Industry Practices and Trends Protecting Water Resources during Hydraulic Fracturing: Information for U.S. EPA's Draft Assessment

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Fact Sheet: Industry Practices and Trends Protecting Water Resources During Hydraulic Fracturing

The U.S. Environmental Protection Agency's Draft Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources was issued in July 2015, and comments were provided by the Science Advisory Board (SAB) in August 2016. The EPA Draft Assessment concluded that there was no evidence that hydraulic fracturing has led to widespread, systemic impacts on drinking water resources in the United States. The SAB makes recurring comments about the lack of information related to existing industry standards, best management practices, trends within the oil and natural gas industry, and state and federal regulations pertaining to hydraulic fracturing's potential effects on water resources.

The American Petroleum Institute, as the leader in developing operating standards for the oil and natural gas industry since its founding in 1924, provides this report summarizing the extensive protections provided by industry practices and regulatory programs to assist EPA in developing the final Assessment. The information is organized in parallel to the EPA Draft Assessment and the SAB comments, focusing on the steps of the hydraulic fracturing water cycle.

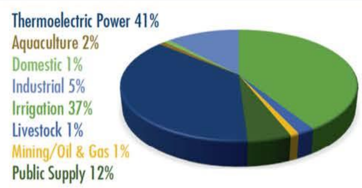
Chemical Mixing

The EPA Draft Assessment focuses on the potential for and causes of spills of chemicals used in hydraulic fracturing. The SAB is concerned that much of the data came from only Pennsylvania and Colorado, and that additional information about the standard practices that are applied to chemical mixing that reduce spill potential be provided. In fact, the EPA Draft Assessment relies on a much larger data set, including the ten states with the greatest rates of hydraulic fracturing between 2009 and 2010 for everything except spill frequency. The Pennsylvania and Colorado state databases include spill frequency related to hydraulic fracturing. These two states have the second and third highest amount of hydraulic fracturing in the US.

This report summarizes the large array of industry standards and best management practices to minimize spills and thereby protect water resources. The vast majority of onshore spills do not reach water resources. Spill protection is an area of steady improvement, and there are industry trends to utilize "greener" chemicals, keep more robust data on chemical use and spills, and report this information to the public.

Water Acquisition

The EPA Draft Assessment relies on data at state and county scales, while the SAB seeks information at even more local scales. At any specific place, based on specific local circumstances, it is possible that there may be an adverse effect based on acquiring water for hydraulic fracturing. The data at national, state, and local scales indicate that water acquisition does not lead to any widespread or systematic effects to water quantity. In areas where water is scarce, or where water acquisition has the potential for local effects, there is typically a regulatory program in place to minimize the likelihood of such effects. These programs balance the needs of all water users, including ecosystem services, to adjudicate water rights. Water use is an area where industry has shown continuous improvement. For example, technological innovation has enabled increased use of produced and brackish water for hydraulic fracturing.



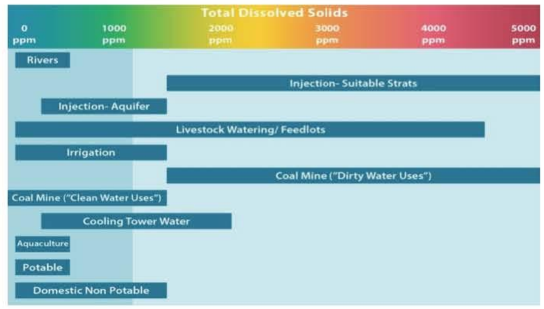
At state and national level water consumed for oil and gas industry is less than 1" of total water use. Local regulatory programs account for all water users when allocating water rights

Well Injection

EPA Draft Assessment identified injected fluid migration to shallower depths via compromised well integrity or subsurface geology to be of potential risk to water resources. The SAB requested additional information about industry standards and best management practices for well integrity. This report includes summaries of the extensive protections to ensure well integrity and prevent or minimize potential environmental impacts, including practices for well design, drilling, casing, cementing, well spacing and abandonment, as well as testing and monitoring. This report also explains how hydraulic fracturing occurs for one hour per stage, thus the well is only subject to pressure for a short duration. Once the well is brought on to production, the well is subjected to a relative vacuum force to extract fluids, the opposite type of pressure as hydraulic fracturing, and one that inherently protects water resources.

Flowback and Produced Water Management

The EPA Draft Assessment focuses on spills of flowback and produced water, and the SAB requests information on advancements in produced water management over the last several years. This report provides additional information on industry practices and trends with respect to improvements in flowback and produced water storage management and disposal and provides an extensive discussion of trends in produced water management, treatment, and beneficial reuse. This is an active area of research by industry, service providers, and regulatory agencies.

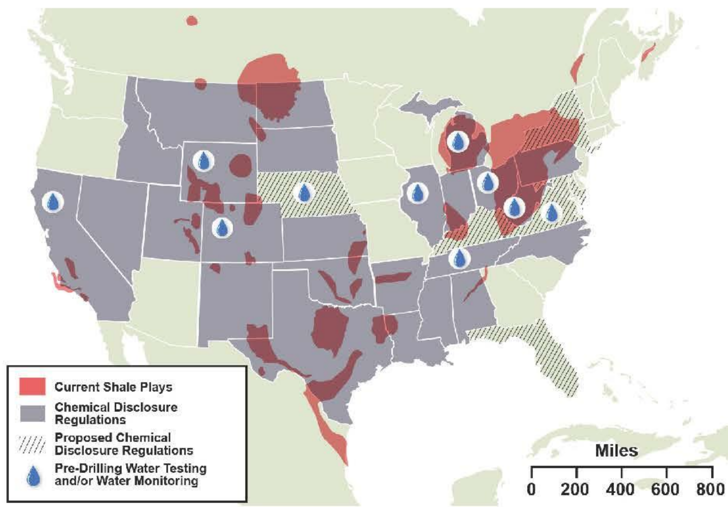


Site-Specific Produced Water Beneficial Reuse Compatibility Chart

Nationally and internationally, technologies are improving to increase options for the beneficial use of produced water by industry and other users.

Regulatory Framework

The SAB suggests that the EPA's Assessment would be strengthened by including a discussion of state regulatory standards that address the risk of water quality impacts associated with hydraulic fracturing. This report describes that states with hydraulic fracturing have expanded existing regulatory programs to address the process. Since hydraulic fracturing depends on local conditions, State regulatory frameworks are best positioned to address potential effects of hydraulic fracturing on water resources.



State Chemical Disclosure and Water Quality Monitoring Requirements

Overall, the report demonstrates that there is an extensive array of industry practices, industry trends, and regulatory programs that protect water resources from potential impacts of hydraulic fracturing at every step of the hydraulic fracturing water cycle, from initial water acquisition, through well injection to produced water disposal. In addition, water management is taking an increasingly prominent place in corporate governance of oil and gas companies to reduce risks and improve sustainability, ensuring that improvement will be an ongoing process. The prevalence of these practices nationwide is the likely reason why the draft EPA Draft Assessment found no widespread, systemic impacts on drinking water resources from hydraulic fracturing. The report documents these practices and protections, as well as the trends in innovation and improvement by industry. State regulatory frameworks are best positioned to address the local water resources in areas where hydraulic fracturing is conducted

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Acronyms

ANPR	Advance Notice of Proposed Rulemaking
ANSI	American National Standards Institute
API	American Petroleum Institute
bbl	barrel
BLM	Bureau of Land Management
BMP	best management practices
CCST	California Council on Science and Technology
CGE	carrier gas extraction
COGCC	Colorado Oil and Gas Conservation Commission
CSSD	Center for Sustainable Shale Development
CWTs	centralized waste treatment facilities
DOT	Federal Department of Transportation
EPA	U.S. Environmental Protection Agency
FO	Forward Osmosis
FTE	Freeze-Thaw/Evaporation
GWPC	Groundwater Protection Council
HF	hydraulic fracturing
IOGCC	Interstate Oil and Gas Compact Commission
ISO	Organization for Standardization
mg/L	milligram per liter
SDS	Safety and Data Sheet (formerly known as Material Safety Data Sheet or MSDS)
NPDES	National Polluant Discharge Elimination System
OPD	Oil Pollution Act
PADEP	Pennsylvania Department of Environmental Protection
POTWs	publicly owned treatment works
RO	reverse osmosis
SAB	Science Advisory Board
SCADA	Supervisory Control and Data Acquisition
SPCC	Spill Prevention, Control, and Countermeasure
SRBC	Susquehanna River Basin Commission
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
TDS	total dissolved solids
TSCA	Toxic Substances Control Act
TSS	total suspended solids
UIC	Underground Injection Control
USBR	United States Bureau of Reclamation
USGS	United States Geological Survey
UV	ultraviolet
WDR	waste discharge requirement

SECTION 1

Introduction

In June 2015 the U.S. Environmental Protection Agency (EPA) released a draft report for a study entitled *Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resource* (EPA Draft Assessment) (EPA 2015a). The purpose of the EPA Draft Assessment is to synthesize available scientific literature and data in order to assess the potential for hydraulic fracturing for oil and natural gas development to impact the quality or quantity of drinking water resources. The EPA Draft Assessment also identified factors affecting the frequency or severity of potential impacts.

The EPA Draft Assessment was conducted in response to a request from Congress in 2010 to evaluate the relationship between hydraulic fracturing and water resources. In March 2010, EPA announced that it would conduct a comprehensive, state-of-the-science, study investigating the potential impacts of hydraulic fracturing on our nation's water resources. The EPA issued a study plan in 2011 and released a preliminary progress report in December 2012. 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 EPA Draft Assessment concludes that the number of known instances of impact to drinking water was small in comparison to the number of wells hydraulically fractured, 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 Advisory Panel initiated its peer review of the Draft Assessment in late August and held several public meetings and public teleconferences from October 2015 through March 2016 culminating in their draft Quality Review Report delivered to the full SAB for its consideration. The SAB completed its review, and on August 11, 2016 transmitted their final review (known hereafter as the SAB comments) to the EPA. A recurring SAB comment is the lack of information related to existing industry standards, best management practices, trends within the oil and natural gas industry, and state and federal regulations, which address some of the concerns noted by the EPA and the SAB. The EPA Draft Assessment acknowledges in several locations that it did not systematically include state and federal regulations, and evolving industry practices and standards in the report. In addition, the SAB accurately remarks that "the hydraulic fracturing industry is rapidly evolving, with changes in the processes being employed" and that the EPA final Assessment should highlight these changes, while noting that "the Assessment necessarily was developed with the data available at a point in time."

Catalyst Environmental Solutions, on behalf of American Petroleum Institute (API) prepared this report to provide information regarding industry practices and trends, and regulatory programs to assist in responding to the SAB's comments. Since 1924, API has been the leader in developing operating standards for the oil and natural gas industry. Accredited by the American National Standards Institute (ANSI), API has issued over 600 consensus standards governing all segments of the oil and natural gas industry. These include standards, guidelines, and recommended practices regarding hydraulic fracturing, effective water management, spill prevention and environmental protection. Many API standards and practices are incorporated into both federal and state oil and natural gas regulations, including EPA regulations. These guidance documents are frequently updated to reflect operational improvements and quality assurance. As part of API's on-going effort toward continual improvement of oil and natural gas operations, in May of 2011, API completed a series of industry guidance documents specific to hydraulic fracturing:

- HF1, Hydraulic Fracturing Operations—Well Construction and Integrity;
- HF2, Water Management Associated with Hydraulic Fracturing Guidance; and
- HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing.

These documents were used as the basis to develop industry standards for hydraulic fracturing in accordance with API's ANSI approved "Procedures for Standards Development" which allows for submittal as ANSI standards. As a result, the following ANSI certified, API Recommended Practices for industry standards emerged:

- RP 100-Part 1 – Well Integrity and Fracture Containment; and
- RP 100-Part 2 – Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing.

In addition, during the consensus process, a new document, focusing on community engagement, was developed. ANSI/API Bulletin 100 - Part 3 – Community Engagement Guidelines (released in July of 2014) now serves as a gold standard for good neighbor policies that address community concerns, enhance the long-term benefits of local development, and ensure a two-way conversation regarding mutual goals for community growth.

Based in part on this extensive knowledge base provided in the full suite of API guidance documents, including RP 100-1, -2, and -3 that focus specifically on hydraulic fracturing, this report provides a summary of the protections provided by industry and by state regulations that were not fully addressed in the EPA Draft Assessment, and that the SAB has requested in their review. As discussed in detailed in this report, each state where hydraulic fracturing is conducted has comprehensive regulations addressing oil and natural gas production. This report identifies unique state actions and regulations specific to hydraulic fracturing and the protection of water resources, as well as industry practices and company initiatives related to water resources. Both the EPA Draft Assessment and the Panel peer-review are *draft* documents subject to modification. The intent of this report is to provide additional information for consideration in developing the Final EPA Assessment.

This report is organized to parallel the EPA Draft Assessment and the SAB comments. Key findings and potential mechanisms for impacts to water resources are organized based on each step of the hydraulic fracturing water cycle:

- Water Acquisition
- Chemical Mixing
- Well Injection[1]

[1] EPA defines "well injection" as *the process of pumping hydraulic fracturing fluid down the well at high pressures to create cracks in rock formations that allow oil and natural gas to flow from small pores to the production well*. Industry nomenclature for the well stimulation technique of hydraulic fracturing is not referred to as "injection" so as not to confuse it with the

- Flowback and Produced Water
- Wastewater Treatment and Waste Disposal

For each of these steps, this report provides an overview of the key conclusions presented in the draft EPA Draft Assessment and the draft SAB comments. This report then provides the additional relevant information available from state and federal regulatory programs, and evolving industry standards and operating practices, and industry trends. These issue-specific Sections are provided following the brief description of unconventional oil and natural gas development in Section 2.

"injection of wastewater" into a federally permitted underground injection control (UIC) well. However, for purposes of this report, we do use EPA's terminology.

Unconventional Oil and Natural Gas Development

Within the last decade, the combination of horizontal wells installed with GPS-mounted drill heads to precisely guide the drill bit through relatively thin reservoir formations, and high-volume hydraulic fracturing completions has allowed the production of natural gas and oil from deep shale and tight sands deposits. Previously, the oil and natural gas-bearing shales were thought of as the source rocks of petroleum, from which oil and natural gas could not be economically produced directly. With the advent of new technology, companies now have the ability to precisely drill a horizontal well to be entirely within a relatively thin shale and tight sand bed using GPS technology, and then to precisely fracture that shale and prop open the fractures with sand and/or ceramic proppants to produce hydrocarbons from formations that previously were not economical.

The ability to capture hydrocarbon resources from zones that previously could not be produced is one form of development of "unconventional sources of oil and gas". As applied to shale gas, this technique has completely changed the estimate of economic natural gas reserves. U.S. natural gas reserves had previously been thought to be in decline. To supply the nation's energy needs, numerous plans to import natural gas from overseas as liquefied natural gas (LNG) were proposed between 2000 and 2005. Since then, as a result of the added oil and natural gas resources from shale source rocks, the U.S. now produces the most natural gas and the most oil and natural gas combined compared to any other county. This expanded production has resulted in significant benefits to the U.S. and its economy. The availability of abundant natural gas has displaced the use of coal in electrical generating stations, leading to a substantial reduction in U.S. greenhouse gas emissions that has put the nation far along the path towards meeting the goals of the proposed federal Climate Action Plan. The low price of natural gas has provided reduced raw material and energy costs for the chemical and manufacturing industries, supporting growth in employment in these sectors. The geopolitical and geostrategic advantages to energy independence that have made it a national goal since the 1973 oil embargo and the 1979 oil crisis following the Iranian revolution, are beginning to be felt.

Hydraulic fracturing is not part of the drilling process, but is a completion technique applied after the well is drilled, cased and cemented, and perforated, and the drilling rig has moved to another site. It is a well completion technology that results in the creation of fractures in rocks that allows oil and natural gas in the source rock to move more freely through the rock into the well. Hydraulic fracturing is a well stimulation process used to maximize the extraction of underground resources.

Hydraulic fracturing for stimulation of oil and natural gas wells was first tested in the United States in 1947. It was first used commercially in 1949, and was rapidly adopted because of increased well performance and increased yields of oil and natural gas from relatively impermeable rock units. It is now used worldwide in tens of thousands of oil and natural gas wells annually.

In general, the process of hydraulic fracturing consists of injecting water, sand, and additives into the well over a short period of time (typically less than an hour per stage) at pressures sufficient to fracture the rocks of a formation. Water and small granular solids such as sands and ceramic beads, called proppants, make up approximately 99 percent or more of the fluid used in a typical hydraulic fracturing operation. This is consistent for both conventional and high-volume hydraulic fracturing. The flow of water acts as a delivery mechanism for the sand, which enters the newly-created fractures and props them open. If proppant does not enter a new fracture, then the pressure of the overlying rocks forces the fracture closed. These proppant-filled fractures allow oil and natural gas to be produced from reservoir formations that are otherwise too tight to allow flow.

The additives in the water help the sand to be carried farther into the fracture network. Such additives used to increase the viscosity of the water include gelling materials and/or foaming agents. Other liquid and solid additives that may be incorporated in the fracturing fluid are surfactants, a soap-like product designed to enhance water recovery, friction reducers, biocides to prevent microorganism growth, oxygen scavengers and other stabilizers to prevent corrosion of metal pipes, and acids to remove drilling mud damage.

There are several steps during the hydraulic fracturing process. Taken together, these steps constitute one stage. Horizontal wells that are completed by hydraulic fracturing typically have several stages. Stages are not completed simultaneously. After the first stage is complete, the pressure is reduced, and the downhole equipment is moved to setup the second stage. When ready, the pressure is increased for the second stage.

In addition to the EPA's Draft Assessment, state governments have also initiated independent analyses of the potential environmental impacts of hydraulic fracturing, with an emphasis on water quality. Many states and some local governments have enacted or revised laws or ordinances specifically addressing hydraulic fracturing, including in some cases moratoria or bans on further use of the technique. 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. These governmental requirements have kept oil and natural gas development as one of the most highly regulated industry sectors in the U.S. Industry practice continues to focus on reducing the risks associated with all stages of oil and natural gas development, including hydraulic fracturing.

Finally, the oil and natural gas industry has sought to continually reduce the risks associated with oil and gas development, including those to worker and public safety, water quality, air quality, endangered species, legacy impacts from fields that are no longer producing, and the incidence and severity of spills. Some of this information is publicly-available, but some is the result of self-monitoring and resides only in company records.

SECTION 3

Regulatory Framework

The SAB suggests that the EPA's Draft Assessment would be strengthened by including a discussion of state regulatory standards that have changed the probability of risk of water quality impacts associated with hydraulic fracturing. The SAB stated "the EPA should also discuss: (1) federal, state and tribal standards and regulations implemented with the aim of minimizing the potential impacts to drinking water resources associated with hydraulic fracturing operations, and (2) the evolution of oilfield and federal, state and tribal regulatory practices relevant to [hydraulic fracturing] activities" (SAB 2016). This section discusses the regulatory framework which addresses the potential impacts to water resources. Sections 4 through 8 of this report discuss the evolution of oilfield practices.

3.1 FEDERAL REGULATORY DEVELOPMENTS

There are extensive federal and state laws and regulations that govern oil and natural gas development in the United States. These are intended to promote safe and responsible development of oil and gas reserves in a manner that is protective of human health and the environment. At a federal level these protections include such major legislation as the Clean Air Act, Clean Water Act, Safe Drinking Water Act, Occupational Safety and Health Act, National Environmental Protection Act, Endangered Species Act, and the Oil Pollution Act. Other federal regulatory requirements are provided in Occupational Safety and Health, Department of Transportation, Federal Energy Regulatory Commission, and Department of Interior regulations, among others. The Federal government has recently proposed two regulations specific to hydraulic fracturing. One governs hydraulic fracturing on BLM and tribal lands and the second addresses chemical disclosure. Neither regulation has been finalized nor taken effect (one is involved in litigation and the latter is still being finalized). Most regulations related to hydraulic fracturing depend on local conditions, and both state and local regulatory frameworks are best positioned to address them.

Similarly, in May 2016 the Obama Administration released the Final Draft Methane Regulations that require oil and natural gas companies to further address methane emissions from new and modified sources. The EPA is utilizing an Information Collection Request (ICR) process to acquire data from oil and natural gas companies that will assist in the development of comprehensive regulations to reduce methane emissions from existing sources.

3.1.1 BLM Rule – Oil and Natural Gas: Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands.

The BLM's existing hydraulic fracturing regulations are found at 43 CFR 3162.3-2. These regulations were established in 1982 and last revised in 1988. On March 20, 2015, the Department of Interior released the final rule to provide additional regulation of hydraulic fracturing activities on public and tribal lands. Due to ongoing litigation the rule has been stayed. The rule that was proposed in 2015 would overlap with state regulations, and would focus on:

- Provisions for ensuring the protection of groundwater supplies by requiring a validation of well integrity and cement barriers between the wellbore and water zones through which the wellbore passes;

- Increased transparency by requiring companies to publicly disclose chemicals used in hydraulic fracturing to the Bureau of Land Management through the website FracFocus, within 30 days of completing fracturing operations;
- Higher standards for interim storage of recovered waste fluids from hydraulic fracturing to mitigate risks to air, water and wildlife; and
- Measures to lower the risk of cross-well contamination with chemicals and fluids used in the fracturing operation, by requiring companies to submit more detailed information on the geology, depth, and location of preexisting wells to afford the BLM an opportunity to better evaluate and manage unique site characteristics (BLM 2015).

As described in the analysis below of the state regulations pertaining to hydraulic fracturing, the BLM rule is duplicative of these provisions.

3.1.2 Advance Notice of Proposed Rulemaking under Section 8 of the Toxic Substances Control Act– Hydraulic Fracturing Chemical Disclosure

On May 9, 2014, in response to a rulemaking petition from non-governmental organizations, the EPA issued an Advance Notice of Proposed Rulemaking (ANPR) under Section 8 of the Toxic Substances Control Act (TSCA). The ANPR marked the beginning of the public participation process, and the EPA sought comment on a number of issues related to hydraulic fracturing chemical disclosure.

Public comments were accepted by EPA through August 18, 2014. The EPA is currently evaluating the submitted comments as it considers appropriate next steps. A final rule has not been issued to date. Many oil and natural gas-producing states have enacted regulations requiring chemical disclosure, as described in detail in 3.2.1 below.

3.2 SUMMARY OF STATE REGULATIONS

EPA has delegated primacy to the states for the implementation and enforcement of a broad range of environmental regulations which are applied to oil and natural gas development; Pennsylvania is the only oil and natural gas producing state without primacy to implement the Underground Injection Control (UIC) program. Moreover, extensive state regulations take in to account local conditions to tailor requirements governing the development and production of oil and natural gas resources. State oil and gas regulatory agencies routinely initiate reviews of their regulatory programs in response to changing industry practices and technology.

The SAB identifies that lack of discussion by EPA 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 Interstate Oil and Gas Compact Commission, 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 natural gas activity and hydraulic fracturing activity in each state, and the specific geology of the formations and drinking water aquifers in each state. Specific regulations pertaining to hydraulic fracturing are those that are in addition to the regulations already enforced for oil and natural gas activity in each state. Table 3-1 lists the top ten oil and natural gas producing states in the U.S. based on the most recent annual data available 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% 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% 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. While other states have adopted chemical disclosure laws related to hydraulic fracturing, such as Idaho, South Dakota, and Tennessee, very little to no hydraulic fracturing activity has occurred in these states, most due to the location and accessibility of shale formations.

Table 3-1. States with the Greatest Oil and Natural Gas Production in the United States

Top Oil Producing States	Volume (1,000 barrels)	Top Natural Gas Producing States	Volume (million cubic feet)
Texas	1,262,011	Texas	7,953,343
North Dakota	428,550	Pennsylvania	4,214,643
California	201,738	Oklahoma	2,310,114
Alaska	176,240	Louisiana	1,980,287
Oklahoma	157,770	Wyoming	1,791,235
New Mexico	149,403	Colorado	1,631,390
Colorado	119,239	Arkansas	1,631,390

In Texas, the state ranked number one in both oil and natural gas production in the United States, wells 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. Finally, 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 natural 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.

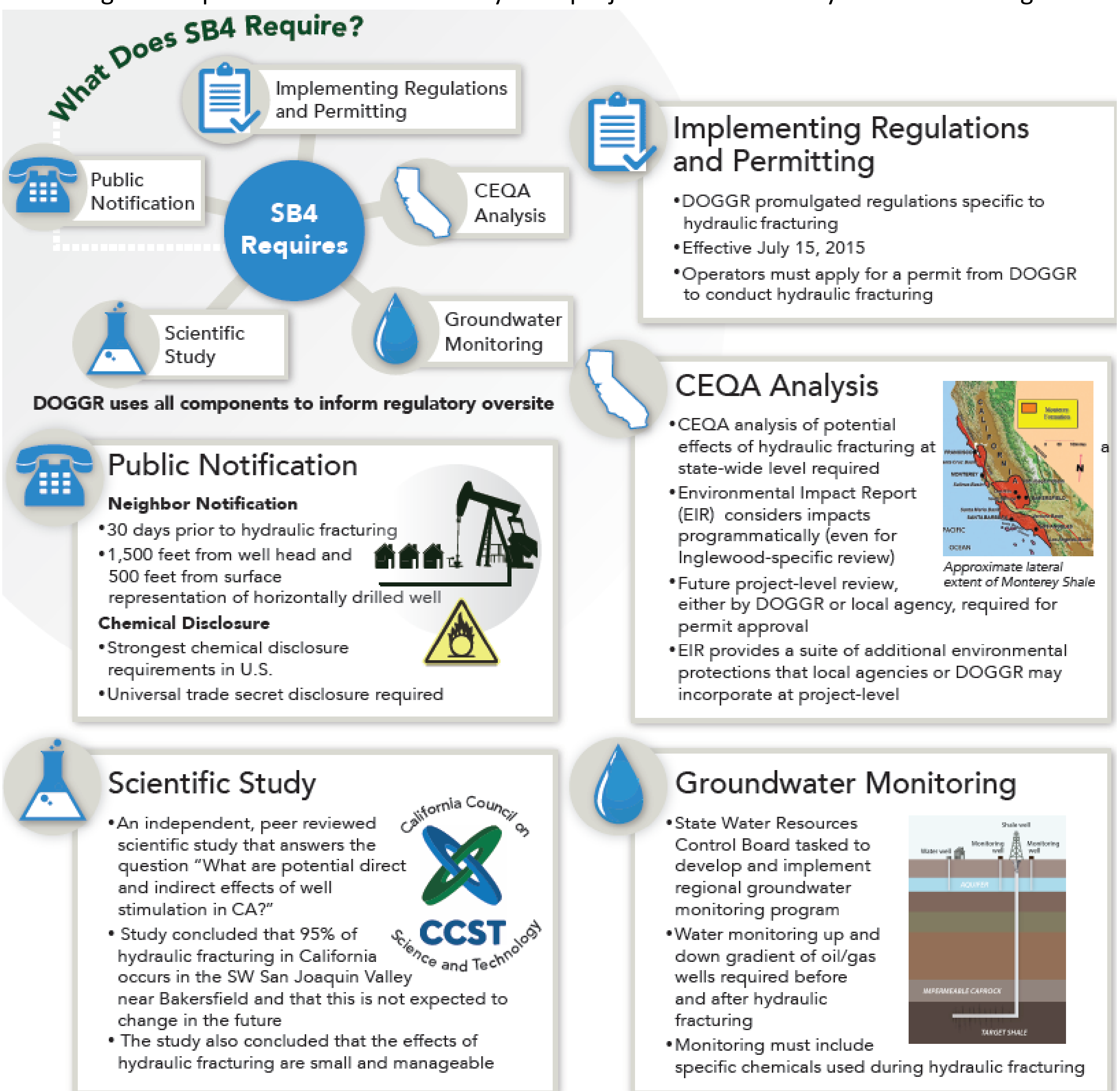
North Dakota, Pennsylvania, and Colorado require baseline groundwater quality analyses. North Dakota oil and natural gas rules also provide protections for landowners from groundwater contamination from all subsurface operations for all landowners with surface or groundwater rights within one mile of any oil and natural 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 was enacted in 2012 and represented a major update to the states oil and natural 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 third and fourth in oil production in the United States and both have 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 fourth 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.

California Regulation of Hydraulic Fracturing (SB4)

Senate Bill 4 (SB4), signed into law in 2013, regulates hydraulic fracturing in California. The law provides mechanisms for water monitoring, public disclosure of all chemicals used, and neighbor notification before well stimulation takes place. The regulations promulgated require CA's Division of Oil, Gas, and Geothermal Resources (DOGRR) to finalize and implement regulations and permitting requirements specific to well stimulation. It also requires the State Water Resources Control Board to develop and implement a regional groundwater monitoring program. SB-4 also mandated a comprehensive scientific study on the environmental impacts of hydraulic fracturing and requires environmental analysis of projects that include hydraulic fracturing.



Graphic created by Catalyst Environmental Solutions

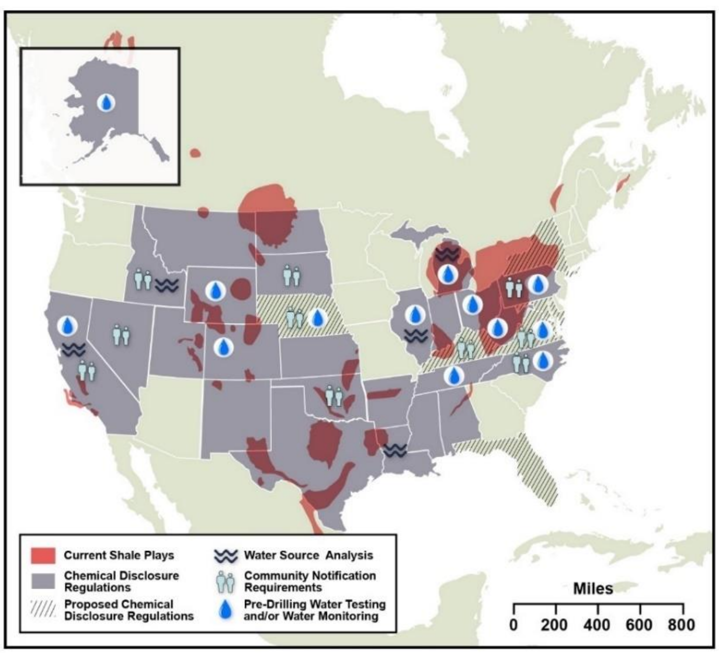
3.2.1 Chemical Disclosure

In September 2010, Wyoming was the first state to propose a chemical disclosure regulation for hydraulic fracturing. As depicted in Figure 3-1 (which includes the top 10 oil and natural gas producing states, along with other states with less unconventional activity), currently 25 shale oil and natural gas producing states have chemical disclosure regulations, and four states have proposed disclosure regulations.

These regulations are generally consistent from state to state, although each state differs slightly. For example, most states' regulations offer protection of trade secrets from disclosure, consistent with existing federal and individual state trade secrets laws and regulations. Some states require disclosure of propriety information to regulatory agencies, but not the public. Trade secret protection allows a company to protect their intellectual property rights, and preserve a competitive advantage; trade secrets include Google's search algorithm, the formula for Coca Cola, and the recipe for Twinkies. Trade secrets have also applied to some formulations of hydraulic fracturing fluids, and do not apply in case of medical emergencies.

FracFocus is managed by the Groundwater Protection Council and Interstate Oil and Gas Compact Commission and was developed in 2011 as a forum for disclosure of chemicals used in hydraulic fracturing. At its beginning, data was submitted to FracFocus on a voluntary basis by companies conducting hydraulic fracturing operations; however, it has since been adopted as the repository for chemical disclosure information by most states that require disclosure.

Table 3-2 summarizes the key provisions of the chemical disclosure regulations of the states that have enacted or proposed chemical disclosure laws. The table is arranged in order of the states with the greatest production levels of natural gas to least production (2014 data; U.S. Energy Information Administration 2016).



Graphic created by Catalyst Environmental Solutions, 2016.

Figure 3-1. State Chemical Disclosure Requirements

Table 3-2. Summary of State Chemical Disclosure Regulations

State	Date Enacted	Enforced By	Reporting Required	Volume or Concentration Reporting Required	Trade Secrets Chemical Disclosure	Regulatory Code
Texas	Feb-12	Texas Railroad Commission	All chemicals used in hydraulic fracturing	For hazardous chemicals only	Disclosure not required. Provides access to trade secret information in event of medical	16 Tex. Admin. Code § 3.29(c)-(f). February 1, 2012
Pennsylvania	Feb-12	Pennsylvania Department of Environmental Protection	All fracturing additives and chemicals All hazardous chemicals (as defined by OSHA) used on well-by-well basis	For hazardous chemicals only	Must disclose chemical family. Provides access to trade secret information in event of medical	58 Pa. Cons. Stat. § 3222. April 14, 2012
Oklahoma	Aug-15	Oklahoma Oil and Gas Conservation Division	Description of medium to be injected	Volume and concentration of chemicals	Disclosure not required	Oklahoma Administrative Code, Title 165, Chapter 10
Louisiana	Oct-11	Louisiana Department of Natural Resources	All chemicals used in hydraulic fracturing	Concentration of all chemicals	Requires disclosure of chemical family only	Louisiana Admin. Code tit. 43, pt. XIX § 118 (2011). October 20, 2011
Wyoming	Oct-10	Wyoming Oil and Gas Conservation Commission	All chemicals used in hydraulic fracturing	Volume and concentration of chemicals	Disclosed to regulators; undisclosed to the public.	Wyoming Wyo. Code Rules and Regs. Oil Gen. § 45. October 17,
Colorado	Apr-12	Colorado Oil and Gas Conservation Commission	All chemicals used in hydraulic fracturing	Concentration of all chemicals	Requires disclosure of chemical family. Provides access to trade secret	Colo. Code Regs. §404-1:205A. April 1, 2012

New Mexico	Feb-12	New Mexico Oil Conservation Division	All chemicals used in hydraulic fracturing	Volume and concentration of chemicals	Disclosure not required	N.M. Code R. § 19.15.16.19(B). February 15, 2012
Arkansas	Jan-11	Arkansas Department of Environmental Quality	All chemicals used in hydraulic fracturing	None	Chemical family disclosed to public. Provides access to trade secret information in event of medical	178-00 Ark. Code R. §001:B-19. January 15, 2011
West Virginia	Dec-11	West Virginia Department of Environmental Protection	All chemicals used in hydraulic fracturing	None	Disclosure not required	W. VA. Code § 22- 6A-1 et seq.12 December 11, 2011
Ohio	Sept-12	Ohio Department of Natural Resources	All chemicals used in hydraulic fracturing	Volume and concentration of products	Disclosure not required. Provides access to trade secret information in event of medical	Ohio Rev. Code §1509.10.8. September 10, 2012
Utah	Nov-12	Utah Board of Oil, Gas, and Mining	All chemicals used in hydraulic fracturing	Volume and concentration of chemicals	Not specified	Utah Code Ann. § 649-3-39. November 1, 2012
Alaska	Dec-14	Alaska Oil and Gas Conservation Commission	All chemicals used in hydraulic fracturing fluid	Volume and concentration of each chemical ingredient	Disclosure required to regulators but maintained confidential	Alaska Administrative Code, Chapter 25, Sections 005, 280, 990, 283
North Dakota	Apr-14	North Dakota Department of Mineral Resources	Injection fluids	Volume and "nature" of injection chemicals	Disclosure not required	North Dakota Century Code; Chapter 38, Section IV.
Kansas	Sept-15	Kansas Oil & Gas Conservation Division	Maximum concentrations of each fluid	Volume and concentration of fluids	Must disclose chemical family	Kansas General Rules and Regulations, Chapter 82-3.

California	Jan-14	California Division of Oil, Gas & Geothermal Resources	All chemicals used in hydraulic fracturing	Volume and concentration of chemicals	Disclosure not required, although non-disclosure protections less extensive as a result of SB-4. Provides access to trade secret information in	California Legislature. Senate Bill 4. Enacted January 2014.
Alabama	Jan-14	State Oil & Gas Board of Alabama	Description of additives to be used in fracturing fluid	Volume and concentration of fluids	Disclosure not required	Alabama Administrative Code, Chapter 400-3-4.
Virginia	Proposed (Sept-16)	Virginia Department of Mines, Minerals, and Energy	All chemicals used in hydraulic fracturing	None	Disclosure not required	Gas and Oil Regulations 4VAC 25-100
Michigan	Jun-11	Michigan Department of Environmental Quality	All hazardous chemicals (as defined by OSHA)	For hazardous chemicals only	Disclosure not required	Michigan Administrative Rules, Part 615, Section 324. March 11, 2015.
Kentucky	Proposed (Dec-15)	Kentucky Division of Oil and Gas	All chemicals used in hydraulic fracturing	Concentration of each additive.	Disclosure not required	Kentucky House Bill 386, December 16, 2015.
Montana	Aug-11	Montana Board of Oil and Gas Conservation	All chemicals used in hydraulic fracturing	Concentrations of additives	Disclosure not required. Provides access to trade	Mont. Admin. R. 36.22.1015. August 27, 2011.
Mississippi	Aug-14	State Oil & Gas Board of Mississippi	All chemicals used in hydraulic fracturing	Volume and concentration of chemicals	Must disclose chemical family.	Mississippi Rules of Procedure, Title 53, Rules 25, 26, and 47.
South Dakota	Apr-13	South Dakota Board of Minerals and Environment	Ingredients intentionally included in hydraulic fracturing fluid mix	Maximum concentrations of all fluids	Disclosure not required	S.D. Admin. R. 74:12:02:19. April 22, 2013

Indiana	Aug-12	Indiana Natural Resources Commission	All chemicals used in hydraulic fracturing.	Concentration of each additive.	Disclosure not required	7 Indiana 312 Ind. Admin. Code 16-3-2 (2012). August 1, 2012
Tennessee	Jun-13	Tennessee State Board of Water Quality	All chemicals used in hydraulic fracturing	Maximum concentrations of each fluid	Disclosure not required	Tennessee Tenn. Comp. R. & Regs. 0400-53-01- .03. June
Illinois	Nov-14	Illinois Department of Natural Resources	All chemicals used in hydraulic fracturing	Concentrations of each fluid	Disclosed	Illinois Administrative Code, Title 62, Chapter 1, Part 240
Nebraska	Proposed (Apr-13)	Nebraska Oil and Gas Commission	All chemicals used in hydraulic fracturing	None	Disclosure not required	Nebraska L.B. 877 (Proposed Legislation).
Florida	Proposed (Jan-16)	Florida Department of Environmental Protection	All chemicals used in hydraulic fracturing	Concentration of each additive	Disclosure not required	Florida House Bill 191. January 26, 2016
Nevada	Jun-13	Division of Minerals and Division of Environmental Protection	All chemicals used in hydraulic fracturing	Volume and concentration of fluids	Disclosure not required	Nevada Regulatory Statute 522.119. 2013.
Idaho	Mar-12	Idaho Department of Lands	All chemicals used in hydraulic fracturing	Concentrations of additives	Operators can request trade secret protection	Idaho Admin. Code r. 20.07.02.056
North Carolina	May-14	North Carolina Oil and Gas Commission	All chemicals used in hydraulic fracturing	Volume and concentration of fluids	Disclosure to State Geologist, but not released to public.	North Carolina S.L. 2014-4. April 2014.

Note: States are presented in order of the volume of natural gas produced in each state based on the most recent annual data available (2014). No natural gas or crude oil production was reported in Idaho or North Carolina in 2014.
Of the states listed above, Colorado, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and California mandate reporting to the FracFocus registry, while Louisiana, Michigan, Montana, and Ohio allow reporting to either FracFocus or the state, and the other states require reporting to state agencies.

3.2.2 Water Quality Monitoring

Eleven states have regulations pertaining to baseline and on-going water quality monitoring in areas of hydraulic fracturing (Figure 3-2.), including four of the top producing states (California, Colorado, Wyoming, and Pennsylvania). Many of these regulations have been enacted between 2012 and 2016, apparently in response to the rise in hydraulic fracturing activities. 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.

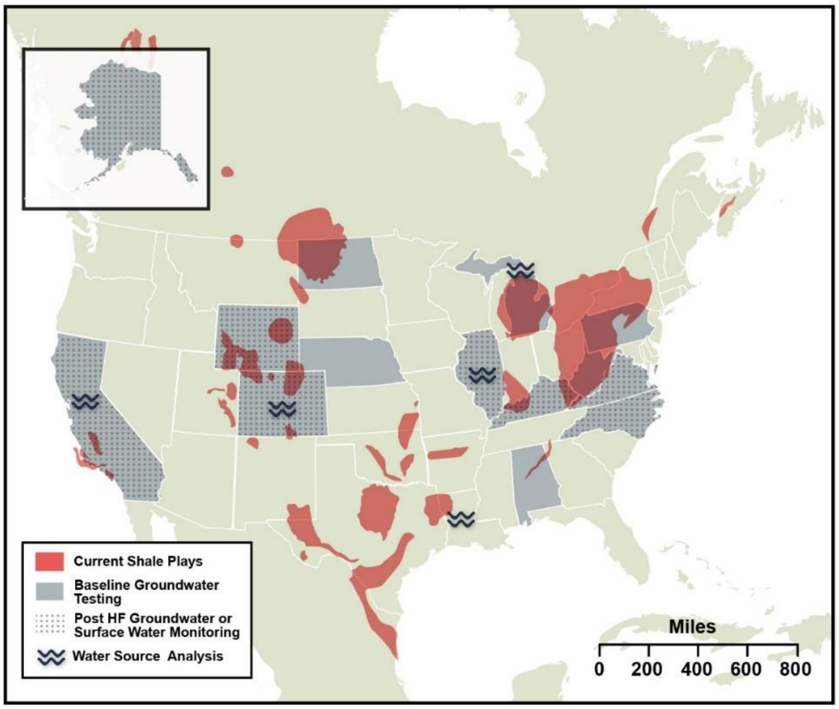


Figure 3-2. State with Water Quality Monitoring and Source Assessment Requirements

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. Colorado also has specified setbacks and precautions for hydraulic fracturing near surface waters and tributaries that are sources of public drinking 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 their water use would adversely impact rivers or streams. If there is a water supply well within 1,320 feet of a proposed withdrawal, the operator is required to install a monitoring well. In addition to the requirement to install new monitoring wells, oil and natural gas operators are also required to collect baseline samples from a maximum of 10 water supply wells within 1,320 feet of the oil and natural gas wells, six months or less before drilling operations begin (Michigan DEQ 2014).

Four states (Ohio, Pennsylvania, 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. Similarly, 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 natural 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).

3.2.3 Additional State Regulations

Table 3-3, below, summarizes the broader regulatory landscape for hydraulic fracturing across the U.S. All states with oil and natural gas production have regulated hydraulic fracturing, for several decades through their existing oil and natural gas regulatory framework. As unconventional development has rapidly grown, states have developed additional provisions to add to their oil and natural 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.

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Table 3-3. 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	Fluid 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	Allowed	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	N	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	Allowed, except in a 1,150 sq-mile area north of Conway along a fault line	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	Allowed	N	3+

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	Fluid Disclosure Required	Fluid Storage Regs	Freeboard Regs	Pit Liner Regs	Flowback/ Wastewater Transportation Tracking	Underground Fluid Injection	Accident Reporting Requirements	# of regulating Agencies
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
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	Address ed in Permit	Y	Y	Y	Allowed	Y	2
California	252,718	201,738	Y	Permit Required	Other Setback Requirement s	Other Setback Requirement s	Y	Y	Y	N	Y	Y	N	N	N	Allowed	N	3+
Alabama	181,054	9,734	N	Registratio n 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/appro val	Allowed	Y	1
Kentucky	2,862	78,737	N	N	Y	N	N	Y	Y	Discretionar y 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

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	Fluid Disclosure Required	Fluid Storage Regs	Freeboard Regs	Pit Liner Regs	Flowback/ Wastewater Transportation Tracking	Underground Fluid Injection	Accident Reporting Requirements	# of regulating Agencies
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 - No Reg Flaring - restricted	Y	Y	N	Y	Y	Allowed	Y	2
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	N	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

3.2.4 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 Interstate Oil and Gas Compact Commission (IOGCC) and EPA. The EPA, U.S. 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 natural 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 (August 2016), 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 natural 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 3-4 summarizes the results of the eight STRONGER reviews that have been conducted since 2011, when the hydraulic fracturing review guidelines were first implemented.

Table 3-4. 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]	
Comprehensive regulatory standards for hydraulic fracturing have been developed which: (see following cells).	Reporting requirements should include volumes of hydraulic fracturing fluids and proppants used, pressures recorded, and hydraulic fracture materials used.
Prohibits pollution of a fresh water from well completion activities.	Recycling of flowback water and use of alternate, lower quality water should be encouraged.

Provides minimum casing and cementing standards.	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.

Sources

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[8] State Review of Oil & Natural Gas Environmental Regulations (STRONGER). Pennsylvania Hydraulic Fracturing State Review. 2013. Available online at: http://www.strongerinc.org/wp-content/uploads/2015/04/Final-Report-of-Pennsylvania-State-Review-Approved-for-Publication.pdf

SECTION 4 **Water Acquisition**

Water is a significant component of all hydraulic fracturing operations because it is injected into a formation at high pressures to fracture the rock. However, the amount required varies 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). The EPA Draft Assessment finds that the national median volume of water used per hydraulically fractured well is approximately 1.5 million gallons, according to analysis of FracFocus disclosures.

The EPA Draft Assessment addresses whether water acquisition for hydraulic fracturing has the potential to directly impact water quantity and availability, and indirectly impact water quality. A combination of factors determines whether hydraulic fracturing introduces imbalance in the relationship between water supply and demand in a region, including availability of water resources and their capacity to yield water, total water demand in the area including the oil and natural gas industry, and the geologic characteristics of rocks in each basin.

4.1 SUMMARY OF EPA FINDINGS

The EPA Draft Assessment finds that in general, hydraulic fracturing uses less than 1% of total annual water use at the state and county level. In a survey of published literature EPA did not find a single case in which hydraulic fracturing water consumption caused a drinking water well or a stream to run dry. The EPA Draft Assessment notes that the potential for impacts are highest in areas with relatively high hydraulic fracturing water use and low water availability. However, the EPA Draft Assessment further notes that water availability is rarely impacted by just one factor or use; it is inherently a multi-use issue. The EPA Draft Assessment bases its conclusions on state data primarily, supplemented with some county level data.

In instances where hydraulic fracturing reduces water quantity it can also indirectly impact water quality. For example, just as in all pumping of water from wells, when groundwater withdrawal rates exceed recharge rates then contaminants in a groundwater aquifer may, rarely, be oxidized and mobilized, or lower quality water from adjacent formations may be drawn in, diminishing groundwater quality. Similarly, reducing surface water flow can reduce dilution potential and thereby diminish water quality (EPA 2015a).

4.2 SUMMARY OF SAB COMMENTS

The SAB's primary comment regarding the EPA's analysis of the potential impacts of water acquisition is that a national-level analysis is not appropriate, and that state and county level data may be too coarse. The SAB comments emphasize that "many stresses on water resources are expected to be localized in space and temporary in time but can be important and significant, and should not understate the potential for localized problems associated with such stresses". The SAB concludes that the final Assessment Report "needs to better recognize the importance of local impacts." (SAB 2016).

The SAB notes that the EPA Draft Assessment should aim to gather and synthesize data at smaller spatial and temporal scales, such as data from state databases that may not be available in mainstream data bases, well completion reports, or permit applications. Such data could provide a clearer picture of local water use to further elucidate the potential for localized impacts (SAB 2016).

4.3 INDUSTRY PRACTICES AND REGULATORY PROGRAMS

The SAB's primary concern with the water acquisition analysis provided within the EPA Draft Assessment is that it does not analyze impacts at a local level. At any place, based on specific local circumstances, it is possible that there may be an adverse effect based on acquiring water for hydraulic fracturing. The data at national, state, and local scales indicate that water acquisition does not lead to any widespread or systematic effects to water quantity. In areas where water is scarce, or where water acquisition has the potential for local effects, there is typically a regulatory program in place to minimize the likelihood of such effects. These programs balance the needs of all water users, in some states including ecosystem services. These regulatory programs appear to be adequate to address the SAB concern that EPA did not adequately address local effects. The remainder of this section provides further basis for this conclusion.

When water acquisition is analyzed at a more local level, such as a water district, the results are largely similar to a county level analysis provided in the Draft Assessment. The California Council on Science and Technology study of the effects of well stimulation in California (CCST 2015) evaluated water acquisition at the water district and planning area level, a finer level of detail than the county level. Planning Areas are, on average, 2,600 square miles and typically follow watershed boundaries. The CCST estimated the amount of water used for well stimulation and hydraulic fracturing by planning area and compared that to total water use in that planning area. The maximum water use for well stimulation was 0.19% of total water use in the California Semitropic Planning Area, and the average was 0.0057% of total water use across the 19 planning areas where hydraulic fracturing occurs (CCST 2015). These data are consistent with county level averages of the percentage of water dedicated to hydraulic fracturing cited in the EPA Draft Assessment. Based on the EPA Draft Assessment and these results, local effects at an even finer scale are expected to be unusual compared to these averages.

As noted in the EPA Draft Assessment, at the state and national level water consumed for hydraulic fracturing is less than 1% of total annual water use at these scales. According to the USGS, in 2014, the entire mining sector, including oil and natural gas activities and other mineral extraction, accounted for only 1% of the entire nation's water use. In comparison, electric power and agriculture accounted for 41% and 37%, respectively (Figure 4-1).

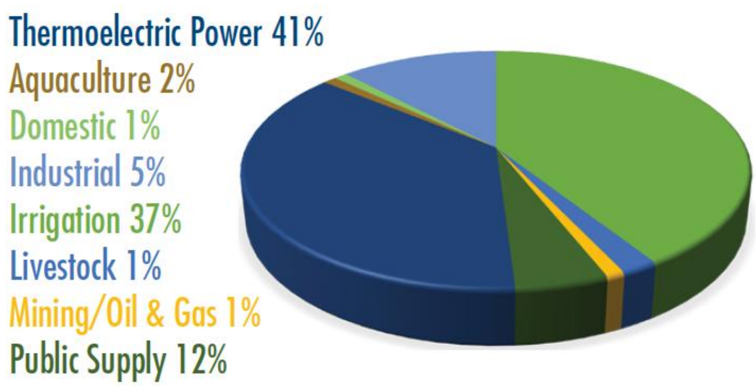


Figure 4-1. Percentages of water used Nationally per Industry

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 oil and natural gas, extracted by hydraulic fracturing, is relatively small when compared to other energy sources. For example, research has suggested that energy from a coal-fired power plant is 25-50 times more water intensive than natural gas extracted via hydraulic fracturing (Scanlon et al. 2013).

At a smaller spatial scale, 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 natural gas activity in the same area is 8.4 million gallons per day (Fracfocus.org). Any impact associated with water withdrawals are, therefore, not unique to hydraulic fracturing but are applicable to all industries that utilize large volumes of water. Among these large users of water, the Oil and Gas category is less than one percent.

The conclusions are similar when focusing on the county level scale. Hydraulic fracturing water use represented less than one percent of fresh water available in over 300 of the 395 counties analyzed in the EPA Draft Assessment, mirroring state and national statistics and suggesting that there is ample water supply at the county level for hydraulic fracturing operations. However, according to the EPA Draft Assessment 17 counties, all located in Texas, exhibited hydraulic fracturing water use in excess of freshwater availability. In addition, there may be instances where hydraulic fracturing is one of the only water uses in an area, in which the percentage of water consumed by hydraulic fracturing would be higher. For example, water used for hydraulic fracturing in Wise and Johnson counties in Texas' Barnett shale represented 19% and 29% of the counties' respective total water use (Freyman and Salmon 2013). Similarly, as one studies progressively smaller geographic scales then it is possible that in limited cases water withdrawals for hydraulic fracturing could impact local water quantity. However, this would not be a widespread or systematic occurrence of water acquisition.

There are a several industry best management practices, trends, and local regulations that help reduce this unusual occurrence, as described below.

4.3.1 Water Source

Two of the most important considerations in determining the potential impacts of hydraulic fracturing on water quantity are the water source and the general availability of water in the region, which both vary by region. Figure 4-2 illustrates water availability across the United States.

Historically, the two primary water sources are groundwater and surface water. In general, in the wetter eastern states water resources are well distributed and available year-round. As such, water is typically sourced from surface water. In the drier Midwestern and western states, groundwater use is more commonplace. Table 4-1, below, shows the source of hydraulic fracturing water in several shale basins across the country. In some locations, such as Pennsylvania, water comes almost exclusively from surface waters. In some basins in Texas there are instances where water is entirely sourced from groundwater aquifers, while in a neighboring basin there is an equal distribution between groundwater and surface water, illustrating that water source is highly variable and regional.

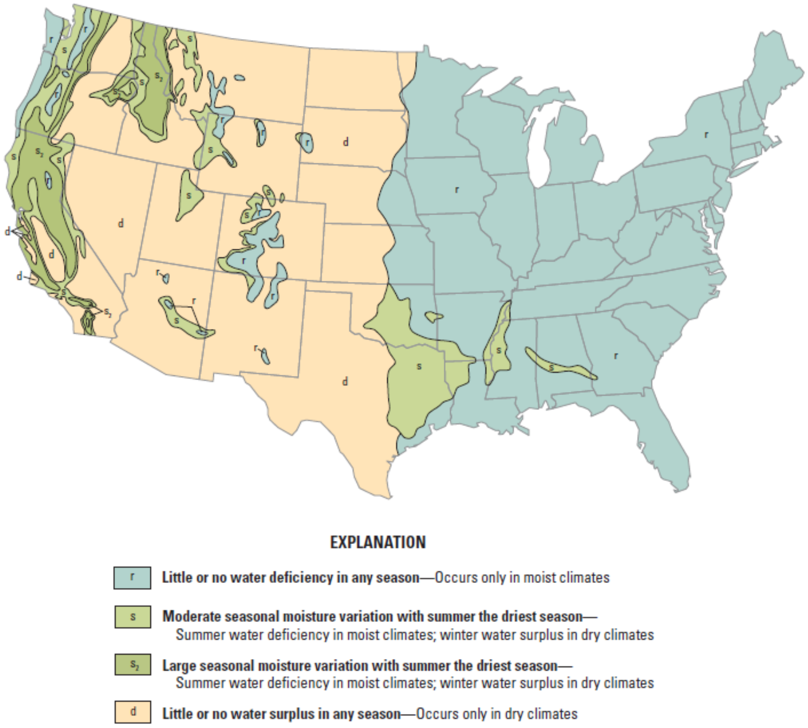


Figure 4-2. Water Availability in U.S. (Reilly et al. 2008)

Table 4-1. Source of Water Used for Hydraulic Fracturing in Key States

Location	Surface water	Groundwater
Texas—Barnett Shale	50%	50%
Texas—Eagle Ford Shale	10%	90%
Texas—TX-LA-MS Salt Basin	30%	70%
Texas—Permian Basin	0%	100%
Texas—Anadarko Basin	20%	80%
Pennsylvania—Marcellus Shale, Susquehanna River Basin	78%	22%
West Virginia—Statewide, Marcellus Shale	91%	9%
Oklahoma—Statewide	63%	37%
Louisiana—Haynesville Shale	87%	13%

Source: EPA 2015a

4.3.2 Operational Practices

API RP 100-2 - *Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing* (API 2015b) summarizes industry practices associated with water source for shale gas development, as follows: When investigating potential options for securing water supplies to support hydraulic fracturing operations, awareness of competing water needs, water management issues, and the full range of permitting and regulatory requirements in a region is critical. Oil and natural gas companies are increasingly initiating proactive communication with local water planning agencies and the public, where appropriate, to ensure that oil and natural gas operations do not disrupt local community water needs. Understanding local water needs helps in the development of water acquisition and management plans that will be acceptable to the communities neighboring oil and natural gas development. Potential cumulative impacts are minimized or avoided by working with local water resource managers to develop a plan of when and where withdrawals will occur (API 2015b).

Other operational practices are also identified in API RP 100-2 (API 2015b), the application of which is dependent on local conditions. To minimize impacts associated with surface water withdrawals operators frequently consider implementing water withdrawal programs, in association with the local water management authority, to make use of seasonal changes in river flow. This planning helps operators capture water when surface water flows are greatest, by using a large-scale water diversion and storage impoundments. Another simple method that is sometimes used is to excavate low lying areas to harvest rain water.

To reduce impacts on groundwater in drier parts of the country, operators have drilled dedicated deep wells (to more saline zones beneath fresh water aquifers and in more saline zones) to collect non-potable groundwater for well stimulation. For example, in the Fort Worth Basin domestic and municipal water wells utilize the Upper Trinity aquifer for fresh water supply. Operators working in the Barnett shale in the Fort Worth Basin are drilling wells to the Lower Trinity aquifer to supply water for drilling and hydraulic fracturing. The Lower Trinity aquifer water has a higher total dissolved solids (TDS) content that would not be suitable for domestic use without extensive water treatment (API 2015b). These techniques relieve potential stress on potable water supplies.

4.3.3 Industry Trends

4.3.3.1 Hydraulic Fracturing with Non-Freshwater Sources: Technological Advancements and Trends

Water quality is an important consideration when sourcing water for hydraulic fracturing fluids. Historically, fresh water has been preferred to (1) maximize hydraulic fracturing fluid performance, (2) ensure compatibility with the geologic formation being fractured, and (3) safeguard well integrity, especially from corrosion. As knowledge of a basin's characteristics and the best chemical mix to respond to those characteristics matures, it is then sometimes feasible to rely on brackish or recycled water sources. With advances in fracturing fluid design, hydraulic fracturing with brackish sources is becoming not only feasible, but common place. The trend in the oil and natural gas industry is to use greater volumes of recycled water and/or brackish water for hydraulic fracturing, reducing the demand on existing freshwater resources.

The two basic fracturing fluid methods use either slickwater or crosslinked gels. Selecting a fracturing fluid depends primarily on the target formation properties and the type of fracture desired. The total volume of water and water quality required to perform slickwater versus crosslinked gel hydraulic fracturing can vary significantly. For any given fracture length, a slickwater fracture requires high water volumes but can utilize water with lower quality than cross-linked fractures. The chemicals used in cross-linked fracturing fluids can interact with the chemistry of the source water, requiring higher water quality. However, cross-linked fracturing fluids create a higher viscosity gel that entrains greater sand concentration and therefore require less water overall. Slickwater, on the other hand, relies on high volumes of water with lower sand concentrations that are injected at high pressures to maintain the sand velocity and propagate the fractures. As such, the chemical composition of the source water is less critical for slickwater, and the use of brackish, saline or other non-freshwater sources is feasible. The understanding of the chemical properties of fracturing fluids has improved dramatically in recent years, and industry has made significant progress in developing fracturing fluids that allow for the use of brackish water, reducing demand on potable water supplies (CH2M Hill 2015).

Innovation in water treatment technology continues to allow use of recycled produced water and flowback water for hydraulic fracturing operations. In addition, operators experiment with and determine the optimum mix of additives to most effectively produce from each shale play. This chemical mixture can vary significantly even between different plays located in the same basin, or the same play located in adjacent basins. In general, as the application of hydraulic fracturing in particular shale basins has matured, the optimal chemical mixture provided by service companies tends to become standard. In addition, as basin-specific knowledge of the optimum chemical mix is determined, the use of recycled water as source water can also be increased.

Not only has utilizing non-potable water for hydraulic fracturing becoming more technologically feasible, government and industry are embracing these advancements. API also promotes considering non-potable water for hydraulic fracturing whenever possible. API urges operators to ensure that the non-potable water quality is suitable for the specific shale formation. Industry trends show movement towards using non-freshwater sources for hydraulic fracturing, reducing strain on freshwater sources.

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;
- Power plant cooling water;
- New diversion of surface water;
- Groundwater diverted from wells;
- Produced water; and
- Recycled construction water.

In evaluating water requirements for hydraulic fracturing, the operator increasingly conducts a comprehensive evaluation of cumulative water demand on a programmatic basis, as well as the timing of these water needs at an individual well site (COGCC 2012).

Case Studies in Non-Freshwater Use for Hydraulic Fracturing

Case Study 1: In 2013 an operator conducting hydraulic fracturing operations in the Eagleford Shale used brackish water for 75% of its water needs, saving more than approximately 22 million gallons of fresh water. The quality of the brackish water used in operations ranged from Class 2a water (acceptable for crops and livestock but not recommended for drinking) to Class 3 water (recommended only for slickwater injection). Table 4-2, shows the breakdown in water types used in one operator's 2013 Eagleford Shale operations (CH2M Hill 2015).

Table 4-2. Water Use for Hydraulic Fracturing by Quality Classification

Water Classification	Quality	2013 Consumption	Description
Class 1	Fresh	25.1%	Unrestricted use for drinking, agriculture, or livestock
Class 2a	Brackish	25.7%	Not recommended for drinking, acceptable for all livestock and crops except sensitive plants (e.g., corn)
Class 2b	Brackish	20.1%	Not recommended for drinking, usable for livestock but not preferred, usable for crops with moderate tolerance (e.g., rye)
Class 2c	Brackish	17.6%	Not recommended except for very salt-tolerant plants, but expect yield reductions (e.g., barley)
Class 3	Brackish	11.5%	Not recommended for use (this is the permissible limit for a slickwater development [SWD] injection zone)

Source: CH2M Hill 2015

Case Study 2**:** In the Barnett area of Texas, 100% of a prominent operator's hydraulic fracturing water is brackish. Moreover, the operator is trending towards recycling a higher percentage of produced water for future fracturing jobs, with the goal of creating a closed loop cycle. Recycled water accounted for only 25% of total water used for hydraulic fracturing in 2013, but in the first quarter of 2014 approximately half of the total water used for hydraulic fracturing was sourced from recycled sources (Figure 4-3) (CH2M Hill 2015).

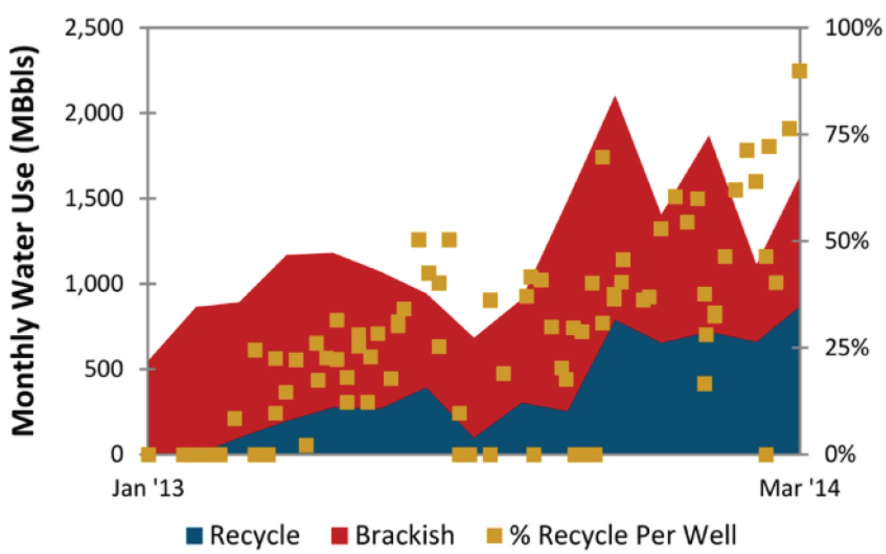


Figure 4-3. Brackish and Recycled water use in Barnett shale fracturing operations

Case Study 3**:** Since 2011 an operator working in Wyoming's Green River Basin, where over a third of the companies' proven reserves are located, has been using recycled water for nearly 100% of its hydraulic fracturing operations. This is a 50% increase from 2008, when recycled water use was only approximately 65%. The operator increased use of recycled water by constructing and operating a liquids gathering system. The facilities in the system are able to treat the produced water to different standards depending on identified requirements. There is a permanent centralized treatment facility to treat produced water and multiple smaller onsite facilities to treat flowback water. The systems are used by multiple operators working in the area. This recycling not only reduces the amount of freshwater needed for development, but also reduces truck traffic, benefitting air quality and wildlife in the area (CH2M Hill 2015). Note that the beneficial reuse of produced water, including recycling for future fracturing operations, is discussed further in Section 5.2.

4.3.3.2 Water Management Groups Optimize Water Use.

Many exploration and production companies are introducing dedicated water resources staff into their organizational structures. Staff at a corporate level tend to focus on water strategic planning and standardization, while managers at a local level focus on day-to-day water optimization. Many companies take a water life cycle approach aiming for continual improvement at every stage of the hydraulic fracturing water cycle. For example, one operator has a dedicated water team for each shale play in which it operates that is responsible for planning and sourcing water based on water needs and constraints specific to that play. There is also a corporate water group that is responsible for implementing programs such as the operator's Freshwater Net Neutral Imperative. Similarly, another operator has created a Water Management LLC, dedicated to meeting the company's water needs in West Texas. This subsidiary is focused on reducing the company's reliance on freshwater use during well drilling and hydraulic fracturing. The water management group has already successfully increased sourcing from the operator's drilled brackish water wells as well as from other non-freshwater sources. The company plans to have enough excess water capacity to be able to deliver water to other operators working in the same area. As stated by the President of the Water Management LLC, "Without a dedicated and empowered team focusing on water management…major improvements to operations would be difficult to achieve" (CH2M Hill 2015). This view tends to be shared by many major and large independent oil and natural gas companies, as indicated by the strong trend toward dedicating labor and financial resources towards water resource optimization.

Data Management Helps Reduce Impacts Associated with Water Acquisition

One operator tracks surface withdrawals based on flows recorded by U.S. Geological Survey (USGS) meters, which the operator partially funds. This collaborative arrangement has enabled the USGS to gather and publish more stream data from areas where previously there had not been monitoring. The withdrawal system is monitored via Supervisory Control and Data Acquisition (SCADA) and is programmed to automatically shut down when the stream flow does not meet the USGS metered pass-by conditions set by the Susquehanna River Basin Commission (SRBC).

Another operator has developed a standard truck filling station at impoundments. All hydrant filling stations are metered and connected to SCADA to provide detailed and accurate data that identify each truck, its filling activities and capacity, and its current settings. The hydrant truck drivers manually open one valve, and the system automatically fills the truck based on a pre-programmed truck volume for that specific truck.

In addition, river intake parameters are automatically monitored via SCADA. Red indicator lights at the hydrants indicate when stream pass-by flow conditions are not being met (CH2M Hill 2015).

4.3.3.3 Data Management and Transparency

Oil and natural operators have been developing and utilizing increasingly sophisticated data management systems to track water use and optimize management. The data management systems track from water source to transportation via truck and/or pipeline through storage and flowback and produced water management and disposal. The data management systems improve data collection, analysis, and public disclosure. They also allow operators to make more informed water management decisions and strive for continuous improvement (CH2M Hill 2015).

4.3.4 Regulations

Most states have regulatory frameworks in place to control water acquisition and minimize potential impacts to water resources associated with water withdrawals, seeking to balance demand with sustainability, which includes consideration of ecosystem services in some states or watersheds. Regulations consider the water quantity available, and the effects of withdrawal on the water source. In general, in the wetter eastern states water for hydraulic fracturing is primarily sourced from surface waters, while drier Midwest and western states tend to rely more heavily on groundwater. As such, each state's regulatory framework has been developed to focus on the primary water sources. Withdrawals from groundwater, frequently require permits from county, state or multi state regulatory agencies (API 2015b). For instance, California requires detailed information on the source of base fluid water to be included in the permit application submitted to the Division of Oil, Gas and Geothermal Resources and concurrence by the applicable state and regional water resources agencies. In Louisiana, groundwater supply is scarce and operators are encouraged to use surface water supplies; all applications require an assessment of the environmental impacts of water use and the water sources and volumes must be reported for wells that are hydraulically fractured. Other states that specifically require operators to disclose the source of water used in hydraulic fracturing are Arkansas, Idaho, Illinois, Indiana, and Michigan.

Water rights vary by state. Many states have complex water rights systems, in which withdrawal rates are regulated based on the conditions of the water well permit and the water rights allocations. For example, in Colorado, the surface and ground water rights are based on the prior appropriation doctrine, which states that water extracted from any source must be reconciled with the prior appropriation system. North Dakota limits industrial groundwater withdrawals due to concerns about stressed groundwater supplies. In contrast, in the Susquehanna River Basin in Pennsylvania water resources are well distributed and available year round and hydraulic fracturing operators have been able to develop with 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. Water withdrawal permits can require compliance with specific metering, monitoring, reporting, record keeping, and other consumptive use requirements. In addition, permits regulate minimum stream flow requirements. If the flow rate in a stream is below certain thresholds, then water withdrawals are stopped and pass-by flows are required (CH2M Hill 2015).

This regulatory framework was developed to address all types of water withdrawal; the data indicate that the water demand of hydraulic fracturing is less than other demands within a planning area. Therefore, the existing state regulatory programs appear to be adequate to address the newer demands of hydraulic fracturing. Where water is scarce, the level of analysis is greater than in areas where water is abundant. A summary of state regulations pertaining to water use and water quality and hydraulic fracturing is included in Table 4-3.

Table 4-3. Summary of State Water Monitoring and Source Assessment Regulations Specific to Hydraulic Fracturing

State	Baseline Water Quality	Long-Term Groundwater Monitoring	Water Source Analysis	Regulatory Code
Alabama	Required to inventory all drinking water wells within ¼ mile	None	None	Alabama Administrative Code, Chapter 400-3-4.
Alaska	Required to sample all water wells within ½ mile.	May be required to sample water wells after HF, as determined by AOGC	None	Alaska Administrative Code, Chapter 20, Section 25. Effective January 2015
California	Water sampling conducted within 0.5 of well proposed for HF prior to operation (1 upgradient and 2	Following stimulation wells should be monitoring semi-annually.	Must provide detailed information on the source of base fluid water in permit application.	California Legislature. Senate Bill 4. Enacted January 2014.
Colorado	Requires operators to sample surface water resources within buffer zones prior to HF and within 3 months' after	None	None	Colo. Code Regs. §404- 1:205A. April 1, 2012
Idaho	None	None	Operators must submit detailed information on the source of base fluid protection	Idaho Admin. Code r. 20.07.02.056 (2012). March 29,
Illinois	Permittee must conduct baseline water quality sampling of all water sources within 1500 feet of HF 7 days prior to activity	Water quality monitoring must be conducted at 6 months, 18 months, and 30 months following HVHF	Operators must submit self-certification demonstrating compliance with the Water Use act. They must also submit a water source management plan	Illinois Administrative Code, Title 62, Chapter 1, Part 240
Kentucky	Baseline water quality testing must be done 20 days prior to a deep horizontal HVHF	Water testing from same source must be taken 3 and 6 months following HVHF	None	Kentucky House Bill 386, December 16, 2015.
Louisiana	None	None	Surface water use encouraged, applications involve assessment of environmental impacts of water use. Water sources and volumes must be reported for wells that are hydraulically fractured.	Louisiana Admin. Code tit. 43, pt. XIX § 118 (2011). October 20, 2011

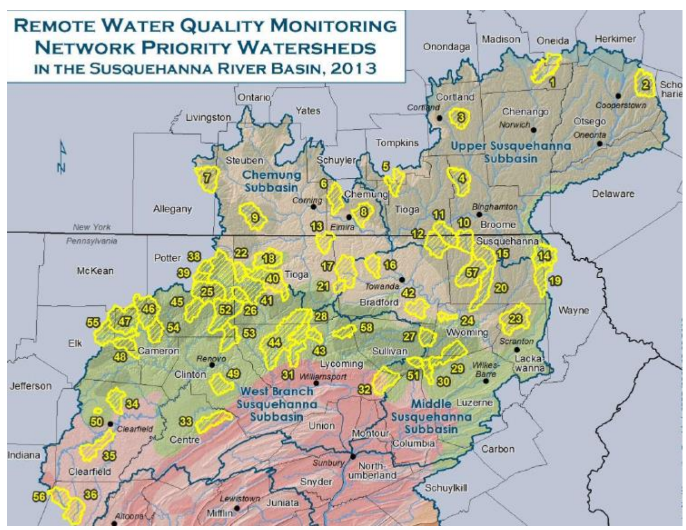
State	Baseline Water Quality	Long-Term Groundwater Monitoring	Water Source Analysis	Regulatory Code
Michigan	Requires baseline sampling from all water source wells within ¼ mile of the HVHF	None	Permittees must request a large volume water withdrawal prior to HF	Michigan Administrative Rules, Part 615, Section 324. March 11, 2015.
Nebraska	Requires baseline sampling of at least two freshwater sources within one mile of the well.	None	None	Nebraska L.B. 877 (Proposed Legislation).
Nevada	Requires baseline sampling from the four closest available water sources within a year prior to HF.	Water quality monitoring must be conducted at 6-12 months and 60-72 months following HF.	None.	Nevada Regulatory Statute 522.119. 2013.
North Carolina	Requires baseline sampling from all water source wells within ½ mile of the well at least 30 days before HF.	Water quality monitoring must be conducted at 6, 12, 18, and 24 months following HF.	None	North Carolina S.L. 2014-4. April 2014.
North Dakota	Requires baseline sampling of the two nearest freshwater sources within one mile of well.	None	None	North Dakota Century Code; Chapter 38, Section IV.
Pennsylvania	Requires operator to characterize the baseline of water quality within 1,000 feet of well.	Specific monitoring not required, but operators are held liable for any water pollution within 1,000 feet of the well within a 6-month period after conducting HF.	None	58 Pa. Cons. Stat. § 3222. April 14, 2012
Virginia	Operator provided access to sample private water wells within 750 feet of operation. Proposed regulation to extend radius to ¼ mile	Proposed legislation to require water testing of wells within 6-12 months after hydraulic fracturing	None	Virginia Administrative Code 4VAC25-150

State	Baseline Water Quality	Long-Term Groundwater Monitoring	Water Source Analysis	Regulatory Code
Wyoming	Yes, developer required to submit a baseline sampling analysis and monitoring plan as part of APD. Sampling required for up to 4 wells within a ½ mile of well.	Water quality monitoring must be conducted between 12-24 months and 24 months after last test.	None	Wyoming Wyo. Code Rules and Regs. Oil Gen. § 45. October 17, 2010

Susquehanna River Basin's Comprehensive Regulatory Oversight of Water Acquisition for Oil and Natural Gas Industry

The Susquehanna River Basin, located in the Marcellus Shale Region of the northeast United States, is an example of efforts to regulate water acquisition associated with unconventional oil and natural gas operations. The region has seen an increase in hydraulic fracturing in the last decade. The Susquehanna River Basin Commission (SRBC), the regulatory authority charged with overseeing water use in the basin, developed new regulations in response to the increased water demand associated with hydraulic fracturing. The primary purpose of the SRBC is to oversee water quantity, but since impacts to water quantity have a direct relationship with water quality, the new regulations also address water quality, particularly with regard to support of ecosystem services.

- In 2008 the SRBC adopted a "Gallon One" rule, meaning that SRBC review and approval would be required for the first gallon of water withdrawn, lowering the existing regulatory threshold in order to review a greater number of proposed uses. An "approval-by-rule" process is implemented on a drill pad basis and requires that all water consumed by industry comes from an approved source.
- The SRBC implemented a Low Flow Protection Policy in 2012 which specifies minimum stream flow rates under which withdrawal must cease.
- In 2010 the SRBC adopted the Remote Quality Monitoring Network to collect real-time continuous water quality data, with supplement water quality samples collected quarterly. Under certain conditions the SRBC also validates the water withdrawal sites by collecting and analyzing water quality samples.



- The SRBC implemented a robust Compliance Program, with enhanced communications systems and computerized systems to help inspectors collect and analyze large volumes of data.

In April 2016 the SRBC released a report analyzing the efficacy of the regulations and policies and to determine if adverse impacts on water resources have occurred. The report finds that "the basin's water resources are sufficient in magnitude to accommodate the water demands of the industry concurrently with other water users." The report found that the amount of water used consumptively by the oil and natural gas industry was comparable to other water users, such as manufacturing and recreation, in the Basin. Electric power generators on average used 10 times more water per day than the oil and natural gas industry. Moreover, the monitoring programs have not detected impacts on the Basin's water quality. (SRBC 2016).

SECTION 5

Chemical Mixing

The chemical mixing chapter of the EPA Draft Assessment focuses on the mechanisms by which chemicals could spill during hydraulic fracturing operations, followed by chemical fate and transport through the environment, and ultimately chemical toxicity.

The process of hydraulic fracturing consists of injecting a fluid slurry into a well over a short period of time (typically less than an hour per stage) at pressures sufficient to fracture the rocks of the target shale formation. The injected fluid consists of three parts, the base fluid, the proppants and the chemical additives. Water (base fluid) and small granular solids (proppants) make up approximately 99% or more of the fluid injected in a typical hydraulic fracturing event. Less than 1% of fracturing fluid are chemical additives.

Each chemical additive performs a specific purpose; biocides control bacteria, acids reduce clogging in the well bore, gelling agents and cross-linkers increase viscosity and ensure that proppants are delivered to the fracture, corrosion inhibitors reduce corrosion and pH controls stabilize pH, among others. Chemical additives comprise only a small fraction of the fluid injected into a well, while millions of gallons of base fluid (typically water) may be injected to fracture each well. Chemicals are mixed into the fracturing fluid on site and the fracturing fluid is then pumped into the well. As a result, chemicals and fracturing fluids have the potential to leak or spill at the surface; recognizing that if there is a leak or spill it can be contained so it only has the potential to migrate in the environment. Even if a chemical is released in the environment, it can be contained in shallow soils; again only having the potential to impact drinking water sources.

5.1 SUMMARY OF EPA FINDINGS

The EPA Draft Assessment identifies the three primary times during which chemicals can spill to the ground surface as (1) on-site chemical storage, (2) chemical mixing, and (3) chemical pumping into the target well. The EPA Draft Assessment addresses various situations that could result in a spill during these processes. The primary causes are equipment failure, container integrity failure, and human error, causing 34%, 11% and 25% of spills, respectively. The EPA Draft Assessment 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.

The EPA does not explicitly consider regulatory requirements for the issues noted, stating: “Hydraulic fracturing operating companies themselves may develop and implement spill prevention and containment procedures. It was beyond the scope of this assessment to evaluate the efficacy of the practices in these documents or the extent to which they are implemented” (EPA 2015a). The EPA’s choice to not highlight industry practices is a significant omission because there are a large number of operational and management practices routinely utilized by industry, as well as regulations, to minimize risks associated with chemical handling and use. This portion of the oil and natural gas cycle has significant regulatory controls. These are summarized in Section 5.3 below.

5.2 SUMMARY OF SAB COMMENTS

The SAB’s primary concern with discussion of chemical mixing and the associated spill risk is that the data set the EPA relies on – Pennsylvania and Colorado – is too limited, stating that “while the SAB recognizes that the states of Pennsylvania and Colorado likely have the most complete datasets on this topic that the EPA could access, the SAB finds that the draft Assessment Report’s analysis of spill data cannot confidently be extrapolated across the entire United States.” In addition, the SAB requests a description of the current state of reporting on spills from hydraulic fracturing. Finally, the SAB suggests inclusion of additional information about the standard practices that are applied to chemical mixing that reduce spill potential (SAB 2016).

5.3 INDUSTRY PRACTICES AND REGULATORY PROGRAMS

The SAB focuses on deficiencies in the EPA Draft Assessment’s spill data, but as described below, the Draft Assessment does *not* rely on just Colorado and Pennsylvania for all spill-related analysis, only for the analysis of spill *frequency.* When analyzing other spill characteristics, including cause, volume released, volume recovered, media, and other factors, EPA relies on a much larger data set, including the ten states with the greatest rates of hydraulic fracturing between 2009 and 2010: Arkansas, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming (EPA 2015b). The Pennsylvania and Colorado state databases were the only to include spill frequency; although only two states, these have the second and third highest number of hydraulic fracture jobs (after Texas) and therefore are still broadly representative of national frequency.

As identified by the EPA, it is possible that spills may occur during the hydraulic fracturing process. However, there is a large array of industry standards and operational practices to minimize spills and ensure that they do not impact water resources. Additional detail is provided in the following subsections. The majority of the spills do not reach water resources; these spills may impact soil but are generally contained and removed before they are able to travel to and impact groundwater and surface water. Only 8% of the spills analyzed reached surface waters, and no spills impacted groundwater (EPA 2015a). Spills are captured as much as possible as part of spill response activities, and typically further remediation is conducted to limit impacts to water resources. In addition, the industry is continually evolving and improving. Spills rates have decreased dramatically over the last several decades (API 2009). In addition, industry is starting to utilize “greener” chemicals, keep more robust data on chemical use and spills, and report this information to the public. These trends are described in the following subsections.

5.3.1 Explanation of EPA's Spill Frequency Data Set

The SAB comments that the EPAs analysis is too limited in relying on data from only Pennsylvania and Colorado. These states have the second and third largest number of hydraulic fracture jobs (after Texas), and therefore the EPA database encompasses a large percentage of potential spills associated with hydraulic fracturing. In addition, it is critical to note that EPA does not rely on this data set for all spill related analysis, but only for the analysis of spill *frequency.* When analyzing other spill characteristics, including cause, volume released, volume recovered, media, and other factors, EPA relies on a much larger data set, including the ten states with the greatest rates of hydraulic fracturing between 2009 and 2010: Arkansas, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming (EPA 2015b). The Pennsylvania and Colorado state databases include the only data available regarding spill frequency.

With regard to spill frequency, EPA reviewed spill rate data from a wide set of public and private data, but relied solely upon two data sources to develop their spill frequency estimate – the Pennsylvania Department of Environmental Protection (PADEP) Oil and Gas Compliance Report Database and the Colorado Oil and Gas Conservation Commission (COGCC) database. EPA relied exclusively on data from Colorado and Pennsylvania for two reasons: 1) the COGCC spill database offered the most detail and ability to search their spill reports to determine if the spill was caused by hydraulic fracturing operations; and, 2) the PADEP undertook a comprehensive study such that Pennsylvania had the most transparency in their publicly available environmental compliance/violation databases. In EPA's *Review of State and Industry Spill Data; Characterization of Hydraulic Fracturing-Related Spills* (EPA 2015a), the Agency explains further that the PADEP and COGCC sources offer the best set of data for linking spills to hydraulic fracturing. EPA references the COGCC for having reporting requirements that call for a description on the origin of the spill, thus allowing analyst to determine if a spill was caused by hydraulic fracturing operations rather than oil and natural gas operations at large (EPA 2015b). This is not possible with the other state databases.

It should be noted that by incorporating the findings of the PADEP Independent Study, EPA was relying upon two different criteria for defining and estimating the frequency of a spill due to hydraulic fracturing operations, hence the wide variation in EPA's estimate (i.e. 0.4 to 12.2 spills per 100 wells fractured). While data for hydraulic fracture-related spill frequency in Texas, the state where the most hydraulic fracturing occurs, is not included in the data set, Colorado and Pennsylvania are the states with the second and third most hydraulic fracturing.

In determining other criteria for spill characterization, including volume, timing, cause, and other factors, EPA incorporated a large, comprehensive data set from over a dozen public and private sources. The ten states with the most hydraulic fracturing activity were analyzed, including Arkansas, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. State spill data sources were identified for all states except North Dakota, which was not publically available at the time that the analysis was performed. Therefore, the EPA Draft Assessment does not rely on two states for all the spill analysis; it relies on the 10 states that encompass most of the hydraulic fracturing in the country, and is therefore robust for the conclusions that EPA draws from it.

5.3.2 Operational Practices

A large number of management practices are used by industry to help reduce potential impacts associated with chemical spills. While the EPA acknowledges that such best practices exist, it explicitly states that it does not fully consider them in the spill analysis. The following sections summarize the wide array of practices that are utilized to address impacts associated with hydraulic fracturing spills in response to the concern expressed in the SAB comments.

5.3.2.1 Chemical Transport

Department of Transportation (DOT) regulations govern the transport of chemicals used in hydraulic fracturing. For example, acid transport trailers and fracture tanks must be lined with chemical-resistant coating designed to prevent leakage and must meet applicable DOT regulatory standards (pursuant to 40 CFR 173) designed to prevent or reduce spills. In the API Guidance Documents RP 51R Environmental Protection for Onshore Oil and Gas Production Operations and Leases and RP 100-2 Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing, (API 2010, API 2015b), API emphasizes the importance of ensuring that materials and chemicals are transported to and from the site of hydraulic fracturing operations in accordance with federal, state and local regulations, and in a manner designed to prevent spillage and minimize air and noise impacts. In addition, it is standard industry practice and a DOT requirement that all transport vehicles display proper placards and other markings (API 2010, API 2015b).

In addition, fracturing equipment transported by trucks on the highway, especially chemical additive containers, must be checked for leaks prior to departure from the storage yard. Prior to departure tankers carrying fracturing fluids are checked to ensure discharge valves are closed and leak-free, and open-ended lines are securely capped. Containers storing proppants are inspected to ensure materials cannot be impacted by the wind while or otherwise leak during transport. These safety precautions significantly help reduce the potential for a leak or spill while transporting hydraulic fracturing fluids (API 2010, API 2015b).

5.3.2.2 On-Site Chemical Handling and Storage

API Guidance Document RP 100-3 (API 2015b) also notes the importance of properly managing on-site fluids before, during, and after the fracturing process. Chemicals used for hydraulic fracturing are most commonly stored on-site in tanks or are containerized for transport and after delivery. Tanks must also meet federal and state regulations for integrity. Certain chemical additives require specialized containment with additional spill prevention measures. For example, industry has developed special guidance on safe storage and handling of methanol. In addition, documentation is kept on all materials placed in surface impoundments (API 2015b). In general, industry practice is to blend chemicals only when needed to minimize the time stored. Any unused chemicals are removed from site upon completion of the job.

For states that allow the use of surface impoundments, including those used for temporarily storing fracture fluids, impoundments must be constructed in accordance with existing state and federal regulations. For example, in California the SB 4 implementing regulations prohibit the storage of well stimulation fluids in unlined impoundments. In some states, an impoundment requires prior authorization from one or more regulatory agencies and in others a separate permit is required specifically for the impoundment’s functional use. Industry standards and regulations for wastewater impoundments are addressed in Section 5.3.2.1 (API 2015b).

5.3.2.3 Operations

API standards (API 2015b) specify that operators evaluate equipment to verify that equipment is designed for well fluid conditions, pressures, and the abrasion created by fracturing fluids and proppants delivered during hydraulic fracturing. Equipment is configured on-site to minimize spill risks associated with hydraulic fracturing. Hydraulic fracturing equipment, including blenders and pumpers, are regularly inspected and monitored for leaks and loss of integrity, before, during, and after hydraulic fracturing operations to minimize and mitigate risks associated with equipment leaks and spills. Prior to conducting hydraulic fracturing operations, piping is pressure tested and subsequently the hydraulic fracturing operations are monitoring to ensure that pressures do not exceed the pressure rating of the equipment and of the piping (API 2015b).

5.3.2.4 Planning

Planning is a key factor in spill incident prevention. First, the well pad is graded and prepared taking into consideration the locations of surface waters and flood zones. Second, the facility design is reviewed to determine where the potential for spills exists. Information on prior spill incidents is included in the review to assess areas where changes in equipment or practices may be needed. The site layout may be modified to reduce spill potential. In addition, operators examine field drainage patterns and install containment, BMPs, barriers, or response equipment as deemed appropriate. The operator considers reducing spill related risks by sloping the well location away from surface water locations, positioning absorbent pads between drill sites and surface waters, or installing perimeter trenching systems and catchments to contain and collect any spilled fluids. Fluid management plans are becoming more standard within the industry. Such plans include the site layout, locations and capacity of all storage tanks or impoundments, access restrictions and physical boundaries, and descriptions of where and how liners and other secondary containment devices will be installed (API 2015b).

After the site plan is established, the job planning process proceeds, including a contingency plan for proper material management for unforeseen circumstances that may delay the fracture operations. For example, the job plan includes management of fluids that remain in lines or tanks after the fracturing has been completed. Employees are trained on procedures for collecting fluids remaining in lines, including the use of collection buckets, catch basins, or vacuum trucks. The planning process also considers the use of alarms, automatic shutdown equipment, or fail-safe equipment to prevent, control, or minimize potential spills resulting from equipment failure or human error.

Spill Prevention, Control, and Countermeasure Plans (SPCC) are required on site to provide standard operating procedures to prevent spills, identify control measures (such as secondary containment) to prevent spills from impacting water resources, and identify countermeasures to contain, cleanup, and mitigate the effects of a spill. While these plans are normally targeting toward oil spills, they are also applied to any chemical storage and handling to help prevent spills and resulting impacts to water resources. All on-site employees are trained on the SPCC Plan. In the event of a spill, the source is controlled as quickly as possible, and the spill is confined with walls/dikes around tanks, absorbent pads, temporary booms, or special chemicals to bio-degrade the sampled fluids, among many other options (API 2015b).

5.3.2.5 Training

API emphasizes the importance of employee training and awareness to help reduce the risk of impacting water resources with leaks or spills. In addition to the aforementioned SPCC Plan and trainings, the trend is that service companies are more transparently educating operators (clients) about the various fluids and additives that maybe used as a part of a fracture fluid. An essential first step is providing operators with the Safety Data Sheets (SDS) for products used in their wells. Service companies work with operators for optimal fracturing designs, which include a full complement of suggested fluid alternatives, along with the potential environmental impacts and costs associated with each alternative. Training and procedures for operating and handling for each chemical utilized in the fracturing process improve responsiveness to potential surface incidents. As part of the overall operation plan, service companies now provide operating and handling procedures for each chemical utilized, including those for emergencies and disposal (API 2015b). On-site personal are properly trained in how to test and inspect equipment, hoses and connections for integrity prior to and after hydraulic fracturing operations.

Prior to hydraulic fracturing operations, industry standards specify that both operators and service companies conduct a job site safety meeting with all personnel who will be working on-site. During the site meeting the following topics are generally addressed:

- SDSs: Discussion about and location of the SDS information for each hazardous chemical present on-site. The SDS must be readily accessible for each chemical on site. The safety meeting discusses emergency and first aid procedures for each chemical;
- SPCC, as described above; and
- Reporting: Employees are trained about the procedures to fully and properly report spills or leaks.

5.3.3 Industry Trends

5.3.3.1 Decreasing Spill Frequency

Spills rates across the oil and natural gas industry have been decreasing over the last several decades (API 2009). The implementation of prevention-oriented regulations and voluntary industry initiatives, as described in Section 5.3.2, has had the combined effect of reducing spillage dramatically.

5.3.3.2 Pipeline Improvements

Corrosion resistant and leak-proof connections as well as monitoring methods are continually being developed, evaluated and field tested to help reduce the likelihood and extent of equipment leaks and spills. These evaluations have included the pipeline materials, the longevity and design life, and the most effective sizes for field use.

In addition, there has been a trend towards relying on temporary surface pipelines to transport fluids during operations. Temporary pipelines are typically lie-flat surface hoses. Technological advances, including higher pressure ratings, stronger connections, and abrasion resistance, have allowed the proliferation of this effective, low cost, and flexible way to move fluids, reducing spill risks associated with truck transport (CH2M Hill 2015).

5.3.3.3 Chemical Selection and Green Chemicals

A key component of hydraulic fracturing is selection of chemical additives to achieve the technical and environmental goals for the job. Water and small granular solids such as sands and ceramics, called proppants, typically make up more than 99% of the fluid used in a typical hydraulic fracturing operation. Figure 5-1 illustrates the typical fluid used in hydraulic fracturing (GWPC 2009). The gray wedges depict those chemicals that are used in both hydraulic fracturing and conventional oil and natural gas operations, representing 50% of the chemicals injected. Only 0.246% of the total fluids injected into a well during hydraulic fracturing are unique to the process of hydraulic fracturing.

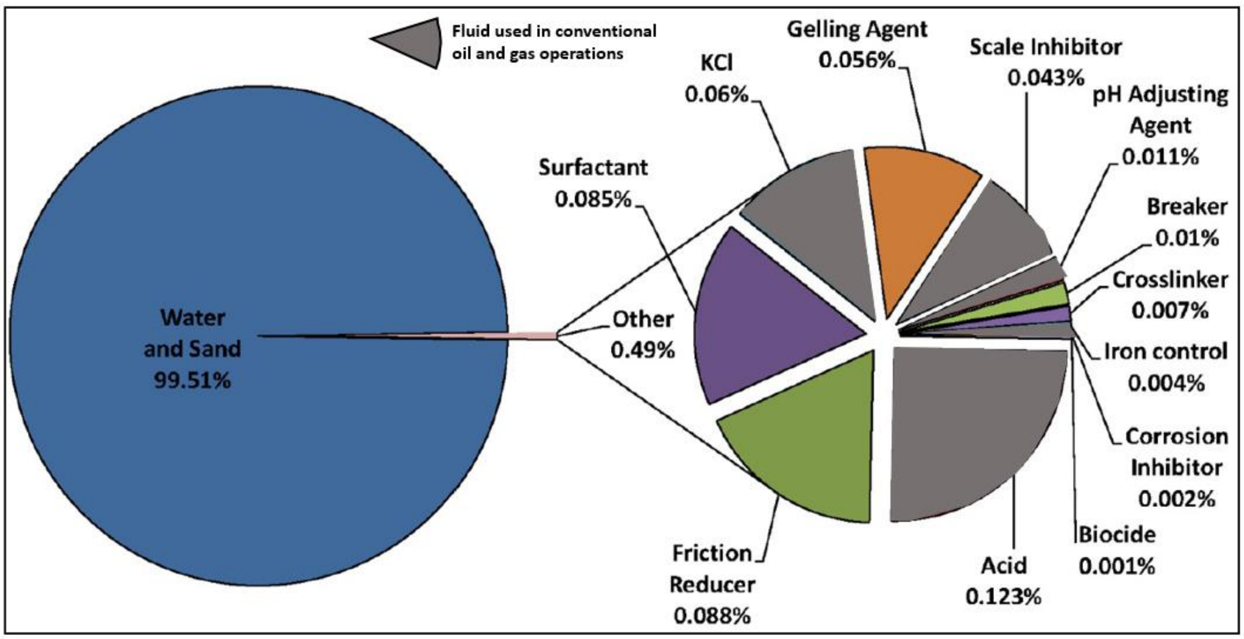


Figure 5-1. Composition of Typical Fracturing Fluid

Across the oil and natural gas industry there is a trend towards using “greener” chemicals (those with lower toxicity or of food grade) during hydraulic fracturing. Seeking to identify and use chemicals with reduced toxicity and less potential impact of chemical additives used for hydraulic fracturing is a key area of innovation in the industry. In RP 100-2, API urges operators to regularly evaluate new products that provide environmental protection opportunities while meeting operational goals. As noted in the draft EPA report, some of these chemicals include the following:

- A renewable citrus-based replacement for conventional surfactants;
- A cross-linked gel system comprised of chemicals designated as safe food additives by the U.S. Food and Drug Administration;
- A polymer-free gel additive;
- A dry, hydrocarbon-free powder to replace liquid gel concentrate;
- Biodegradable polymers;
- The use of ultraviolet light to control bacteria; and
- new chelating agents that reduce the use of strong acids

As an example of the trend towards greener chemicals, one large service provider developed a chemical mixture known as CleanStim, which contains chemicals approved for use in the food industry, listed in Table 5-1, below.

Table 5-1. Components of CleanStim Fracturing Fluid

Generic Constituent Name	Common Use	Hazardous as Appears on SDS
Enzyme	Soybean Paste, Fruit Juices and Nectars, Laundry Detergent, Dishwasher Detergent, Toilet Cleaner, Industrial Pulp and Paper Processing Aid	Yes
Ethoxylated Sugar-Based Fatty Acid Ester	Synthetic Food Flavoring Substance, Natural Baby Wipes, Baby Wash and Shampoo	No
Inorganic Acid	Cheese, Alcoholic Beverages, Wheel Cleaner, Rust/ Dissolver, Dishwashing Detergent	Yes
Inorganic Salt	Food Starch - Modified, Water Clarifier, Fish Tank Water Treatment	Yes
Maltodextrin	Sweetener, Glaze and Icing Sugar, Coconut Milk and Coconut Cream, Shower Gel	No
Organic Acid	Fruit Juice, Dishwasher Cleaner, All-Purpose Cleaner, Hand Soap	Yes
Organic Ester	Liquid Egg Products, Food Resinous and Polymeric Coatings, Hairspray	Yes
Partially Hydrogenated Vegetable Oil	Confectionary Chocolate Coating, Hair Detangler, Body Lotion, Lip Liner, Soap, Lotion, Cream and Other Skin Care Formulations	No
Polysaccharide Polymer	Canned Fish, Processed Cheese, Dairy-Based Desserts and Drinks, Beer, Toothpaste	Yes
Sulfonated Alcohol	Egg White Solids, Marshmallows, Dishwashing Liquid, Home Dilutable Cleaner, Shampoo, Acne Scrub, Shaving Cream, Liquid Hand Soap	Yes

Source: Halliburton 2016.

Many service operators are focused on using only chemicals that are approved by the EPA's Design for the Environment program, which evaluates consumer products such as laundry detergents and window cleaners. These biodegradable chemicals would be easier to clean up in the event of a spill, and have a smaller ecological impact (CH2M Hill 2015).

Similarly, many service providers are developing hazard ranking systems for evaluating the chemicals used in their hydraulic fracturing operations. Typical chemical ranking criteria include mobility, persistence, biodegradation, bioaccumulation, toxicity, and hazard characteristics. These internal ranking systems are used in helping service providers select their suite of chemicals.

Green Chemistry principles attempt to maintain an equivalent function while using less hazardous chemicals and smaller amounts of hazardous chemicals. It may be possible to forego or reduce the use of the most hazardous chemicals without losing much functionality. Care must be exercised in substituting chemicals to ensure that there are not unanticipated consequences that then require addition chemicals to address. For these reasons, the American Chemical Society currently sponsors a Green Chemistry Roundtable on the topic of hydraulic fracturing, thus placing this industry trend within national and global efforts to move towards Green Chemistry for all chemical use, including that for hydraulic fracturing (CCST 2015).

Finally, the EPA Draft Assessment identified over one thousand chemicals that have been used in different hydraulic fracturing operations, while only approximately 30 that are regularly used in all hydraulic fracturing jobs. This list does not necessarily reflect the most recent industry data and practices. EPA used ten sources to develop its list of 1,076 chemicals used in fracturing fluid. One source included the chemicals reported by nine fracturing service companies between the years of 2005 and 2010 – certainly an out-of-date reference for 2015 activity. Much has changed in the industry in the five years since the study was initiated. Oil and natural gas companies, hydraulic fracturing service providers and non-profit organizations are working on strategies to reduce the number and volume of chemicals used in hydraulic fracturing. By reducing the number of chemicals and preferring those with better characterized properties, both the uncertainly and the potential for adverse impacts are reduced significantly.

5.3.3.4 Chemical Disclosure and Transparency

States where hydraulic fracturing occurs have enacted regulations for the disclosure of chemicals used in the hydraulic fracturing process. These state-specific regulations are discussed in greater detail in the Regulatory Section, 3.2.1. Most states require disclosure through the FracFocus (www.fracfocus.org) chemical registry, a database and website initiated by the Groundwater Protection Council (GWPC) and the IOGCC. A total of 29 states have chemical disclosure regulations, and of these 23 currently use FracFocus for that purpose, and 2 more are considering using FracFocus. Of the 2 states with pending chemical disclosure regulations, both are planning on using FracFocus. FracFocus continues to be an "evergreen" tool, adapting to regulatory requests for search capabilities and other requirements to address external stakeholder requests. In general, public disclosure via sustainability and social responsibility reporting and company websites are becoming increasingly commonplace.

In its *Policy Position of API on Chemical Disclosure for Hydraulic Fracturing Operations*, API supports and promotes full disclosure of chemical ingredients intentionally added to hydraulic fracturing fluids, with recognition of claims for protection of intellectual property rights provided for under applicable state or federal laws and regulations. API encourages regulatory agencies with primary jurisdiction over oil and natural gas operations to incorporate use of the FracFocus Chemical Disclosure Registry (Fracfocus.org) in their regulatory frameworks.

States lead the oversight and management of oil and natural gas operations, including hydraulic fracturing operations and chemical disclosure. States are best positioned to meet local needs and conditions and to be the most responsive to protection of human health and the environment. Imposition of additional Federal requirements for hydraulic fracturing chemical disclosure is therefore redundant and unnecessary. API continues to support equitable treatment of the oil and natural gas industry as compared to other industries that also relay on trade secret protections.

SECTION 6

Well Injection

Hydraulic fracturing creates conductive fractures in reservoir rocks in order to enhance the flow of fluids, including water, oil, or natural gas to the well. In the hydraulic fracturing process, the operator or service company pumps fracturing fluids into a discrete zone of the well until the fluid pressure is sufficient to fracture the rock. The fluids flow into the fractures depositing "proppant" in the fractures to keep them open during subsequent production. The spent hydraulic fracturing fluid generally flows back into the well after the fracturing operation. Fluids produced from the well gradually changes over time from spent hydraulic fracturing fluids to "production" fluids (oil, natural gas, and produced water). The transition at which the composition of fluids change from flowback to production is not precisely defined.

The well injection section of the EPA Draft Assessment addresses the step of the hydraulic fracturing process in which fracturing fluids are injected into a well at high pressures. It should be noted that the fracturing process does not require continuous high pressure injection into the subsurface, but instead occurs over a relatively short period of time -- approximately 1 hour per hydraulic fracturing stage. This critical distinction in the duration of increased pressure is important to constrain the fate of chemicals in the subsurface environment for only a relatively brief time (approximately one hour per stage) of applied pressure for hydraulic fracturing. During the increased pressure, hydraulic fracturing fluids are injected into the newly-formed fractures. Overall pressures in the reservoir increase. When injection is stopped, the decreasing pressures in the reservoir "push" or "lift" the oil, natural gas and water into the well and up to the surface.

The pressurized fluids fracture the shale formation and the sand (proppant) in the fluid serves to prop the fractures open, allowing oil, natural gas and water in the source shale to move more freely into the well. Hydraulic fracturing is a well completion process, and occurs after drilling a well. However, the EPA Draft Assessment also addresses well drilling.

Drilling and completing a well consists of many sequential activities, which are listed below in the order they typically occur:

- Building the well pad and installing fluid handling equipment;
- Setting up the drilling rig and ancillary equipment and testing all equipment;
- Drilling the hole;
- Running formation evaluation logs and other instruments down the well;
- Running casing (steel pipe) to line the wellbore;
- Cementing the casing;
- Removing the drilling rig and ancillary equipment;
- Logging the casing to ensure bonding of cement to the formation and casing;
- Perforating the casing;
- Stimulating the well;
- Installing surface production equipment;
- Beginning production of the well;
- Monitoring well performance and integrity; and

- Reclaiming the parts of the drilling location that are no longer needed and removing equipment no longer used.

6.1 SUMMARY OF EPA FINDINGS

The EPA identifies two primary mechanisms through which the injection phase of a hydraulic fracturing job could potentially impact drinking water resources: (1) movement of fluids outside of the production well due to compromised well integrity, and (2) unintended migration of fluids through the subsurface geology into drinking water resources. The EPA Draft Assessment identifies a number of potential scenarios where well integrity could be diminished, primarily due to casing or cementing failures. In addition, the EPA identifies potential impacts associated with well communication, highlighting the importance of well placement. Finally, the EPA Draft Assessment addresses the potential for fluid migration through unintended fractures.

6.2 SUMMARY OF SAB COMMENTS

One of the SAB's primary concerns with the well injection analysis presented in EPA's Draft Assessment is the lack of information about industry standards and best management practices that are relied upon to ensure well integrity and minimize potential environmental impacts. The SAB recommends that this discussion include an examination of well design principles, including drilling, casing, and cementing, as well as testing, and monitoring. The SAB also suggests providing a description of well spacing requirements and well abandonment practices in order to address concerns related to well communication. Finally, the SAB recommends that the EPA Draft Assessment "summarize improvements, changes or accomplishments that have occurred since 2012 in hydraulic fracturing operations related to [hydraulic fracturing]. Since 2012, many significant technological and regulatory oversight improvements have occurred related to well construction, well integrity, well injection, and other aspects of the [process]. These improvements should be examined in the draft Assessment Report." (SAB 2016).

6.3 INDUSTRY PRACTICES AND REGULATORY PROGRAMS

As accurately noted by the SAB, a number of industry standards and industry practices are related to well injection regarding how well integrity can be maintained. Methods to evaluate and improve well integrity continue to evolve, such as with the development of new cementing technologies, as well as the introduction of new monitoring techniques to ensure zonal isolation is maintained, described below.

The hydraulic fracturing process at one well takes approximately one hour per stage, and several stages may be performed over the course of one to several days. As such, a well is only subject to significantly increased pressures for a short duration. Most of the potential impacts associated with well integrity and/or fluid migration would only occur during this short timeframe of applied pressure. Once the completed well is brought on to production, the well is subjected to a relative vacuum force to extract water and petroleum fluids, and the sense of fluid motion is towards the well; the opposite direction as during hydraulic fracturing.

API submitted comments in response to the EPA Draft Report which summarized the state of the science with respect to the potential for injection associated with hydraulic fracturing to impact water quality, and we refer to those comments for additional information related to field data collection and modeling studies, and the finding that impacts to surface water quality from injection into deep shale formations is theoretical at best.

6.3.1 Operational Practices and Industry Standards

In addition to robust state regulation and enforcement, the oil and natural gas industry has many standard operating procedures and practices to protect human health and the environment during injection. The following sections discuss various operating practices implemented throughout the oil and natural gas industry as they relate to well design, well drilling, well stimulation (hydraulic fracturing), and maintaining well integrity.

As described in EPA's Draft Assessment, hydraulic fracturing has been conducted by operators to complete oil and natural gas production wells for nearly six decades; as such, the industry has developed designs and techniques for casing, well drilling, and cementing, to protect the wellbore during high pressure injection activities, restrict fluids to the intended zone, and enable hydrocarbon production. API has developed a series of publications, technical standards and guidance documents for every aspect of the well drilling and completion process enabling oil and natural gas exploration and development to be carried out in a manner to safeguard human health and the environment, to provide appropriate safety guidance and training, and to comply with local, state and federal regulatory requirements. API has published over 600 guidance documents, 275 of which address onshore exploration and production. These detail-oriented guidance documents cover a vast array of material from selecting and testing cements, to installing casing and designing hydraulic fracturing events. API's guidance documents are widely relied upon throughout the oil and natural gas industry. Selected guidance documents applicable to well drilling, casing, and cementing include:

- 11D-1 – Packers and Bridge Plugs (3rd Edition published April 2015)
- 5C-1 - Recommended Practice for Care and Use of Casing Tubing (18th Edition published May 1999, reaffirmed May 2015)
- 5CT – Specification for Casing and Tubing (9th Edition published July 2011)
- 10A – Specification on Cements and Materials for Well Cementing (24th Edition published June 2011)
- 10B-2 – Recommended Practice for Testing Well Cements (2nd Edition published April 2013)
- 10D-2 – Recommended Practice for Centralizer Placement and Stop-Collar Testing (1st Edition published August 2004, reaffirmed April 2015)
- 65-2 – Isolating Potential Flow Zones During Well Construction (2nd Edition published December 2010)
- 51R – Environmental Protection for Onshore Oil and Gas Production, Operations and Leases

Wells are drilled in the same manner, regardless of whether they will be completed using hydraulic fracturing. API produced a guidance document in 2009, revised in 2015 (RP 100-1) that addresses design and operational practices for well construction and integrity specifically for wells that will be hydraulically fractured. As stated within this guidance document, "maintaining well integrity is a key design principle and design feature of all oil and natural gas production wells. Maintaining well integrity is essential for the two following reasons: 1) to isolate the internal conduit of the well from the surface and subsurface environment. This is critical in protecting the environment, including the groundwater, and in enabling well drilling and production; and 2) to isolate and contain the well's produced fluid to a production conduit within the well." Therefore, the primary purpose of this document is to ensure that groundwater aquifers and the environment are protected. The primary means of protecting underground sources of drinking water is by casing the well with a steel pipe and cementing it into place. Several layers of steel casings and cement sheaths are sequentially installed so that the produced fluids travel directly from the producing formation, through the well conduit, and to the surface oil and natural gas processing equipment. The purpose of cementing the casing is to provide zonal isolation between different formations, including full isolation of underground sources of drinking water and to provide structural support of the well. Cement is fundamental in maintaining integrity throughout the life of the well and part of corrosion protection for the steel casing.

Operators design and plan the casing and construction of each well and utilize a variety of procedures and diagnostic tools, as appropriate, to assess well casing integrity prior to conducting hydraulic fracturing operations. These procedures and diagnostic tools include:

- determining the proper chemical composition and mechanical properties of the steel casing and cement to be used and verifying proper cement density and cement additive control;
- centralizing of the well casing;
- using specialized equipment to evenly distribute the cement between the casing and the wellbore;
- varying pump rates to establish the optimal fluid flow during cementation (installation);
- monitoring pump pressures and fluid returns during the cementing process to verify adequate coverage of the cement throughout the targeted area, including coverage of hydrocarbon strata and zones containing drinking water aquifers;
- performing casing pressure tests after cementation; and
- using sonic and ultrasonic cement bond evaluation logs.

Because of differences in geologic and other conditions at well locations, casing programs and testing equipment, tools and procedures must be customized for each area. Such differences are taken into account by both well operators and state regulatory authorities in determining local regulations and permit requirements. Certain equipment, tools, or procedures that may be appropriate in one area may not be appropriate in other areas.

Table 6-1, below, provides a list of industry planning and operational practices for well drilling, casing, and cementing focusing on those steps that are most crucial for protecting underground sources of drinking water.

Catalyst ENVIRONMENTAL SOLUTIONS

Table 6-1. Industry Well Drilling and Stimulation Standards to Reduce Potential Impacts on Water Resources

Well Injection Stages	Industry Planning/Operational Practice	Benefit
Well planning	Prior to drilling a well planned for hydraulic fracturing, the completion engineer should communicate with the drilling engineer so that well can be designed to withstand the proposed completion activity. Have a complete drilling program and preliminary completion design prior to starting a well.	Proper planning enables the various components needed for well integrity.
	Locate groundwater sources, surface water sources and nearby water wells. Gather and review offset well information within the calculated area of investigation.	Assess and mitigate potential risks prior to drilling and completion activities.
Wellbore drilling	Must use air, freshwater, freshwater-based, or another drilling fluid acceptable to the regulator during drilling until groundwater resources have been isolated with casings and cementing.	Protection of drinking water resources during drilling.
	Prior to drilling, the following must be pressure tested: blow-out preventer, casing string, stabbing valve, inside blow-out preventer, lower kelly valve, choke manifold, bleed-off and kill line.	Demonstrates that well components can perform up to their design operating pressures, thereby withstanding high pressure injections without damage.
Open hole well logging	Perform a variety of logging tests: • Gamma Ray testing to measure naturally occurring gamma radiation • Density tests – determine porosity of formation • Caliper – gathers diameter measurements • Resistivity	Helps determine geological characteristics of formations and design optimal cementing plan.
Casing	Must install steel casing that can withstand high pressures and elemental weathering.	Wellbore protection, avoid damage to well components, protection of drinking water resources.
	Well casing must have pressure rating that is at least 10% greater than maximum applied hydraulic fracturing pressure.	Wellbore protection, avoid damage to well components, protection of drinking water resources.
	Casing should be handled with thread protectors in place.	Protects the quality of casing prior to installation in wellbore.
	Casing that will be fractured should meet API standards Spec 5CT and 5B, which address casing design, manufacturing, testing, and transportation and include strict compression, tension, collapse, and	Provides performance, quality, and consistency in well casing.

	burst resistance requirements.	
	Joints should be threaded rather than welded.	Provides joint strength, prevent damage, or unanticipated leakage.
	Welding at casing bowls should be conducted in accordance with API welding procedures in Spec 6A.	Provides casing bowl strength, prevent damage, or unanticipated leakage.
	Threaded casing and tubing joint connection make-up and torque procedures should meet API specifications. Casing torque data must be recorded in the daily tour sheets for any casing or tubing strings that are primary or secondary barriers for hydraulic fracturing operations.	Complete record-keeping to confirm casing is completed according to standards and allow an operator to more quickly identify any abnormalities that require corrections.
	Install four layers of casing (conductor, surface, intermediate, production) and pressure test each layer as it is installed.	Provides four layers of protection, especially near groundwater resources up to ground surface.
	Determine depth of each casing and carefully document in drilling plan.	Confirming proper depths of casing provides isolation of groundwater resources.
Conductor Casing	Conductor casing (outermost layer) must be cemented to its full length. The drilled diameter of the bore hole must be at least 100 millimeters larger than the diameter of the conductor casing.	Maintains a stable well bore, prevents groundwater infiltration and keep the unconsolidated surface material in place during drilling operations.
Surface Casing	Surface casing is drilled with water-based drilling fluids because it passes through drinking water reservoirs and is drilled below USDW reservoir and cemented from bottom all the way to ground surface. Following these procedures, the casing is pressure tested. Surface casing depth should be a minimum of 50 feet below the base of groundwater.	Provides protection of groundwater resources and confirms casing integrity meets well design requirements and can withstand pressures exerted during hydraulic fracturing.
	Avoid use of fillers or additives that reduce the compressive strength of surface casing cement below the minimum required strength.	Enables strength of casing to withstand high pressures; avoid damage to the wellbore, prevent leaks
	The required cement volume must be based on calculated hole-size measurements plus a minimum of 50% excess cement, or hole-size measurements, taken from a caliper log plus a minimum of 20% excess cement volume. Surface casing should be fully cemented back to surface.	Provides protection of groundwater resources and confirms casing integrity meets well design requirements and can withstand pressures exerted during hydraulic fracturing
Intermediate	Must be cemented at least 200 feet from (1) the base or (2) any	Isolates subsurface formations that may cause

Casing	porous material in the well bore.	borehole instability and provide protection from abnormally pressurized strata.
Production Casing	Coupling threads (connecting segments of casing) undergo rigorous testing.	Establish isolation between the producing zone and other subsurface formations.
Cement Selection	Cements and cement additives are carefully selected for every well in accordance with API Spec 10A and API RP 10B-2. Selected cements and additives are laboratory tested.	Confirms cement and additives meet the requirements of the well design.
Zonal isolation	Properly clean well bore with wiper trips.	Enables high integrity cement job.
Production Containment Barriers and Barrier Verification	Once the final casing string has been set, cemented, and the drilling rig released, the well construction as executed should be reviewed and a barrier analysis be performed prior to well completion, including hydraulic fracturing. A variety of short-term barriers may be employed during the completion phase, such as wellhead isolation tools and fracture strings.	The barriers used in well construction are designed to prevent unintended fluid flow, protects groundwater resources, and protect the well from corrosive environments.
Cementing	Prior to cementing investigate and review the history of nearby wells for cementing problems encountered, e.g. lost returns, irregular hole erosion, poor hole cleaning, poor cement displacement.	Informs treatment design to affect how cementing is conducted. Provides fluid control and protects groundwater resources.
	Use computer simulations to optimize cement placement procedures.	
	Use established drilling practices to achieve a uniform, stable wellbore with optimal hole geometry.	
	Ensure that the drilling fluid selection is appropriate for the designed well and the geologic conditions likely to be encountered.	
	Carefully select casing hardware (cement baskets, wiper plugs, etc.) to meet cement design objectives.	
	Besides regulations and industry standards on the top of cement location above hydrocarbon zones or groundwater, industry standards recommend top of cement locations for other reasons such as preventing annular pressure buildup and/or sustained casing pressure. See API 65-2, API 90-2, and API 96.	
Centralizers	Select casing centralizers to precisely center casing in well bore. Centralizers and their placement must also meet the standards set out in API RP 10D-2 and API TR 10TR4, which address calculations determining the number and placement of centralizers in vertical and deviated wellbores guidelines to determine which type of centralizer	Provides for effective mud removal and cement placement and provides that casing is entirely surrounded by cement, especially in critical areas, such as casing shoes, production zones, and groundwater aquifers.

	to use (the bow-spring design, the rigid blade design, and the solid design).	
	Thoroughly test cement slurry using representative samples of the cement mixtures and additives, using the water source that will be used to prepare the slurry. Test for • Slurry density; • thickening time; • fluid loss control; • free fluid; • compressive strength development; • fluid compatibility (cement, mix fluid, mud, spacer). • sedimentation control; • expansion or shrinkage of set cement; • static gel strength development; and • mechanical properties.	Confirms compatibility with site-specific geologic conditions. Address well-specific conditions.
	The density of the cement slurry must be based upon a laboratory free-fluid separation test demonstrating an average fluid loss of no more than 6 milliliters per 250 milliliters of cement tested.	Treatment design to account for variations in geology and allow proper bonding.
	Utilize cement systems that reduce cement slurry porosity and permeability, improve fluid loss control, and/or build gel strength rapidly in areas of known shallow gas that could cause poor cement bonding.	
	The cement should be mixed and pumped at a calculated rate/flow regime. This must be carefully monitored throughout the cementing process.	Provides consistent slurry density and inhibits channeling of the cement in the annulus.
	Well cementing must be monitored by a qualified professional.	Reduces operator-error.
	Cementing plan should include cement spacer design and volume. Specify low density "lead" cement and high density "tail" cement.	High density tail cement has high compressive strength and is used to isolate critical intervals.
	After cement is placed behind any casing installed below the conductor pipe, the operator must not disturb the casing until the cement achieves a minimum compressive strength of 3,500 kPa. The casing must not be disturbed for a minimum of 8 hours.	Provides casing and cement strength to withstand high pressures.
Cement integrity	Perform gamma ray, collar locator tests or a cement bond log in the	Determine the exact location of the casing, casing

logging	event a poor cement job is suspected.	collars, and quality of the cement job relative to each other and relative to the subsurface formations, and measure the quality of cement bond/seal between the casings and the formation. Used as baseline for subsequent well integrity monitoring.
	Conduct a formation leak-off or formation integrity test.	Verifies the cement integrity and determines formation integrity at the casing shoe is adequate to meet the maximum anticipated well bore pressure.
	In the event a poor cement job is suspected, perform thorough cement bond logging in casing strings (conductor, surface, intermediate, production). If the cement bond is not adequate to isolate these zones, remedial cementing will be required.	Evaluates cement-to-casing and cement-to-formation bonds.
	Prior to hydraulic fracturing, cemented casing strings, injection lines manifold, associated valves, fracture head or tree and any other wellhead components must be pressure tested to withstand pressures in excess of maximum expected pressures. Pressures may not drop more than 10% during pressure testing.	Confirms wellbore strength for hydraulic fracturing activity.
Fracture Treatment Monitoring	Continuously monitor the following during every phase of hydraulic fracturing a) surface injection pressure; b) slurry rate; c) proppant concentration; d) fluid rate; and e) all annuli pressures.	Monitoring to confirm no unexpected changes in pressure which may be indicative of leakage.
	Hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during hydraulic fracturing operations.	Design of treatment operation to protect wellbore components and environment.
	Differential pressures across the walls of any casing string must not exceed 80% of the casing's API-rated minimum internal yield pressure, throughout the hydraulic fracturing treatment.	
	Blow out prevention must include a remote blow-out prevention actuator that is: a) powered by a source other than rig hydraulics; and b) located at least 25 meters from the wellhead.	Provides an alternate source for blowout prevention to allow for independent operation.

Sources: API 2015a, New Brunswick 2013.

6.3.1.1 Fracture Monitoring

The use of visualization technology, also known as micro-seismic and micro-deformation mapping, is used by operators to monitor the hydraulic fracturing process and measure the size and placement of fractures. The results are then used to determine the extent of fractured rock resulting from the treatment by mapping the locations of induced micro-seismic events. This data is used to confirm that the fractures are separated from drinking water aquifers and any nearby water supply wells.

A significant amount of research and discussion has taken place about the vertical growth of hydraulic fractures and whether these fractures can create pathways for the fracturing fluids or hydrocarbons to migrate into groundwater resources. The vertical extent that hydraulic fractures can propagate is controlled by the upper confining zone or formation, and the volume, rate, and pressure of the fluid that is pumped. The confining zone will limit the vertical growth of a fracture because its physical properties are sufficiently different from the target formation, or an insufficient volume of fluid has been pumped. The greater the vertical distance between the fractured formation and the groundwater resources or water-bearing zones, the more likely the multiple overlying and underlying layers of rock formations will possess the qualities necessary to isolate the growth of hydraulic fractures.

Micro-seismic and micro-deformation mapping has been conducted on thousands of hydraulic fracturing jobs nationwide (Fisher and Warpinski 2011) and indicates that the growth of fractures vertically is relatively well-contained. Figure 6-1 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 study shows that no fracture jobs created fractures significantly outside the target formation, and greater than 4,000 feet separated the shallowest fracture from the deepest aquifer zone.

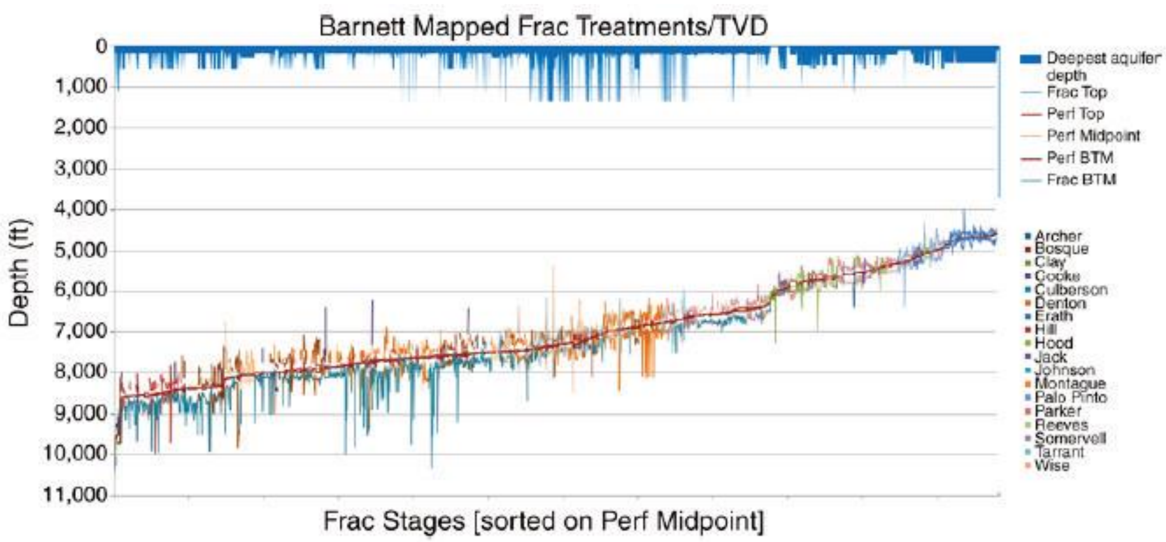


Figure 6-1. Fracture Growth Monitoring

6.3.1.2 Well Spacing

The robust industry standards and operational practices implemented regarding well integrity and the relatively short duration of elevated pressure during a hydraulic fracturing stage (approximately one hour) suggests that legacy and improperly abandoned wells located near hydraulically fractured wells are the more likely pathway for hydrocarbon or fracturing fluid migration into fresh water zones. Regulations for permitting oil and natural gas wells and industry practices include site characterization to identify nearby abandoned and operating wells, fractures and fault lines, and the location of the base of underground sources of drinking water. As such, operators evaluate proximity to existing wells to ensure that the hydraulic fracturing job is successful and stays within the target zone. During hydraulic fracturing operations, the injection pressures are monitored, and if pressures drop below designated thresholds, it will trigger immediate action (i.e., halting fracturing operations) and investigation. If fluid migration occurs through such a pathway, it would create a noticeable pressure drop in the well undergoing hydraulic fracturing treatment which would immediately be observed during pressure monitoring and would prompt appropriate inquiry (King 2012). There have been two examples of communication occurring between wells, and both times the hydraulic fracturing was terminated and the issue was inspected and addressed.

In addition, state regulations typically include requirements to evaluate well spacing when permitting new wells (e.g. Louisiana, Kansas, California, Pennsylvania, Texas) to prevent operations in one well from affecting nearby wells. These regulations apply to all new wells (i.e. both wells proposed for hydraulic fracturing and conventional production wells) and are addressed on a case-by-case basis when evaluating well permit applications.

6.3.1.3 Well Abandonment

API Guidance document 51R, *Environmental Protection for Onshore Oil and Gas Production, Operation, and Leases*, published July 2009, describes recommended practices for well abandonment. In addition, state regulations address well abandonment standards, including provisions for re-abandonment of closed wells under specified circumstances, such as to prevent effects from proposed activities (e.g., land redevelopment, hydraulic fracturing). Measures to avoid communication between hydraulically fractured wells, and nearby abandoned and operating wells are addressed through casing and cementing requirements of the well proposed for hydraulic fracturing (see Table 6-1 above) and considered when designing the hydraulic fracturing treatment.

6.3.1.4 Additional Considerations

In addition to these industry standards, it should be noted that there are also geological safeguards reducing the potential for impacting freshwater resources.

Figure 6-2 depicts the typical distance between the hydraulically fractured zone and the base of fresh water. As shown in the figure, the separation between these two areas ranges from approximately 1,500 feet in the New Albany and Antrim shale plays to well over 10,000 feet in the Haynesville-Bossier shale play. In the large plays with the greatest production, the separation is generally greater than 6,000 feet, providing over a mile barrier between the hydraulic fracturing operations and groundwater resources.

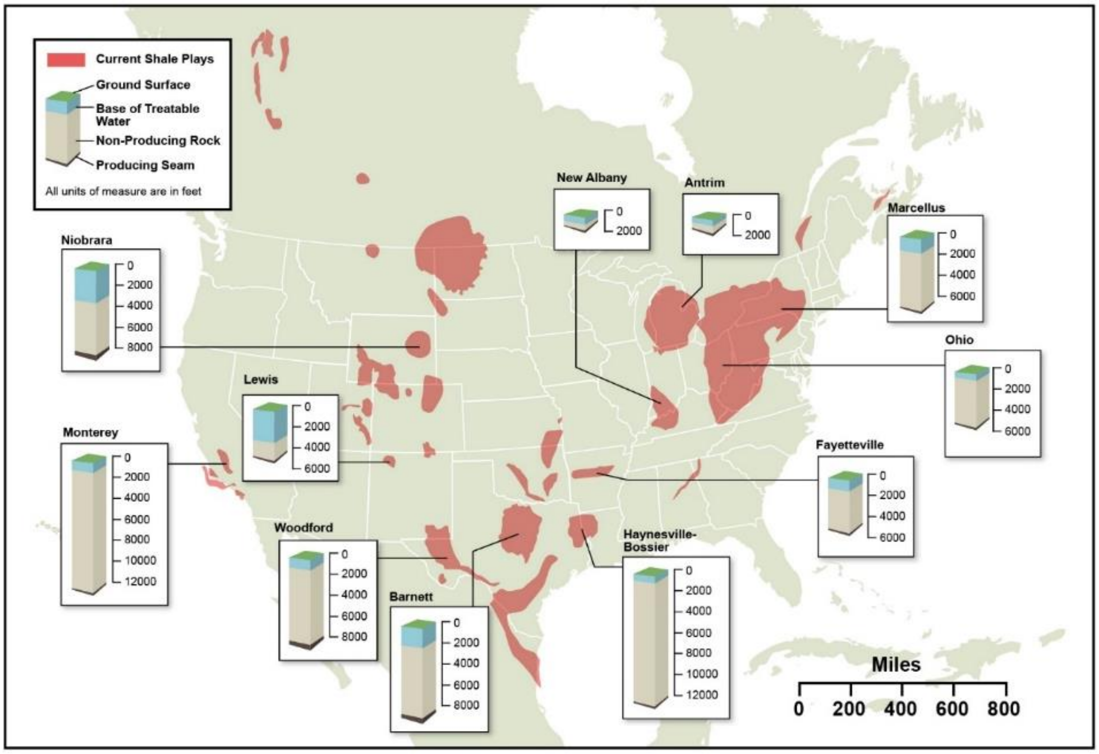


Figure 6-2. Vertical Separation between Hydraulic Fracturing Operations and Drinking Water Resources (prepared by Catalyst Environmental Solutions)

6.3.2 Industry Trends

6.3.2.1 Cement Technological Improvements

API has two guidance documents that provide the proven technologies for well cementing as well as practices for cement testing: 10A – Specification on Cements and Materials for Well Cementing (2011), and Recommended Practice for Testing Well Cements (2013). These cementing standards have been advancing and improving for the last several decades. In addition, well cement is an area of active research with several new cementing technologies available from service providers, including swellable elastomers, flexible cements, and low thermal gradient setting time cements. Hydraulic fracturing exerts high pressures on the well casing, which can induce cracking, and debonding between the casing and the cement, compromising zonal isolation. These emerging cement technologies can significantly reduce risks associated with compromised cementing integrity.

Downhole swellable elastomer technology is simple. A swellable compound is placed around the outside of the casing. When the compound comes into contact with the fluid it is designed to react with – oil or water – it swells to fill the annulus and creates a high pressure seal. Cement failure is most likely to occur between the cement and the casing, rather than between the cement and the formation, due to the temperature and pressure variation resulting in a cyclical expansion and contraction of the casing to which traditional cement cannot respond. The swellable elastomer is deployed like any other piece of casing pipe. If the cement fails at any time and fluid comes into contact with the elastomer, the elastomer is designed to swell sufficiently to bridge the gap between the casing and cement. The complicating factor comes when matching the swellable compound to the well fluid. No two wells have the same mix of fluids. The swellable elastomer must be developed based on site specific conditions to match the fluid conditions of the well, taking into account composition of the oil, salinity, and other chemicals present in the produced water. The technology is still relatively new, but swellable elastomers have already been successfully deployed in thousands of wells (Offshore 2008), and are a growing industry trend in cementing.

In addition, there are new flexible expanding cement systems that are applicable to high pressure stimulation that may cause traditional cements to crack or debond. In general, flexible expanding cements expand after setting, which improves the cement bonding and sealing and prevents unwanted stray gas migration. This cement system's mechanical properties are developed based on the site-specific downhole stress environment. The flexible cement is able to conform to the changes that occur during the drilling, production, and abandonment cycles of the well, minimizing risk of compromised well integrity.

6.3.2.2 Area of Review and Baseline Water Quality Monitoring

In addition to the API standard procedures associated with protecting underground sources of drinking water, recent state regulations specific to hydraulic fracturing are trending towards requiring operators to evaluate an "Area of Review," (AOR) specifically monitoring groundwater in areas around the subject well. The AOR has been standard practice related to permits issued under the Safe Drinking Water Act's Underground Injection Control (UIC) program. The UIC program is specifically intended to protect freshwater aquifers from injection wells, including produced water injection (Class 2 wells). Although the UIC program is not directly applicable to hydraulic fracturing, concepts such as the Area of Review are being adopted by some states for hydraulic fracturing projects.

In addition, some states are requiring baseline and ongoing groundwater quality monitoring, as described previously in Sections 3 and 4. As discussed in Section 3, states evaluate the specific geology and hydrogeology in the state, as well as with consideration of the volume of oil and natural gas activity and hydraulic fracturing that occurs in the state. Therefore, some states determine that additional water quality monitoring requirements specific to hydraulic fracturing are necessary (e.g., California), whereas others determine that the existing regulations for oil and natural gas development already provide the necessary water quality protections (e.g. Texas). For instance, in California, pursuant to Senate Bill 4, the State Water Resources Control Board has adopted groundwater monitoring criteria for hydraulic fracturing operations which includes monitoring wells upgradient and downgradient of the proposed operation within 0.5 miles of the surface projection of the zone proposed for stimulation (SWRCB 2015). In Colorado, new groundwater protection rules require that operators sample nearby water wells both before and after drilling activities. This will require sampling up to four water wells within one-half mile of a new oil and natural gas well prior to drilling, and two more samples of each well between six and 12 months and again between five and six years (COGCC 2015).

Baseline water quality evaluations are required in eight states with hydraulic fracturing. Even if not required by a state, operators frequently elect to proactively establish the baseline water quality to demonstrate that their operations are not impacting water quality. API recommends that upon initial development, planning, and resource extraction of a new basin, operators should review the available information describing water quality characteristics (surface and groundwater) in the area and, if necessary, proactively work with state and local regulators to assess the baseline characteristics of local groundwater and surface water bodies. On a site-specific basis, pre-drilling surface and groundwater sampling and analysis should be considered as a means to provide a better understanding of on-site water quality before drilling and hydraulic fracturing operations are initiated (API 2015b).

6.3.2.3 Tracers

The SAB recommends that the EPA should provide a discussion on the current use of tracers for injection fluids. Tracers are additive chemicals which allow the fluids used in drilling and/or hydraulic fracturing to be individually identifiable, thus making it possible to identify the source of fluids, if detected, migrating beyond the wellbore or the cemented well casings, respectively. Tracers can have unique signatures linked to individual hydraulic fracturing service companies to help identify whether, how, and who could be responsible for fluid releases beyond hydraulic fracture containment. The use of tracers is one tool to evaluate formation characteristics, well designs, and well performance. Since the 1950s, the use and number of tracers available has increased, although it is neither applied to all wells nor to all oil and natural gas fields.

The early tracers used in oil and natural gas development were radioactive tracers; these have evolved to those using water, oil or gas soluble chemical tracers. Use of tracers for shale oil and natural gas wells indicate the effectiveness of the hydraulic fracture stimulation and the connectivity of fractures created by well stimulation. The number of tracers is relatively small because they must be stable under the temperature, salinity, and pressure conditions found in the oil and natural gas reservoir. Aqueous non-charged radioactive tracers include tritiated water (HTO) and methanol (CH2TOH). Aqueous chemical tracers include thiocyanates (SCN-) and fluorobenzoic acids (Dugstad, 2007). Oil soluble tracers include alkyl esters, which partition in oil and water (Deans and Carlisle, 2007). However, Spencer et al. (2013) use hydrocarbon tracers that form unstable emulsions in the hydraulic fracturing fluids and dissolve in oil or natural gas upon contact with formation fluids. These tracers are used in evaluation of multi-stage fracturing operations. Natural gas tracers include sulfur hexafluoride (SF6). Solid tracers are mixed with polymers to form compounds that release tracer at a steady rate in the formation (Salman et al. 2014).

SECTION 7

Flowback and Produced Water

Large volumes of saline water, known as flowback and produced water, are produced during oil and natural gas development. Flowback water returns to the surface immediately after hydraulic fracturing and can contain up to 30% of the chemicals injected along with the water and sand. In contrast, produced water is extracted along with the oil and natural gas for the entire duration that a well is producing. The volumes of produced water and flowback vary significantly by region, and over time at a single well. Flow rates from shales are generally high initially and decrease over time throughout the production life cycle of the well.

During conventional oil and natural gas operations, produced water is frequently reinjected into the producing formation to enhance oil and natural gas recovery, counter subsidence, and minimize the need for surface discharge. However, reinjection back into the producing formation is typically infeasible and sometimes damaging to production during unconventional oil and natural gas development because the target formation has low permeability. Instead, produced water from unconventional operations is most often reinjected into other formations using purpose-built waste injection wells; a historic practice in Pennsylvania was to discharge to a public wastewater treatment facility, although this practice has ceased (Middaugh et al. 2014).

Flowback water can contain the chemicals that were injected into the well during hydraulic fracturing, and 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, including metals and naturally occurring radioactive materials.

7.1 SUMMARY OF EPA FINDINGS

The EPA Draft Assessment notes that the causes of produced water spills were reported to be (1) human error, (2) equipment failure, and (3) container integrity failure. More specifically, EPA identifies a variety of mechanisms by which produced water spills may occur, including:

- Faulty equipment;
- Spills during road transport of produced water (though data says this occurs at very low rates);
- Well blow outs;
- Leakage from storage impoundments;
- Unpermitted discharges; and
- Migration of constituents following land applications.

The EPA Draft Assessment notes that the causes of these spills were human error (38%), equipment failure (17%), failures of container integrity (13%), miscellaneous causes (e.g., well communication, well blowout), and unknown causes. Most of the volume spilled (74%), however, came from spills caused by a failure of container integrity.

7.2 SUMMARY OF SAB COMMENTS

The SAB has several comments on EPA's analysis of produced water and flowback water, starting with a clearer differentiation between the two. The primary concern is that EPA needs to provide a more robust analysis on the extent and duration of produced water leaks and spills, and the resulting impacts.

Primarily, the SAB comments that the EPA Draft Assessment should emphasize the advancements in produced water management and spill and release prevention over the last several years. Additionally, produced water treatment processes have improved dramatically over the last decade as the rise of hydraulic fracturing has challenged the status quo for produced water management.

7.3 INDUSTRY PRACTICES AND REGULATORY PROGRAMS

Oil and natural gas exploration and development generates large volumes of water daily. First, consider flowback water which is water that returns to the surface immediately after hydraulic fracturing and typically contains a high proportion of the fluids injected during hydraulic fracturing. Studies have found that the concentration of stimulation fluids returned in flow back water is highest immediately following hydraulic fracturing, and that these chemicals decrease in concentration over time. The period during which well stimulation fluids return to the surface following hydraulic fracturing varies by geography but has been found to range between a few hours to several weeks (CCST 2015).

Following this flowback period, produced water chemistry will generally be consistent with the chemical composition of the geology in which it resides. As such, 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 and is generally characterized as brackish water with elevated concentrations of TDS (including chloride and bromide) 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. Therefore, following the brief period immediately after hydraulic fracturing when the well stimulation chemicals are returned to the surface, the constituents of concern in produced water, which represents the majority of water produced from a well, are naturally occurring and not specific to hydraulic fracturing.

Produced water, which is extracted along with the oil and natural gas, as part of the production of any oil and natural gas well, occurs over the life of the well. Because large volumes of water are co-produced with oil and natural gas, it is possible that this water may spill or leak during transport and storage. However, industry has implemented a large number of operational practices and standards to reduce the frequency of releases and potential impacts associated with spills and leaks, including controls associated with tanks, lines, and well heads, where the majority of produced water leaks occur. As described below, there have been recent technological advancements to help reduce impacts from leaking impoundments. However, overall the existing protections have been largely effective, as evidenced by the fact that the majority of produced water spills result from human error and not by engineering or administrative controls. To reduce the incidence of human error, oil and natural gas companies are increasingly emphasizing the importance of training, plans, and procedures to reduce such incidences. Based on the EPA Draft Assessment's data analysis, only 8% of onshore produced water spills reached water resources. In addition, there has been in increase in produced water data tracking and accountability, and there have been research developments in using isotopic tracers to identify potential impacts associated with produced water.

An important industry trend associated with produced water is the increasing beneficial use/reuse of produced water, turning a historic waste that must be disposed of into a new source of water that displaces demand on potable water resources. These industry practices and trends are discussed in greater detail in the following sections.

7.3.1 Operational Practices

Section 7.3.2 describes standards and operational practices implemented by industry to reduce the incidence and potential impacts associated with chemical spills during hydraulic fracturing. These industry standards and operational practices are also largely applicable to reducing impacts associated with managing produced water and flowback water, from the time the waters discharge from the well head to the time the waters are used/recycled or disposed. Operational practices include site design, tank or impoundment design, including secondary containment, pipeline management, inspections and monitoring, and employee training. Produced water storage and disposal is discussed in additional detail in the following section.

7.3.2 Industry Trends

7.3.2.1 Produced Water Storage

Water associated with oil field operations may be stored in above-ground tanks or in lined, in-ground impoundments. The oil and natural gas industry's own management practices commonly advise against surface discharge of produced water into unlined impoundments, and regulations in many states are moving toward prohibiting use of unlined impoundments. The U.S. Department of Energy recommends that "all evaporation pits should be lined … to prevent downward migration of fluids" (U.S. DOE et al., 2009). Similarly, the Center for Sustainable Shale Development (CSSD), an independent organization with representation from oil and natural gas producers in the Appalachian Basin, adopted a zero surface discharge performance standard in 2013 (amended in April of 2016). CSSD's current standards require that any new impoundments be double-lined (CSSD 2013).

The use of unlined wastewater storage impoundments is being phased out in some states due to local factors. Kentucky, Texas, and Ohio have phased out the use of unlined impoundments for storage of well stimulation fluids (Kell 2011; 401 KAR 5:090 Section 9(5)(b)(1)). Pennsylvania requires, at a minimum, lining on all waste impoundments, whether for conventional or unconventional well fluids. If a liner is breached, all fluids must be prevented from leaking from the impoundment (PA Code of Regulations). Colorado, prohibits the use of unlined impoundments where communication with groundwater is likely, and prohibits the disposal of untreated produced water into unlined impoundments (COGC Rule). New Mexico also requires lining for all new impoundments (New Mexico Administrative Code).

Although evaporation-percolation in unlined surface impoundments (percolation pits) was a common disposition method for produced water from stimulated wells in California into the early 2000's, the SB 4 implementing regulations prohibit the storage of well stimulation fluids in unlined impoundments. In California, the Central Valley Regional Water Quality Control Board is in the process of developing General Orders to provide more comprehensive and uniform regulation of impoundments in Kern County where presently 685 active disposal ponds are located, in contrast to developing individual waste discharge requirements (WDRs) for each project (CVRWQCB 2016). Where impoundments are still used, fresh water is generally stored in impoundments with a single protective liner, while produced water is generally stored in impoundments with double liners, to reduce the possibility of leakage. In addition to double liners, impoundments used to store produced water are frequently constructed with leak detection and water-level monitoring devices (CH2M Hill2015). There is a trend towards the use of tanks and other storage vessels to reduce the need for impoundments in certain circumstances.

Larger centralized impoundments are designed and constructed to provide structural integrity for the life of their operation, taking into consideration their size and extended use. Proper design, installation and operation reduce the incidence of a failure or unintended discharge off the site; in some cases secondary containment or freeboard requirements are provided for additional capacity. Impoundments used for long-term storage of fluids are sited in accordance with state stream setback distances from surface water to prevent unauthorized discharge to surface waters. As noted in section 7.3.3, additional information may be required by regulatory authorities for centralized surface impoundments for fracture fluids. For such facilities, requirements may include an initial review of site topography, geology and hydrogeology, in addition to inspection and maintenance procedures—especially if such impoundments are within defined distances of a water reservoir, perennial or intermittent stream, wetland, storm drain, lake or pond, or a public or private water well or domestic supply spring. API RP 100-2 contains design criteria and considerations for design, construction, operation, and monitoring of impoundments, including secondary containment considerations. In addition, some states such as Colorado and California have developed or are developing additional regulations related to design and use of impoundments.

There have also been advances in the last several years in the design of large water storage systems, addressing variables such as soil composition and compaction, moisture control, and dual liner materials and thickness. An operator performed a study of various liner materials and determined that polypropylene liners prove a good combination of elasticity and strength, whereas high-density polyethylene and low-density polyethylene were not well suited to handle temperature fluctuations (CH2MHill2015). The grade or slope of each impoundment is carefully calculated based on on-site conditions to reduce potential for slope failure.

7.3.2.2 Data Management and Transparency

Many state agencies have begun developing publicly accessible and searchable databases that allow produced water spills and leaks data to be reported and stored. The driver for this information advancement is that more states are including “Produced Water” as a standardized selection on spill reporting forms. This input is then coded into the database and becomes searchable. This information allows for transparent disclosure of produced water spills and offers statistical data to monitor the frequency and intensity of these incidents.

7.3.3 Regulations

Regulations governing produced water management generally depend on the disposition of the water and how the produced water is ultimately disposed. As previously discussed, regulations exist that address impoundments used to temporarily store produced water on-site. Other relevant regulations are guided by produced water use/re-use and disposal options. For example, transport of produced water is regulated by the DOT, deep underground disposal wells are regulated under the UIC program, and discharges to surface waters that benefit agriculture or wildlife habitat are regulated by National

Pollutant Discharge Elimination System (NPDES) permits. Details on these regulatory programs are provided in Section 8.3.

SECTION 8

Wastewater Treatment and Waste Disposal

The EPA Draft Assessment refers to flowback water and produced water as "wastewater." In conventional oil and natural gas development, produced water may be injected back in to the producing formation to enhance oil recovery (EOR) and counteract the potential for subsidence. However, produced water from unconventional operations is most often disposed in other geologic formations using purpose-built waste injection wells. Formerly, primarily in Pennsylvania, produced water was sometimes discharged to a public wastewater treatment facility; this practice no longer occurs, and as of June 2016 it is prohibited by the US EPA effluent guidelines for onshore unconventional oil and natural gas extraction (40 CFR Part 435). The EPA Draft Assessment suggested that the most significant impacts to surface water resources associated with hydraulic fracturing result from management of wastewater (EPA 2015a).

Produced water is currently regulated as a waste in almost all jurisdictions. However, there is a current industry trend to beneficially reusing it under specific circumstances (Middaugh et al. 2014).

8.1 SUMMARY OF EPA FINDINGS

The EPA identifies several primary mechanisms by which wastewater could impact water resources including (1) inadequate water treatment prior to discharge, (2) accidental releases during transport or storage, (3) mismanagement of residuals following treatment, and (4) migration of chemicals following land applications. The EPA Draft Assessment addresses the findings that publicly owned treatment works (POTWs) may not be well suited to treat produced water because they are not designed to effectively reduce high TDS concentrations (EPA 2015a); and the June 2016 EPA effluent guidelines now prohibit this practice.

8.2 SUMMARY OF SAB COMMENTS

The SAB requests more information about wastewater treatment fundamentals, such as descriptions of different wastewater treatment technologies currently used to treat wastewater. The SAB also suggests including a discussion of trends in wastewater treatment systems, including scientific and economic drivers of change and potential future trends, focusing on the potential implications for impacts to water resources (SAB 2016).

8.3 INDUSTRY PRACTICES AND REGULATORY PROGRAMS

The water co-produced with oil and natural gas during exploration and development (both flowback water and produced water) has historically been regulated and managed as a waste. However, there is a trend among operators to treat and use produced water or treat and reuse produced water in their ongoing operations, rather than disposing of it. Operators are also investigating options to use/treat and reuse produced water for other purposes. A variety of treatment options are available and treatment technology continues to progress, as summarized in this section.

8.3.1 Underground Injection

Injection wells associated with oil and natural gas development are regulated by EPA's UIC program for Class I or Class II injection wells. The primary purpose of the UIC program is to protect underground sources of drinking water. The UIC program includes an analysis of other wells within the Area of Review (AOR) and zonal isolation of the injected fluids. Wastewater injection wells are typically Class II wells in the UIC program and require state and/or federal permits. Disposal of produced water and flowback fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound. This wastewater disposal method has been in practice for decades and is well-regulated and has proven to be effective.

8.3.2 Produced Water Treatment Technologies

A variety of well-understood treatment technologies exist, including physical separation, coagulation/oxidation, electrocoagulation, sedimentation, and disinfection. These technologies are effective at removing total suspended solids (TSS), oil and grease, scale-forming compounds, and metals, and they can reduce microbial activity. More advanced technologies targeting TDS and/or specific compounds are sometimes required for recycling for future hydraulic fracture jobs, or reuse for other beneficial purposes. Advanced technologies consist of membranes, thermal distillation technologies, crystallizers, ion exchange, and adsorption. Advanced treatment systems normally require pre-treating the water to optimize the more advanced treatment approach. Therefore, in most instances, a combination of basic and advanced treatment systems is needed to treat produced water for recycling or reuse. Some advanced treatment technologies can be made mobile for on-site treatment (EPA 2015a). The following sections describe the prevailing basic and advanced wastewater treatment processes.

8.3.2.1 Physical Separation

Physical separation is the most basic treatment need for oil and gas wastewaters, including produced water from hydraulic fracturing operations. Separation removes suspended solids, and oil and grease. Various down-hole blocking devices and basic separation devices have been used in the oil and natural gas industry for decades and are generally not specific to hydraulic fracturing operations. The specific method selected depends on the composition of the target produced fluids (EPA 2015a).

8.3.2.2 Solids Removal

Sedimentation is a basic treatment option, used either alone or as a pretreatment step for more advanced treatment technologies– to reduce the amount of solids going to subsequent processes. Many treatment systems include sedimentation tanks, or some form of settling basin to allow larger particles to settle out of the water. These particles are eventually collected, dewatered, and disposed of. Sediment removal can also be achieved with the use of sand filters, cartridge filters, or bag filters. All of these methods are sized and designed to remove sediment down to a specified size fraction, depending on the specific need. Sedimentation is a longstanding treatment method utilized by the oil and gas industry (EPA 2015a).

8.3.2.3 Coagulation/Oxidation

Coagulation, another basic treatment method, is the process of applying coagulant chemicals to cause agglomeration of small particles into larger particles. In combination with oxidation, coagulation and sediment removal pretreats the water stream so that the subsequent oxidation step is more effective. Chemical coagulants are used to precipitate suspended solids, some dissolved solids, and metals from hydraulic fracturing wastewater. Adjusting the pH increases the ability for some constituents to precipitate out of the solution. Chemical precipitation is often used in industrial wastewater treatment as a pretreatment prior to oxidation treatment. Oxidation breaks down hydrocarbons ultimately to carbon dioxide and water through the use of ozonation, or by the addition of oxidizers such as peroxide. The resulting water stream is relatively free of suspended solids and hydrocarbons. This technique has been applied to hydraulic fracturing wastewaters using on-site and mobile systems. The produced solid residuals from coagulation/oxidation processes typically require further treatment, such as de-watering (EPA 2015a).

8.3.2.4 Reverse Osmosis

The reverse osmosis (RO) treatment process is sometimes used in treating produced water because it effectively reduces total dissolved solids (TDS). Other membrane technologies include microfiltration, ultrafiltration and nanofiltration. While these membranes all effectively reduce total suspended solids (TSS), only nanofiltration and RO effectively reduce TDS.

The RO process separates dissolved solids or other constituents from water by passing the water solution through a semi-permeable membrane. The water is able to pass through the membrane, while the constituents are too large to pass through the pores. In general, the RO process is capable of filtering or treating bacteria, salts, dissolved solids, proteins, and other constituents. The membrane may be a polymeric membrane, or a ceramic membrane. The ceramic membrane is more robust and is more common in produced water applications.

The RO process requires energy, normally pressure supplied by a pump, to force the solution through the membrane. As the pressure increases the concentration of solution passing through the membrane also increases. Subsequently, the build-up of dissolved solids along the membrane requires continually increasing energy to pass the pure water through the membrane. Most RO technologies utilize a cross flow process so that the membrane continually cleans itself. As a portion of the solution passes through the membrane, the remaining fluid is flushed downwards across the membrane to move constituents away from the membrane.

Membranes are sensitive to iron, manganese, hardness, polymers, and other compounds that can lead to fouling. As such, a pretreatment train is typically provided to extend the life of the membrane. The efficiency of the membrane to collect particles depends on the concentration and chemical properties of constituents, membrane type, temperature, and general operations. For RO to be feasible there must be a relatively large volume of produced water; at low flow rates, the brine concentration and pressure is difficult to maintain across the membrane, and removal efficiencies are low. In addition, RO may be limited to treating TDS levels of approximately 40,000 mg/L TDS. RO treatment produces a highly concentrated brine that must be properly disposed of (Veil et al. 2004).

8.3.2.5 Mechanical Vapor Recompression

There are several types of evaporators available. Although not in common use, a mechanical vapor recompression evaporator can be used for some produced water treatment applications. Vapor recompression evaporation uses a compressor to increase the pressure of the vapor and an increase in the condensation temperature. The efficiency and feasibility of this process depends on the efficiency of the compressing device, and the efficiency of the heat exchanger. This process is energy intensive and is used when the objective is clean effluent for direct/indirect discharge or if clean water is needed for reuse. A vapor-compression evaporator can produce treated water down to approximately 500 mg/L TDS, and typically has very small volumes of residual waste (i.e., brine). Evaporators can be subject to plugging, as such, pretreatment is required to remove fines (EPA 2015a).

8.3.2.6 Ion Exchange

Ion exchange is appropriate for selective removal of components of produced water. The ion exchange process works by charging resins (synthetic, bead-like spheres) so that ions in the water are attracted to the resin and attach themselves to the resin, replacing the ions that are already attached. The ion exchange process can effectively remove salts, heavy metals, radium, nitrates, arsenic, uranium, etc., from raw water, but not organics. Softening and deionization are the two most common ion-exchange methods. Softening is used primarily as a pre-treatment method to reduce water hardness before reverse osmosis (Veil et al. 2004; ALL Consulting 2013). The equipment required is typically a container with ion exchange resins or other materials that selectively remove larger ions.

8.3.2.7 Freeze-Thaw/Evaporation

The Freeze-Thaw/Evaporation (FTE) process involves lowering the freezing point of water containing salts or other constituents below the freezing point of pure water (32°F). Partial freezing of the solution results in the formation of higher quality ice crystals than the water from which it was derived, and the concentration of the higher density dissolved solids and other constituents in the unfrozen liquid. The ice crystals can then be collected and thawed, providing a source of high quality water with more management options, or in appropriate regions, the crystals can be allowed to evaporate. This process can be repeated until the more concentrated effluent is of a manageable volume. The smaller volume of effluent, though more concentrated, can be more easily disposed of and/or discharged with an appropriate NPDES permit, if necessary (ALL Consulting 2003).

8.3.2.8 Ultraviolet Light Disinfection

Ultraviolet (UV) sterilization is a proven technology for the treatment of water and the removal of unwanted free-floating constituents. UV treatment is effective at killing bacteria, viruses, fungi, algae, and protozoa disrupting the cells ability to multiply. UV light does not effectively remove dissolved constituents from water. Shadows created by the suspended solids also disrupt the performance of UV light to kill microbes and thus, as with other water constituent types, raw water containing large concentrations of suspended solids would need to be pre-filtered.

Some hydraulic fracturing applications may require disinfection to kill bacteria after treatment and prior to reuse. Chlorine is a common disinfectant. Chlorine dioxide, ozone, or ultraviolet light can also be used. This is an important step for reused water because bacteria can cause problems for further hydraulic fracturing operations by multiplying rapidly and causing build-up in the well bore, which decreases gas extraction efficiency (ALL Consulting 2003).

8.3.2.9 Summary

Table 8-1 shows the efficacy of various basic and advanced treatment options. A + symbol indicated a removal efficiency of 1 to 33%, a ++ symbol indicated removal efficacy of 34% to 66%, and +++ indicates removal efficacy of and greater than 66%. Cells marked with a dash indicate that the treatment technology is not suitable for removal of that constituent or group of constituents. Note that the majority of the basic treatment technologies primarily reduce TSS and organics, which the advanced technologies treat a wider range of constituents (EPA 2015a).

Table 8-1. Removal efficiency of wastewater treatment technologies.

Treatment Technology	Hydraulic Fracturing Wastewater Constituents					
	TSS	TDS	Anions	Metals	Radio-nuclides	Organics
Basic Treatment Technologies						
Physical Separation - Hydrocyclones	+++	--	--	--	--	++
Physical Separation - Dissolved air flotation	+++	--	--	--	--	++/+++
Chemical precipitation	+++	--	--	+++	+++	+++
Sedimentation	++	--	--	--	--	--
Advanced Treatment Technologies						
Freeze-thaw evaporation	+++	+++	Assumed	+++	--	+++
Reverse osmosis	--	++/+++	+++	++/+++	+++	+/++/+++
Advanced oxidation and precipitation	--	+	--	+/+++	--	+++
Membrane filtration (other)	+++	--	--	+++	--	++/+++
Forward osmosis	--	+++	Assumed	Assumed	--	--
mechanical vapor recompression		+++	+++	+++	+++	+/++/+++
Ion exchange	--	--	+++	+++	+++	+/++/+++
Crystallization	--	+++	Assumed	Assumed	--	--

Source: EPA 2015a

Note: A + symbol indicated a removal efficiency of 1 to 33%, a ++ symbol indicated removal efficacy of 34% to 66%, and +++ indicates removal efficacy of and greater than 66%.

Cells marked with a dash indicate that the treatment technology is not suitable for removal of that constituent or group of constituents.

8.3.3 Operational Practices and Industry Trends

8.3.3.1 Technological Innovation in Treatment Technologies

Demand for using/reusing produced water or using brackish/saline water is driving technological innovation. Technological advancements from other water treating industries are being adapted to work with the high salinity water that results from hydraulic fracturing. There has recently been accelerated research into desalination technologies, including reverse osmosis and other membrane innovations, as well as mechanical vapor recompression, and carrier gas extraction, to name a few. The demand of innovation will result in these technologies become more widely available much sooner for the broad potable water market at large, and at lower costs. New alternatives are continuously being considered and evaluated, and operators keep abreast of new developments in this field (API 2015b).

Emerging Treatment Technology

Forward osmosis (FO) is a new treatment technology that is currently being tested by the US Bureau of Reclamation. FO can desalinate brackish water and seawater using less energy and at potentially lower costs than reverse osmosis (RO). In addition, pressurized FO converts osmotic pressure to hydroelectricity for production of electric power. The success of FO applications relies on the development of new ultra-thin membranes, which the USBR is currently studying and piloting (Moody et al. ND).

Wastewater Treatment Case Study

One operator partnered with a startup company that utilizes a new technology to desalinate produced water. The technology uses a carrier gas extraction (CGE) process that desalinates water with less energy and lower operating costs than comparable commercial technology. A treatment plant pretreats the water, and the CGE process reduces TDS from about 120,000 parts per million (ppm) to about 500 ppm. In a pilot project the first-of-a-kind treatment plant was successfully installed and operated (CH2M Hill 2015).

Treating produced water to freshwater standards can be complex, but it can provide operators with greater flexibility for storage, transport and especially reuse. In contrast, treating water to clean-brine standards is easier but may result in use/reuse incompatibilities and higher expenses than comparable brackish fracturing fluids. Due to the complexity of hydraulic fracturing flowback fluids and produced water, it is likely that multiple processes will be required in many, if not most unconventional plays. Key considerations are the performance and cost-effectiveness of the water treatment process. For example, distillation is an energy intensive process. It may only become an option for most operations with technological improvements to increase the treatment effectiveness and the overall efficiency of the process (API 2015b). The volume of water produced is also an important consideration. In some cases, the scale of treatment operations may limit the feasibility of certain treatment technologies. Final considerations for selection of treatment options include the resulting waste stream, which is often a highly concentrated brine, and its appropriate disposal and the use/reuse options for the treated water.

8.3.3.1.1 Treatment Costs

Produced water management can be one of the most expensive aspects of the oil and natural gas production process. Treatment costs depend on a variety of factors, including the cost of the treatment infrastructure and technology, water quality and volume, end use, and transportation costs. According to the USBR Study, operational cost estimates for produced water treatment range from $0.20 to $8.50 per barrel (bbl)[42 gallons]. The study does not provide a basis to compare capital costs. Reverse osmosis tends to be less energy intensive than other thermal treatment processes and membrane technologies and therefore become more cost effective, especially when TDS concentrations are less than approximately 40,000 mg/L. The operational cost of the water treatment, excluding infrastructure costs, has been reported to be approximately $0.10 per barrel. In contrast, electrodialysis is more expensive than RO but does not require as much membrane maintenance, which can reduce costs.

Electrodialysis treatment costs have been estimated to be under $0.15 per bbl for an 8,000 bbl/day treatment process, not including capital costs. The cost for a typical ion exchange system ranges from $0.05 to $0.20 per barrel of treated water, depending on the influent composition. With regard to UV treatment, cost estimates from one water treatment provider indicated a range of $0.60 to $0.75 per barrel. Typical waste disposal into an injection well in the Barnett play costs about $2-2.5 per barrel. In comparison, the evaporation method costs approximately $3.0 dollars per barrel to only process the water. This cost increases to $3.0 to $5.0 when transportation, energy and other associated costs are taken into consideration. All price ranges provided below are subject to a variety of factors and may vary significantly in different states and shale plays. These costs are summarized in Table 8-2 below. As with most technologies, as water treatment technologies become more widespread they become more efficient and economies of scale help bring down the per unit cost.

Table 8-2. Estimated Costs for Produced Water Treatment

Treatment Method	Cost (per barrel)
Reverse Osmosis	$0.10
Electrodialysis	$0.15
Ion Exchange	$0.05 to $0.20
UV treatment	$0.60 to $0.75
Injection	$2-2.5
Evaporation	$3.0
Treat/discharge	$1-$2.10

Source: ALL Consulting ND. Treatment costs current within approximately five years. All costs are based on vendor specifications and may have changed.

Location is an important factor when considering treatment costs. Many developed on-shore oil and natural gas fields have existing injection wells or treatment facilities available, which can significantly reduce both capital and operating cost. Where new facilities must be constructed, the cost of treatment increases significantly to account for the capital costs (NPC 2011). In addition, transportation costs associated with moving produced water offsite for treatment and/or disposal can significantly increase costs. Trucking costs may range from $0.50 to $8.00 per barrel depending on the state and transportation distance (USBR 2014). Table 8-3 illustrates that costs for wastewater treatment and disposal can vary significantly across geographies, with injection costing as little as a penny per barrel in California to as much at $4.50 in Louisiana and Texas.

Table 8-3. Disposal Costs for Produced Water at Offsite Commercial Facilities

State	Type of Disposal Process	Costs per bbl.
CA	Evaporation/injection	$0.01-$0.09
KY	Injection	$1
LA	Injection	$0.20-$4.50
NM	Evaporation	$0.25-$0.81
NM	Evaporation/injection	$0.69
NM	Injection	$0.69
OK	Injection	$0.30
PA	Treat/discharge	$1-$2.10
PA	Treat/POTW	$1.25-$1.80
PA	POTW/road spread	$1.30-$4.20

PA	POTW	\$0.65-\$1.50
TX	Injection	\$0.23-\$4.50
UT	Evaporation	\$0.50-\$0.75
WY	Evaporation	\$0.50- \$2.50
WY	Treat/injection or discharge	\$0.96
WY	Injection	\$0.60-\$8.00

Source: Veil et al 2004 (http://www.ipd.anl.gov/anlpubs/2004/02/49109.pdf)

8.3.3.2 Trends in POTWs and CWTs

There is an industry trend away from reliance on publicly-owned treatment works (POTWs) and central waste treatment facilities (CWTs), as noted by the EPA Draft Assessment. These treatment facilities are not specifically designed to manage high TDS concentrations, and unless the plant utilizes specialized processes to remove bromide and chloride, it is possible that downstream drinking water intakes may have high concentration of these constituents. For lower TDS concentration produced waters, however, POTW and CWT discharge is still viable.

Discharge of produced water to POTWs primarily occurred in Pennsylvania, and operators there had been phasing out the practice of sending wastewater from hydraulic fracturing to POTWs entirely. As of June 2016, the US EPA effluent guidelines prohibit this practice in the U.S.

For CWTs, there are a variety of trends and best management practices in use to help minimize potential impacts to water quality resulting from discharging treated produced water. When water is sent to, treated, and discharged from CWTs, there are strict discharge requirements for TDS. In many instances, CWTs have shifted towards treating water for beneficial reuse rather than surface discharge. (See section 8.3.4).

In some oil and natural gas producing regions, the evolving practice is to set up temporary treatment facilities located in active drilling development areas or to treat the waste stream onsite with mobile facilities. The temporary facilities can alleviate/reduce the trucking of waste streams by the use of transitory pipeline systems that serve local wells. Permits for a dedicated treatment facility include specific discharge limitations and monitoring requirements (API 2015b).

For example, one operator frequently constructs and operates on-site CWTs. They recycle their produced water and in some instances that of third parties as well. As a result, this operator has nearly achieved zero-disposal of their produced water. During active times when drilling rigs are in use and hydraulic fracturing operations are underway, no produced water is discharged. However, when demand for treated water drops below the supply then water is treated at the on-site CWT and either beneficially reused or discharged (CH2M Hill 2015).

Similarly, an operator that works in two different fields in the Green River Play in Utah has built dedicated treatment facilities in both locations. The operator treats and reuses 98% of their produced water, which was able to fill approximately a third of their water demand for hydraulic fracturing in 2014 (CH2M Hill 2015).

8.3.3.3 Reducing Waste

There is an industry trend towards reducing the volume of waste that is generated and requires disposal. Operators follow a waste management hierarchy as follows: (1) source reduction, (2) reuse, and (3) disposal. Alternative base fluids are increasingly being used for hydraulic fracturing operations which potentially reduce the volumes of wastewater produced, as described in Section 2. Operators also regularly review the effectiveness of each additive so as to ensure the minimum amount of chemicals is used to meet the operational performance objectives. Operators reuse solid and liquid wastes to the extent possible. This is an area of continually improving technology. When waste disposal is determined to be the best waste management alternative, operators dispose of wastes in accordance with relevant state and federal regulations. Note that while certain waste materials generated during exploration and production are exempt from federal regulation as hazardous waste under the Resource Conservation and Recovery Act (RCRA), those waste materials are subject to state regulations (API 2015b).

8.3.3.4 Use/Reuse of Produced Water

There is a current regulatory and industry trend towards recognizing that produced water is a potential source of new water. The U.S. Bureau of Reclamation, the federal agency responsible for managing our nation's water resources, supports the beneficial reuse of produced water and has released several guidance reports pertaining to produced water beneficial reuse (Dahm and Chapman 2014; Guerra et al. 2011) and has funded innovative technological research for produced water treatment and reuse technologies (USBR 2012).

Examples of produced water use/reuse options span from treating for field use, to crop irrigation, industrial wash water, golf course irrigation, wildlife habitat support, livestock watering, or treatment and use/re-use for future hydraulic fracturing operations. A variety of case studies in which oil and natural gas operators are treating and using/re-using their produced water for future hydraulic fracturing operations are described in the Section 4.3.3.1 (Water Acquisition). In order to effectively reuse their produced water, the operator must fully understand and consider (1) the water quality of their produced water, (2) the local water needs, (3) the compatibility between water quality of the produced water and water quality needs for the target end use, and (4) the appropriate treatment method, if necessary. Figure 8-1 is a water quality compatibility chart that shows the salinity requirements of different possible target end uses. If the water quality of the subject produced water does not meet the quality requirements of the target end use, then treatment would be required. Note that this chart only addresses salinity (Middaugh et al. 2014).

Produced water has been increasingly used/reused across the country as well as internationally, demonstrating that use/reuse of produced water can gain regulatory approval and local acceptance. As regulatory hurdles ease, not only can the impacts associated with produced water disposal be reduced, but produced water can provide an important new source of water.

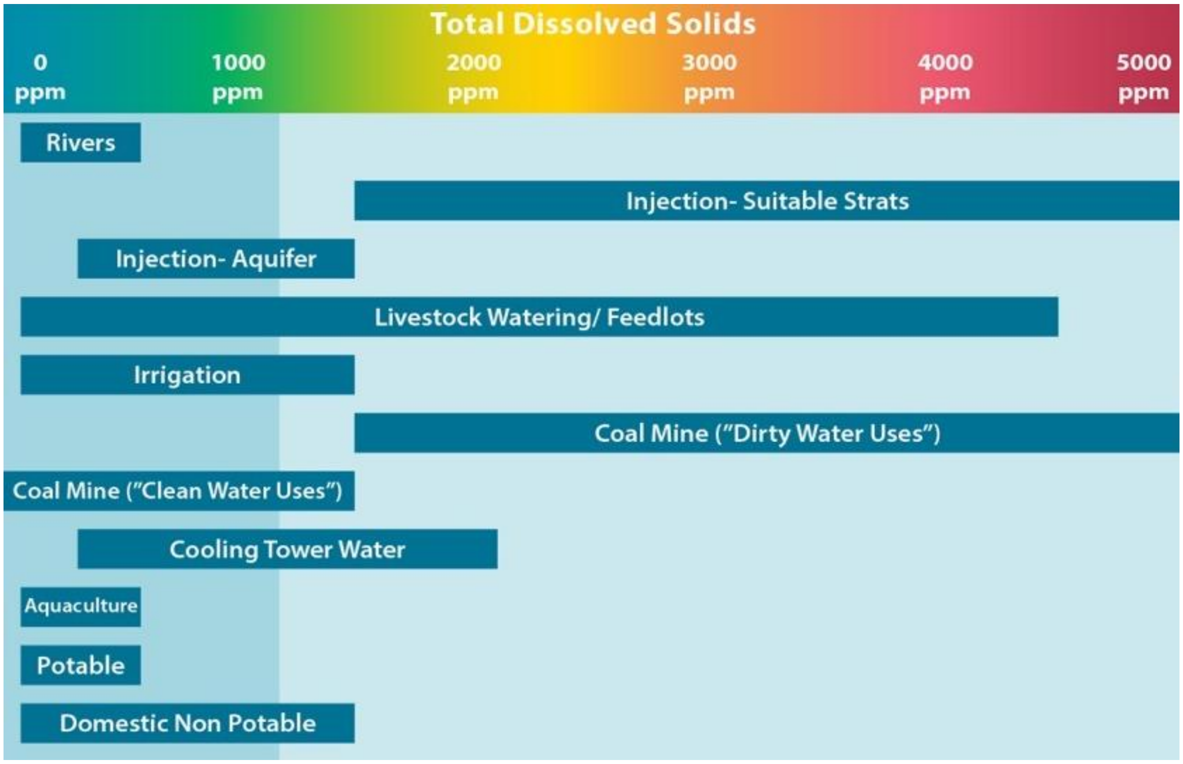


Figure 8-1. Site-Specific Produced Water Beneficial Reuse Compatibility Chart

8.3.4 Regulations

Direct discharges of oil and natural gas extraction wastewater pollutants from onshore oil and gas facilities to waters of the U.S. have been regulated since 1979 under EPAs Oil and Gas Effluent Limitations Guidelines and Standards (40 CFR part 435), the majority of which fall under subpart C, the Onshore Subcategory. The limitations for direct dischargers in the Onshore Subcategory represent Best Practicable Control Technology Currently Available (BPT). The BPT-based limitations for direct dischargers require zero discharge of pollutants to waters of the U.S. In June 2016 the EPA expanded the effluent guidelines to prohibit discharge of produced water from unconventional oil and gas extraction to POTWs. EPA's General Pretreatment regulations prohibit the introduction of hydraulic fracturing wastewater into a POTW if the produced water would introduce any pollutants that "pass through" or cause "interference" with POTW operations.

In the case of direct discharges from CWTs, discharges are regulated by a NPDES permit. Additional techohnology-based limits may be required if the wastewater contains pollutants from hydraulic fracturing-related wastewaters that were not originally considered in developing the effluent guidelines for the CWT, such as TDS, specific ions, such as chlorides and sulfate, specific radionuclides, and metals. In such instances, NPDES regulations require that technology-based limits are developed on a case-by-case and best professional judgement basis to ensure that wastewaters with residual contaminants are not discharged. NPDES permits often restrict high TDS discharges and in turn restrict metal effluent concentrations due to the additional treatment required to treat TDS (Weatherford 2015).

As discussed in Section 8.3.1, produced water disposed via deep underground injection is regulated under the UIC program of the Safe Drinking Water Act.

SECTION 9

Conclusion

An extensive array of industry practices and standards, trends, and regulatory programs exist which protect water resources from potential impacts of hydraulic fracturing at every step of the hydraulic fracturing water cycle, from initial water acquisition, through well injection to wastewater disposal. In addition, water management is taking an increasingly prominent place in corporate governance of oil and natural gas companies to reduce risks and improve sustainability. This report has attempted to summarize the most relevant of these industry practices, standards, and trends to the EPA Draft Assessment and in response to SAB comments on the EPA Draft Assessment.

Another important advancement in the industry has been increased collaboration among companies to share lessons learned and best practices, as well as improved public outreach to inform the public about advances in science and technology and address community concerns. While some areas with hydraulic fracturing have had an active oil and natural gas industry for many years (for example, Texas and California), other areas are experiencing oil and natural gas development for the first time, or at a greatly increased level that the past, as a result of the ability to extract oil and gas from shale deposits using hydraulic fracturing. Especially in areas in which the oil and natural gas industry is relatively new, proactive engagement between operators, regulators and the public can help assuage concerns related to hydraulic fracturing and has resulted in positive solutions for the environment. Table 9-1 describes a number of these groups and their primary goals. These efforts demonstrate the importance industry places on water resources, and the systematic programs in place and expanding which ensure an environment seeking continuous improvement. API has an entire guidance document dedicated to this topic - in API 51R [3], Annex A—Good Neighbor Guidelines. In this guidance, API recommends proactive consultation with the appropriate governing bodies to help ensure the local considerations are addressed.

Table 9-1. Industry Collaboration and Outreach to Promote Continual Environmental Improvement

Barnett Shale Energy Education Council (BSEEC)	Provides information to the public about production in the Barnett Shale Region, especially with regard to urban oil drilling. Promotes best practices and community relations.
Barnett Shale Water Conservation and Management Committee	This consortium of energy companies studies the industry's water use in the Barnett shale and discusses conservation and water management techniques to help conserve freshwater resources.
Environmentally Friendly Drilling	Undertakes field testing and research projects to evaluate technologies and best management practices developed in order to minimize the impacts of natural gas exploration and production with a focus on issues related to land, air, surface and ground water, emissions and societal impacts.
FRACFOCUS	A national hydraulic fracturing chemical registry created to provide the public access to reported chemicals used for hydraulic fracturing. To help users put this information into perspective, the site also provides objective information on hydraulic fracturing, the chemicals used, and the purposes they serve and the means by which groundwater is protected.
State Review of Oil and Natural Gas Environmental Regulations (STRONGER)	STRONGER shares innovative techniques and environmental protection strategies. It also reviews state regulatory programs and identifies opportunities for program improvement.

Source: API 2011

Catalyst ENVIRONMENTAL SOLUTIONS

SECTION 10

Preparers

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Disciplines

- Geology
- Geochemistry
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Dr. Tormey is a geologist, geochemist, and engineer with well-developed skills in framing and analyzing environmental issues, and in communicating complex ideas to a wide range of audiences. Noted for the creativity of his approaches, he has served as either a project manager or task manager for many controversial CEQA and NEPA projects. His work is primarily related to projects in Energy, Water, and Climate Change. He has managed projects under 3rd party contracts for regulatory agencies (US Bureau of Land Management, US Bureau of Reclamation, US Forest Service, Federal Energy Regulatory Commission, US Army Corps of Engineers, California Public Utilities Commission, California State Lands Commission, and San Diego Regional Water Quality Control Board, and others) and for Project applicants (oil and gas companies, electric utilities, property developers, and water districts).

He has served as project manager/task manager for important assignments in the energy industry. Dr. Tormey was the principal investigator for the peer-reviewed, publicly-available, Hydraulic Fracturing Study at the Baldwin Hills of southern California, on behalf of the County of Los Angeles and the field operator, PXP. He is on the Steering Committee of the study of the effects of Hydraulic Fracturing in California, completed in July 2015 by the California Council on Science and Technology (CCST). He was named by the National Academy of Sciences to the Science Advisory Board for Giant Sequoia National Monument; is a Distinguished Lecturer for the Society of Petroleum Engineers; is on the review committee on behalf of IUCN for the UNESCO World Heritage Site List; and was an Executive in Residence at California Polytechnic University San Luis Obispo Dr. Tormey was selected to manage the first and only EIS for FERCs backstop authority under the 2005 Energy Policy Act, and was environmental lead for major electrical utilities through the introduction of market competition in California. He was technical lead on the first EIS for a liquefied natural gas (LNG) terminal under the USCG (Pelican Port in the Gulf of Mexico), and project manager for the first LNG terminal offshore of California (Cabrillo Port). Dr. Tormey has been at the forefront of evaluating the impacts of development projects on global climate, including the first ever NEPA analysis that included quantification of the Social Cost of Carbon (for Navajo Mine/Four Corners Power Plant in New Mexico). He has also evaluated climate mitigation strategies, including technology replacement, carbon capture and storage, and carbon sequestration. Dr. Tormey is also actively working in the field of adaptation to climate change, including consulting with water and energy companies regarding the likelihood of changes to water-dependent operations, and the effects on endangered species.

Catalyst ENVIRONMENTAL SOLUTIONS

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Disciplines

- Environmental Management, Permitting, & Compliance
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Ms. Middaugh has six years of experience as an environmental scientist and planner. She has worked in the public, private, and NGO sectors. Ms. Middaugh has a strong understanding of state and federal regulations and environmental policy. She serves as both manager and technical expert for the preparation of complex and controversial environmental analyses. She also prepares California and federal permits. Ms. Middaugh is an expert on oil and gas operations, including hydraulic fracturing. She has also helped clients optimize risk reduction by developing an innovative method to analyze and prioritize risks.

Ms. Middaugh co-authored a peer-reviewed, comprehensive study of the physical and environmental effects of two specific hydraulic fracturing jobs at an existing oil and gas field in the center of Los Angeles. The objective of the study was to provide factual information supported by a high quality dataset.

Ms. Middaugh has co-authored two white papers commissioned by the American Petroleum Institute. One paper summarizes all of the literature published to date relating hydraulic fracturing and potential impacts to water resources and provides an analysis of key issues areas, including contamination pathways, hydraulic fracturing additives, methane in groundwater, and water supply. Ms. Middaugh performed a literature review, analyzed geologic information, and prepared a graphical report comparing different physical aspects of ten shale basins in the USA. The graphics included elements essential in understanding the petroleum geology of the basins; petroleum development history; paleogeography during organic sediment accumulation and geologic structure and cross sections of each basin. Ms. Middaugh also transformed the graphic report into an interactive video presentation hosted online for public education.

Ms. Middaugh has also co-authored three papers for the Society of Petroleum Engineers related to hydraulic fracturing. The first provides an analysis of the first ever comprehensive environmental monitoring of two high-volume hydraulic fracturing jobs, the second provides a framework to beneficially reuse produced water, and the third analyses how the medial shows public perception of hydraulic fracturing as well as the regulatory process.

Ms. Middaugh founded and leads Catalyst's environmental communications business unit, which is dedicated to clearly explaining environmental science to the public. She designed and executed communications strategies for clients with high-profile energy and land development projects in populous areas to help improve community relations and gain a "Social License to Operate."

Megan Schwartz

Director of Regulatory Compliance and Permitting

Ms. Schwartz has eleven years of experience as an environmental planner and project manager. She has addressed many controversial issues related to energy development in the southwestern US and globally. She works with electrical utilities, the oil and gas industry, and regulatory agencies with jurisdiction over energy production. She has worked on a variety of energy issues, including relicensing and decommissioning of hydroelectric power projects, oil and gas development, hydraulic fracturing, and retiring or repowering coal generation facilities, with a primary focus on water quality and community compatibility. She has also evaluated environmental effects of submarine cable installation, natural gas storage, and installation of new transmission lines connecting to wind energy sources.

Ms. Schwartz has extensive current experience addressing issues related to the oil and gas industry. Ms. Schwartz works with the California Independent Petroleum Association to coordinate and communicate with operators in California on issues related to underground injection control and aquifer exemptions. Ms. Schwartz was a co-author of the Inglewood Oil Field Hydraulic Fracturing Study, as well as a comprehensive review of the potential impacts of hydraulic fracturing on water resources for the American Petroleum Institute. She has also evaluated regulatory and environmental risks associated with oil field service companies providing hydraulic fracturing services for a large energy corporation, and prepared an Environmental and Social Impact Assessment for a potential oil field development project in Mississippi. Ms. Schwartz has prepared numerous CEQA documents for oil field projects in the Los Angeles Basin, addressing produced water treatment, catch basin construction and maintenance, and well pad development. She also works with operators to evaluate environmental constraints of proposed projects and refine project design to minimize environmental impacts prior to the development of any permit applications.

Ben Pogue

Director of Environmental Policy & Natural Resource Management

Mr. Pogue has over 10 years of professional experience performing natural resource analysis and environmental compliance for a wide range of public, private, and tribal clients. His primary area of practice is managing complex commercial energy projects through the federal compliance processes, including the National Environmental Policy Act (NEPA), Endangered Species Act, Federal Land Policy & Management Act, and National Historic Preservation Act. Throughout his career, Mr. Pogue has developed rapport with the Bureau of Land Management (BLM), U.S. Forest Service (USFS), Department of Energy (DOE), and Bureau of Indian Affairs (BIA) district offices across the western U.S. Mr. Pogue is experienced in the technical areas of socioeconomics, environmental justice, facility siting of energy facilities, recreation, visual resources, federal Indian trust policy, land use planning, and natural resource management.

Mr. Pogue is skilled in stakeholder management and public involvement. In addition to developing scoping and public involvement strategies for NEPA projects, his experience includes working with municipalities to develop MOU/MOAs, conflict resolution, NGO engagement/negotiation, and collaborating with U.S. Fish and Wildlife Service and/or regional conservation authorities in informal/formal ESA consultations.

SECTION 11

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