements, abandoned and unplugged water wells in basements, or wells with indoor well pumps. The Ohio Valley Energy Systems Corp, which had recently completed a nearby oil and gas well, English No. 1, assumed responsibility for the natural gas contamination and resulting explosion (ODNR 2008).

The English No. 1 well was completed in a gas-bearing sandstone reservoir, the Clinton Sandstone, which overlies the shale deposits. Over 79,000 wells have been in the sandstone since 1897. The Clinton is generally 3,600 to 3,900 feet below surface in Bainbridge Township. This investigation does not address the relationship between hydraulic fracturing and water resources, nor does it directly relate to gas extraction from shale deposits. However, it is included in this Report because it is sometimes cited as a hydraulic fracturing related incident.

The Division of Mineral Resources Management investigated three potential factors that could have contributed to the gas invasion of the shallow aquifers: (1) inadequate cementing of the production casing around the well, (2) proceeding with hydraulic fracturing without addressing the casing deficiencies, and (3) the month-long period after hydraulic fracturing during which the annular space between the surface and the production casing was shut in, confining high-pressure gas in the restricted space and possibly allowing natural gas to migrate into natural fractures in the bedrock (ODNR 2008).

Although methane was detected in 22 domestic and one public water supply well, there is not a primary or secondary drinking water standard for methane because it is not toxic. The Division of Mineral Resources Management determined that the data indicates that groundwater was not contaminated or polluted by brine, crude oil, or hydraulic fracturing fluids. Furthermore, the data does not indicate that natural gas invasion of local aquifers altered inorganic water quality, or caused pollution salts or metals. The only exceedance of an Ohio EPA drinking water standard was not related to oilfield operations: iron and manganese concentrations exceeded secondary criteria, as is common for the aquifers in the area.

MONTEREY SHALE

The Monterey Shale is a rib-shaped formation that extends from northern California down to Los Angeles, and offshore to some of the outlying Channel Islands. The formation extends eastward from the coast throughout the entire San Joaquin Basin. A review of the website FracFocus.org shows that the majority of hydraulic fracturing in the state of California has occurred in Kern County (Inglewood Oil Field Hydraulic Fracturing Study; Tormey, et al. 2012)

To date, only one study has been conducted evaluating the potential environmental impacts of hydraulic fracturing in this formation. This study focused on a single oil field located in a highly developed area of Los Angeles County and was conducted as part of a settlement agreement between the oil field operator, the County of Los Angeles and a number of NGOs and citizen groups. The report was prepared on behalf of Plains Exploration and Production Company, and Los Angeles County. The study was peer-reviewed prior to publication.

The field on which the study focused operates under the jurisdiction of a County Specific Plan ordinance. Due to this regulatory oversight, 3 years of groundwater, air quality, vibration, noise, and ground movement data was collected prior to the start of hydraulic fracturing. The authors compared the pre-fracturing baseline data to data collected during hydraulic fracturing, and for up to one year following the high volume hydraulic fracture to evaluate any potential changes in baseline conditions. The study found no change in baseline conditions to groundwater quality, noise levels, vibration levels, seismicity, or air emissions.

The study also noted that the location of the field at the top of the Baldwin Hills affected the ability of the field to impact groundwater aquifers or drinking water sources. In particular, the Baldwin Hills are noted by the USGS and California Department of Water Resources as a “no flow” zone through which the local groundwater aquifer does not flow. All groundwater on the field is considered “perched” and disconnected from the aquifer. Further, the nearest public water supply groundwater well is located over one mile from the field and the majority of drinking water for the population surrounding the field is provided from Northern California and the Colorado River.

Other studies on the Monterey Formation are forthcoming in the next couple of years. The BLM will analyze current or reasonably foreseeable well completion and stimulation practices, including hydraulic fracturing and the use of horizontal drilling, in the Hollister Field Office. BLM is also initiating a peer-reviewed, third-party independent science assessment of the current state of industry practices for well completion and stimulation in California. The report is anticipated to be released in early 2014.

Senate Bill 4 (September 2013) includes a provision to conduct a study on hydraulic fracturing in California by 2015. The regulation does not provide details regarding who is to conduct the study, its scope, or whether it would be peer-reviewed.

The California Coastal Commission announced that it was investigating the prevalence of hydraulic fracturing in offshore oil wells. The scope of the study is unspecified, but is expected to examine the extent of hydraulic fracturing in state and federal waters offshore of California and the differences between onshore and offshore operations.

INTERNATIONAL

Midway Energy Ltd. Hydraulic Fracturing Incident: Interwellbore Communication January 13, 2012 ERCB Investigation Report (ERCB 2012)

An investigation was launched by the Energy Resources Conservation Board in Canada regarding hydraulic fracturing operations conducted by Midway Energy Ltd that resulted in the release of hydraulic fracturing fluid and formation fluid at the surface of a nearby producing oil well operated by Wild Stream Exploration. The release was noticed when a member of the public observed fluids being discharged from the Wild Stream wellhead. Responders were at the scene quickly and the site was largely cleaned up within 72 hours. Adjacent water wells were tested and results did not indicate contamination. Water and soil remediation and monitoring are ongoing.

Following the initial clean-up activities, a site investigation was launched and it was determined that the root cause of the incident was that the planned fracture stimulation was too large for the separation distance between the Wild Stream Well and another well operated by Midway Energy. The Wild Stream well is a vertical well and the Midway well is a horizontal well, but both wells target the same geological formation. The investigation found that Midway did not conduct the fracturing operation in compliance with its own internal procedure. The equipment at the Wild Stream well was not pressure rated to withstand pressures required for hydraulic fracturing, resulting in equipment failure with increased pressure from communication with hydraulically fractured well and a surface release of fracturing fluids and flowback (ERCB 2012).

The site investigation by the Energy Resources Conservation Board concluded that, if Midway had followed its own internal modeling and calculation protocols, and notified Wild Stream of its fracturing operations, then the incident could have been avoided or the impact reduced. In response to the incident, the Energy Resources Conservation Board released a list of expectations for well operators performing hydraulic fracturing, including fracture propagation modeling, identifying any wellbores in close proximity, notifying adjacent operators about hydraulic fracturing, working with other operators to ensure environmental controls are in place, and immediate notification in the event of unintended communication between wells (ERCB 2012).

This investigation report is the only study identified that links hydraulic fracturing to a potential effect to water quality. The conclusions, however, were that the hydraulic fracturing did not adversely affect water supplies. Rather, there was a surface spill from the adjacent well bore that was cleaned up.

Review of the Potential Public Health Impacts of Exposures to Chemical and Radioactive Pollutants as a Result of Shale Gas Development (PHE 2013)

To date, hydraulic fracturing has only occurred at one site in the UK. Nonetheless, there is public concern in the UK about the potential impacts of hydraulic fracturing on human health. These concerns are primarily in response to concerns expressed in the United States public media and internet sources. In 2012 Public Health England (PHE) established a working group to review the potential impacts of hydraulic fracturing on public health, focusing on the direct impacts of exposure to chemical and radiological pollutants as a result of shale gas extraction. The working group produced a Study that is a compilation of literature and data from other countries, including published and peer-reviewed scientific literature released before December 2012.

The authors of the study acknowledge that extrapolating data from other countries must be performed with caution because England has different underlying geologies, modes of operation and regulatory environments that could result in different risks. The study focuses on the evaluation of available literature related to air quality, radon, NORM, water and wastewater and hydraulic fracturing fluids.

The authors of the Study conclude the evidence from the literature and data analysis suggests that groundwater contamination is most likely caused by leakage through vertical boreholes rather than from the hydraulic fracturing process itself. The authors state that the literature review indicates that surface spills are a more likely potential pathway for contamination, as well as operational failures or a weak regulatory environment.

The authors of the study suggest a variety of mitigation measures based on experiences in the USA that can be applied in the UK to help reduce the risk of water contamination, including:

- Well integrity maintenance;
- Hydraulic fracturing fluid chemical disclosure;
- Monitoring of sensitive aquifers for indicator chemicals;
- Development of environmental quality standards where they do not already exist;
- Development of analytical detection methods for chemicals in fracking fluids and waste products; and
- Regulations on treatment facilities receiving produced water.

The authors conclude that based on the literature available that site operational controls, such as high quality well integrity and good environmental management of surface and below ground activities should adequately protect water resources. The authors acknowledge accidents may occur where the unintended consequences must be addressed appropriately. However, overall the authors conclude that there is a low risk to public health from direct releases of chemicals and radioactive material if shale gas extraction is operated and regulated properly (PHE 2013).

MULTI-REGIONAL STUDIES

Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs (EPA 2004)

In 2004, EPA conducted a study that analyzed the potential for contamination of underground sources of drinking water caused by hydraulic fracturing of coalbed methane (CBM) natural gas wells. Like shale gas, CBM is an unconventional source of natural gas. However, the coal seams typically occur at much shallower levels, less than 1,000 feet below ground surface. They are therefore closer to water supply aquifers than the deep shales. While not all CBM wells are completed by hydraulic fracturing, a portion of the wells do require this technique.

EPA conducted this study in response to a 1997 ruling by the Eleventh Circuit Court (*Leaf vs. EPA)* that hydraulic fracturing of CBM is a form of underground injection regulated under the Underground Injection Control (UIC) program, which triggered the EPA to assess the potential for hydraulic fracturing of coal bed methane to impair underground sources of drinking water. In addition, the study was performed in response to concerns by individuals who may be affected by CBM development. Congress used the study, in part, during development of the 2005 Energy Policy Act (EPAct). EPA released the results of the study in a report titled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reserves*.

EPA's 2004 study was two-fold. The first part was an extensive review of existing literature on the impacts of hydraulic fracturing on underground sources of drinking water. EPA reviewed more than 200 peer-reviewed publications and interviewed more than 50 employees in the natural gas industry, representatives of state and local agencies, and 40 concerned citizens and groups. The research focused on water quality incidents potentially associated with CBM hydraulic fracturing.

The second part of the study included a review of incidents of drinking water contamination thought to be associated with CBM hydraulic fracturing operations. EPA reviewed studies and investigations performed by state agencies in response to citizen complaints. Complaints investigated included: 1) drinking water with unpleasant taste and odor; 2) impacts to wildlife and vegetation; and 3) loss of water in wells and aquifers.

After reviewing the data and incidents, the EPA concluded that there were no conclusive links between water quality degradation in underground sources of drinking water and hydraulic fracturing in nearby CBM wells, even though thousands of CBM wells annually were being hydraulically fractured.

EPA did determine that in some instances, the coal beds being produced were located within drinking water sources; that is, the coal beds were shallow enough to be within fresh water aquifers. In these cases, fluids and chemicals (including diesel fuels) used for hydraulic fracturing were introduced directly into drinking water sources, as part of the design of the hydraulic fracturing job.

Diesel fuel was found to be the only compound of concern to water resources that was being used in hydraulic fracturing. As a result of this finding, EPA entered into a Memorandum of Agreement in 2003 with three major service companies (BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation), which cumulatively perform 95 percent of the United States' hydraulic fracturing projects, to eliminate diesel fuel from the fracturing fluids... In the 2005 Energy Policy Act, Congress only required an underground injection control (UIC) permit under the Safe Drinking Water Act for hydraulic fracturing that uses any amount of diesel fuel.

The 2004 EPA study concluded that hydraulic fracturing fluids in CBM wells do not threaten underground sources of drinking water. Based on this conclusion, EPA recommended against a Phase II study (EPA 2004).

Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, (DiGiulio et al 2011, EPA 2012a)

Continued technological advancements in the field of hydraulic fracturing and the application of the technology to tight sand and shale reservoirs has made the practice more prevalent since EPA released its 2004 CBM report. Citing increasing public and media interest and concern about the impact of hydraulic fracturing on drinking water resources, in fiscal year 2010 the US Congress' Appropriation Conference Committee directed EPA to conduct research to study the relationship between hydraulic fracturing and drinking water resources. The purpose of the study is to answer two overarching questions: 1) can hydraulic fracturing impact drinking water resources; and, if so, 2) what conditions intensify these impacts (DiGiulio et al 2011).

In February 2011, EPA published a *Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources (Study Plan)*, with the objective of identifying the factors that have the potential to affect sources of drinking water. The study began with input from an External Science Advisory Board, which recommended that the study include:

- Use of lifecycle framework to identify important research questions;
- Direct initial research to sources and pathways of potential impacts of hydraulic fracturing on water resources, especially drinking water;
- Analysis of five to ten in-depth case studies at locations representing the full range of regional variability across the nation; and,
- Stakeholder engagement throughout the research process.

As the study will focus almost exclusively on water resources, EPA examined how water was used during each stage of hydraulic fracturing operations and developed related fundamental research questions (Table A-4).

Table A-4 - Examination of Water Use During Hydraulic Fracturing

Issue Area	Questions
Water acquisition	How might large volume water withdrawals from ground and surface water resources impact drinking water resources?
Chemical mixing/site management	What are the possible impacts of releases of hydraulic fracturing fluids on drinking water resources?
Well construction and injection of fracturing fluids	What are the possible impacts from the injection and fracturing process on drinking water resources?
Flowback and produced water generation	What are the possible impacts of releases of flowback and produced water on drinking water resources?
Water treatment and waste disposal	What are the possible impacts of inadequate treatment or hydraulic fracturing wastewater on drinking water resources?

Source: DiGiulio et al 2011

To answer these questions, the EPA study work plan proposed to use a combination of:

- Retrospective case studies focusing on studying potential impacts where hydraulic fracturing has already occurred;
- Prospective case studies focusing on sites where hydraulic fracturing will occur after research has begun so that site conditions can utilize monitoring before, during, and after hydraulic fracturing operations; and
- General scenario evaluations which will explore hypothetical situations related to hydraulic fracturing.

In each case, the research approach includes literature reviews, gathering and analyzing existing data, analytical methods, modeling/scenario evaluations, toxicity assessments, and stakeholder-suggested case studies. In addition, EPA will summarize the available data on chemical, physical, and toxicological properties of hydraulic fracturing fluid additives to better understand their effects and identify data gaps. The chemicals will also be compared to naturally occurring substances.

As of the release of the 2011 Final Study Plan, EPA had conducted an initial literature review, requested and received information from industry on chemicals and practices used in hydraulic fracturing, discussed initial plans for case studies with landowners and industry representatives, and conducted baseline sampling for retrospective case studies (DiGiulio et al 2011).

In December 2012, EPA released a Progress Report describing the steps taken since the release of the Final Work Plan in 2011. The progress report listed a set of 18 research projects EPA had initiated help answer the research questions described in Table 2 above. The research projects, which are currently underway, are further divided according to five types of research activities. A summary of each research activity and the status as of the writing of the Progress Report is provided in Table A-5.

Table A-5 -Summary of Research Activities and Progress

Research Activity	Summary of Activity and Progress
Analysis of Existing Data	Data from seven sources have been compiled and reviewed including: Data from nine hydraulic fracturing service providers Well files from operators Chemical disclosure records Spill Reports
Scenario Evaluations	Computer models are being used to assess: The possibility of subsurface gas and fluid migration from deep shale formations to overlying aquifers Concentrations of chemicals in water supplies downstream from treatment facilities that discharge hydraulic fracturing waste water Impacts on water availability from withdrawing large volumes of water in basins with varying climates
Laboratory Studies	A variety of lab studies are underway focusing on: Efficacy of common wastewater treatment on chemicals in hydraulic fracturing waste water and impacts of inadequate treatment of hydraulic fracturing wastewater on drinking water resources Determining source of high Br and Cl concentrations using samples of surface water, raw hydraulic fracturing wastewater, and treated effluent Develop analytical methods for selected chemicals found in hydraulic fracturing fluids or wastewater
Toxicity Assessment	EPA has evaluated data to identify chemicals reportedly used in hydraulic fracturing fluids from 2005 to 2011 and chemicals found in flowback and produced water. Chemical, physical, and toxicological properties have been compiled for chemicals with known chemical structures.
Case Studies	Two rounds of sampling at all five retrospective case study locations have been completed. A third round of sampling was to occur in 2013. Prospective cases studies are currently under development in collaboration with industry partners.

Source: EPA 2012a

The Progress Report provides a detailed summary of each research project that is underway, including the research approach, the status of progress, preliminary data, and planned next steps. The Progress Report notes that all findings presented in the report are preliminary and cannot be used to draw conclusions about the impacts to drinking water from hydraulic fracturing. There is also a summary how each of the research questions outlined in the Study Plan is being assessed by the ongoing research projects. Results from individual research projects will undergo peer review prior to publication as either articles in scientific journals or as EPA reports. EPA synthesized results from the published reports and provided a draft "Assessment Report" in June of 2015, which was peer-reviewed and released for public comment. The draft Assessment Report identified and assessed the potential for hydraulic fracturing activities to impact the quality of drinking water resources and identify factors that may affect the severity and frequency of potential impacts. A final report is expected by the end of 2016.

Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters (Entrekin, et al. 2011)

This study explores the relationship between hydraulic fracturing and surface water bodies in the Marcellus and Fayetteville shale play areas. The study examines the proximity of active gas wells to water resources using state well-location data. The data suggests that, on average, wells are situated within 300 meters of streams, but occasionally wells are sited within 100 meters of stream channels. This finding is generally consistent across both regions. In both formations the distance between active wells and the nearest public surface water drinking supplies is approximately 15 kilometers, whereas the distance to the nearest public water wells ranges from 10 kilometers and 70 kilometers in the Marcellus Shale and is approximately 125 kilometers in the Fayetteville Shale.

The study examined natural drainage networks and determined that over 80 percent of the wells are within 300 meters of the modeled drainage areas, and as gas production continues to increase, they suggest that the proximity of wells to stream channels is also likely to continue to increase. According to the study, this may result in a larger risk of stream flow reduction from pumping, sedimentation resulting from infrastructure development, or contamination from leaks and spills.

The study notes that, even with the rapid expansion of natural gas development, violations have been aggressively identified and addressed in Pennsylvania – 1,400 drilling violations were issued between January 2008 and October 2010. Nearly half of these were related to surface water contamination, including direct discharge of pollutants, inadequate erosion control, or mishandling of wastes. None of these are directly related to hydraulic fracturing.

In contrast, in the Fayetteville Shale, there were only 15 surface water-related violations in 2010, over half of which dealt with violations of discharge permits.

The study identified three primary threats to surface water associated with shale gas development; sediments from well pads and roads, water withdrawals, and release of waste waters. With regard to sediments, the researchers identified seven streams in the Fayetteville Shale to test whether stream turbidity increased with well density. Turbidity measurements revealed that turbidity was positively correlated to well density and no other land cover measurements. However, there was a strong negative correlation between turbidity and drainage area and percent pasture cover in the area, suggesting a need for additional testing.

With regard to water withdrawals, the study notes that rapid and concentrated extraction of water could create regional shortages that could result in alterations to flow regime and degradation of habitats. Similarly, with regard to wastewater discharges the study simply notes that water treatment and disposal options are limited, especially given the increasing quantities of waste water generated.

The study concludes by presenting a suite of recommended studies to further examine the impacts of natural gas development on surface water and ecological communities, such as studies to examine the how sedimentation may alter species interaction, the toxicity of contaminant mixtures, impacts to community structures and other ecosystem based issues (Entrekin, et al. 2011).

Hydraulic Fracturing and Water Stress: Growing Competitive Pressures for Water (Freyman and Salmon 2013)

Ceres, a nonprofit organization focusing on sustainability challenges, examined the water used in hydraulic fracturing and the extent to which hydraulic fracturing takes place in regions that are already highly water-stressed. The study collected data on shale oil and gas operations from 2011 and 2012 (Fracfocus.org) and compared that to water stress indicator maps developed by the World Resources Institute. The World Resources Institute water stress maps define high water stress areas as regions where over 80 percent of the available water is already being withdrawn for municipal, industrial, and agricultural uses.

The study found that nearly half of all oil and gas extraction wells developed in the US in 2011 and 2012 were located in water basins with high or extremely high water stress, and over 75 percent of the wells were developed in areas with medium or greater water stress. Texas, Pennsylvania and Arkansas were the states with the highest net water use for hydraulic fracturing in 2011 and 2012. In Pennsylvania, which has plentiful water resources, 98 percent of the wells were completed in regions with medium water stress or less. Similarly, the study noted that wells completed in Arkansas were not in areas with high water stress. However, the study notes that wells in Texas account for almost half of all of the wells hydraulically fractured in the US in 2011 and 2012, and almost half of these wells are located in regions with high to extremely high water stress. Similarly, 97 percent of the wells in Colorado have been developed in regions with high to extremely high water stress.

The study notes that while water used for hydraulic fracturing is generally much less than one percent of a state's total water use, at the local level this percentage can increase (Freyman and Salmon 2013).. However, it should be noted that the study links the data set of well locations and water volumes being injected with data about water quantity indicators and draws conclusions but does not provide further data about where the water for these wells is drawn from. By drawing conclusions about the relationship between fracturing and water stress from well location and water stress data without the associated water source data, the study assumes that the water being used for hydraulic fracturing is drawn from the same area that the well is located. However, in the case of the oil field in Southern California, the primary sources of water for all oil field operations are the Colorado River and the San Joaquin Delta (Tormey, et al. 2012).

The study suggests methods to mitigate water stress, such as incentivizing recycling of waste water and performing hydraulic fracturing with non-freshwater resources. The study notes that in the Marcellus Shale recycling rates have reached 40 percent, and that in Texas, 20 percent of the water used for fracturing is saline. However, the study concludes that more attention should be paid to the best way to manage the increasing demand that hydraulic fracturing is putting on US water resources (Freyman and Salmon 2013).

Hydraulic Fracturing and Water Stress: Water Demand Numbers (Freyman 2014)

This study, which accompanies the 2013 Ceres report summarized above, analyzes the sources of water used for hydraulic fracturing operations around the United States and Canada and provides recommendations for reducing risks to operators related to identifying water sources. The study separates the risks into three primary categories – physical, regulatory, and reputational. Physical risks are those associated with water availability and quality. Regulatory risks include how water resources are regulated and allocated, and reputational risks are related to how communities view a company's impact on these resources. The study notes that all factors are important considerations for operators and can affect the industry's social license to operate. The research presented in the study is based on publicly available well data from fracfocus.org, reported between January 2011 and May, 2013, as well as water stress indicator maps developed by the World Resources Institute.

The study does not specifically address the relationship between hydraulic fracturing and water resources, but considers the broader context of shale gas development, which includes activities beyond the well pad and beyond the specific activity of completing a well with hydraulic fracturing. The study notes that based on available data, shale gas development uses a similar amount of water as other energy sources per unit of energy produced.

The study provides a variety of case studies from six U.S. shale plays; the Eagle Ford, Permian, Monterey, Bakken, Marcellus, Niobrara as well as two Canadian plays in Alberta and British Columbia. The selected case study regions are in varying stages of shale development, are geographically diverse, and have a variety of water related issues. Each case study provides a summary of water use trends in the region, a description of potential water source issues, a discussion of high water use counties within the play, the largest operators in the play, and recommendations for stakeholder engagement. The case studies highlight the wide range between of water related variability between plays. For example, 98% of wells in the Monterey formation are in areas with high water stress, whereas only 2% are located in high stress regions in the Marcellus. In contrast, the average water use per well in the Monterey shale is 134,000 gallons whereas it is 4.4 million gallons in the Marcellus.

Similar to Freyman and Salmon 2013, this study notes that despite the variability, in many instances hydraulic fracturing occurs in areas with high water stress and points to the intense and localized nature of shale development and the associated strain on local water supplies. This study suggests that there is not currently a robust data set about water volume used in each shale play, the source of water for shale gas operations, how much water is used, the quality of water used (brackish or freshwater), the timing of water withdrawals, or projected future water needs. As such, the study provides a variety of policy recommendations, such as detailed operator water use reporting requirements, similar to those in Pennsylvania, which already requires disclosure of freshwater and recycled water use for hydraulic fracturing. Moreover, the Susquehanna River Basin Commission in Pennsylvania performed a cradle-to-grave water lifecycle analysis for all consumptive uses of water in non-conventional oil and gas. The analysis showed that one Marcellus well requires about 5.4 million gallons of water, of which 65% is used for direct water consumption at the well, and 35% is used indirectly at other steps in the supply chain. Additional regulatory recommendations provided by the study authors include cataloguing all water use, requiring water source and recycling disclosure, wastewater management plans for operators, reducing underground injection, reducing aquifer exemptions, using incentives or mandates to increase recycling, and separating water sourcing oversight from the oil and gas department to ensure oversight is independent. The study concludes that all of these steps would help operators reduce risks associated with obtaining water for hydraulic fracturing operations. The study also suggests strengthening stakeholder involvement by engaging with local communities to help bolster the social license to operate (Freyman 2014).

Constraints on Upward Migration of Hydraulic Fracture Fluid and Brine (Flewelling and Sharma 2013)

A variety of studies have discussed the possible relationship between hydraulic fracturing and the upward migration of fracturing fluids and brine through bedrock, either through preexisting hydraulic connectivity or connectivity caused by the fracturing. However, this particular study notes that these suggestions of high upward migration flow rates over short time intervals contradict a large body of literature on hydrology and sedimentary basins. The study discusses the physical constraints on upward fluid migration from shales, including physical setting of the shales or that factors that control fluid migration and concludes that rapid upward migration caused by hydraulic fracturing does not seem to be physically plausible. The study discusses a number of reasons why this theory is not plausible. First, the study notes that the potential for upward migration is controlled by the relationship between two primary factors: 1) permeability and 2) head gradient. Permeability is controlled by grain size distribution and a variety of other factors, including stress, compaction, saturation and cementation, all of which are high at depth, reducing the potential for migration. In addition, the study notes that an upward head gradient is needed for upward flow, which is derived from topography or overpressure. Over-pressurized settings are most often associated with low permeability rock, making the likelihood of upward migration very small.

As discussed in the study, hydraulic fracturing increases permeability at depth, but affects a much smaller thickness than that of the overlying bedrock. Moreover, there is a large volume of monitoring data on fracturing height that indicates that fractures have remained well below the depth of a potable water aquifer. Similarly, the short duration and localized pressure caused by hydraulic fracturing, followed by the depressurization initiated by bringing a well onto production renders pressure propagation and the displacement of natural brines highly unlikely; after a hydraulic fracturing simulation the hydrocarbon extraction process draws fluid *toward* the target formation; the opposite direction than the upward migration proposed by various authors.

The authors conclude that natural upward migration does occur, driven by head gradients of over-pressuring, but flow rates are low and timescales are long. As such, the authors suggest that the rapid migration scenarios proposed by, for example, Myers 2012 and Warner et al. 2012 are not plausible (Flewelling and Sharma 2013).