

# State Oil and Natural Gas Regulations Designed to Protect Water Resources



**Fourth Edition  
2023**



## Preface

This report was developed by the Ground Water Protection Council (GWPC) as an update to the 2014 and 2017 editions of the publication, “[\*State Oil and Natural Gas Regulations Designed to Protect Water Resources\*](#).”<sup>1</sup> The purpose of this and earlier studies, based on a review of 27 state oil and gas agencies, was to describe selected areas and related elements of state oil and gas regulations designed to protect water resources and to generally describe the rule language and agency approaches related to those areas. This update describes the considerable progress that agencies continue to make as they update their oil and gas regulatory programs.

The GWPC is the national association of state agencies that strive to protect and conserve our nation’s groundwater resources. The GWPC provides a forum for stakeholders including state, federal and local government officials, environmental non-governmental organizations, and representatives of the regulated industry to discuss emerging issues, technological advancements, the latest scientific research, recommended management practices, and regulatory responses to improve protection of groundwater resources.

State oil and gas regulators place great emphasis on protecting water resources from adverse impacts that can occur during oil and natural gas exploration and production (E&P) activities. The GWPC believes that regulation of oil and gas field activities is best managed at the state level where regional and local conditions and best applied practices are understood, and where regulations can be tailored to fit those conditions. While there are aspects of oil and gas regulation that occur at the local and federal government level, in the vast majority of instances the greatest experience, knowledge, and information necessary to regulate effectively resides with state regulatory agencies.

It is important to note that this review covers only state oil and gas agency regulations. We recognize there are states in which other agencies such as state environmental protection/resource conservation agencies or divisions, state health agencies, or other agencies may implement regulations that cover some of the elements listed. For example, in Alaska several elements such as pits, tanks, produced water transport; some types of waste disposal and spill management are regulated by the Alaska Department of Environmental Conservation and/or the Department of Transportation and/or other agencies rather than by the Alaska Oil and Gas Conservation Commission. There are also cases, such as in Ohio, where regulatory requirements are specified not only in the Ohio Administrative Code (rule) but also in the Ohio Revised Code (the legislative statute governing oil and gas activity). While we recognize these dichotomies of

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<sup>1</sup> Ground Water Protection Council, *State Oil and Natural Gas Regulations Designed to Protect Water Resources* (Apr. 2009, April 2014), available at <https://www.gwpc.org/research/>.

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regulation, this report does not attempt to capture all potential state regulatory structures for every element due to the multiplicity and variability of agencies across numerous states. Consequently, our review focuses on state oil and gas agency regulations (rules) only because these comprise the primary regulatory framework for managing oil and gas E&P in the majority of states. Although this report covers a significant portion of oil and gas regulation in the reviewed states, it cannot address all regulatory management scenarios. Therefore, the information in this report does not represent the full scope of state oil and gas regulation.

We would like to thank the following state oil and gas regulatory agencies for their assistance:

[Alabama State Oil and Gas Board](#)

[Alaska Oil and Gas Conservation Commission](#)

[Arkansas Oil and Gas Commission](#)

[California Department of Conservation, Geologic Energy Management Division](#)

[Colorado Oil and Gas Conservation Commission](#)

[Florida Department of Environmental Protection, Oil and Gas Program](#)

[Illinois Department of Natural Resources, Division of Oil and Gas](#)

[Indiana Department of Natural Resources, Division of Oil and Gas](#)

[Kansas Corporation Commission, Conservation Division](#)

[Kentucky Energy and Environment Cabinet, Division of Oil and Gas](#)

[Louisiana Department of Natural Resources, Office of Conservation](#)

[Michigan Department of Environment, Great Lakes and Energy, Office of Oil, Gas and Minerals](#)

[Mississippi State Oil and Gas Board](#)

[Montana Department of Natural Resources & Conservation, Board of Oil and Gas Conservation](#)

[Nebraska Oil and Gas Conservation Commission](#)

[New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division](#)

[New York Department of Environmental Conservation, Division of Mineral Resources](#)

[North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division](#)

[Ohio Department of Natural Resources, Division of Oil and Gas Resources](#)

[Oklahoma Corporation Commission, Oil and Gas Conservation Division](#)

[Pennsylvania Department of Environmental Protection, Office of Oil and Gas Management](#)

[South Dakota Department of Agriculture and Natural Resources, Minerals and Mining Program,  
Oil and Gas Section](#)

[Railroad Commission of Texas, Oil and Gas Division](#)

[Utah Department of Natural Resources, Division of Oil, Gas and Mining](#)

[Virginia Energy, Gas & Oil Division](#)

[West Virginia Department of Environmental Protection, Office of Oil and Gas](#)

[Wyoming Oil and Gas Conservation Commission](#)

The views expressed in this report, as well as any suggested “Considerations,” are those of the GWPC, in general, and do not necessarily reflect those of any particular state. Further, the considerations in this report should not be construed as offering “Best Practices,” as each situation is different and a uniform practice for any element may not be appropriate or desirable in every case. Any errors or omissions concerning state rules or procedures are the responsibility of the GWPC and not an individual state. State regulatory programs are significantly more detailed and comprehensive than could possibly be represented in this summary report. Consequently, we strongly recommend the reader contact individual state oil and gas agencies to obtain information about specific state oil and gas requirements. We hope you will find this report informative and useful.



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## Chapter 1: Report Summary



**Figure 1-1 Typical rotary drilling operation- Source, Southwestern Energy**

**A**lthough current uncertainties in the fossil energy sector exist, there was an overall increase in activity over the past two years. Also, the emphasis on improved groundwater protection laws and regulations governing oil and natural gas production has continued. It is critical to maintain comprehensive and effective regulations. State regulatory strategies differ in response to unique local circumstances and characteristics. Over time, they evolve to address public concerns about the safety and environmental impact of oil and gas development, as well as rapidly changing technologies, new field discoveries, revised leading operational practices, internal and external reviews, and regulatory experience.

The GWPC prepared this report to help equip regulators and policymakers with pertinent data and observations to consider when evaluating and revising rules in their agencies. It includes an overview of regulations in 27 state oil and gas agencies as of January 1, 2021, a discussion of how rules have evolved since the previous review, and considerations for regulators and policymakers derived from leading practices adopted or proposed in various agencies.

The report also builds on previous discussions of several emerging issues that merit more detailed consideration in future state regulatory evaluations. With regard to alternate use of produced water, for example, these include continued investigation into the near-term feasibility of alternative disposal options (like evaporation) and technical and regulatory advancements that support expansion of in-field recycling by the oil and gas industry. Other significant issues related to groundwater protection include: wellpad construction, stormwater management, annular pressure monitoring, well and surface facility legacy issues, reuse of produced water, both within and outside of oil and gas operations, and spill management and cleanup.

This report highlights several practices adopted by oil and gas regulating agencies to enhance transparency, efficiency, and effectiveness in regulatory implementation. Successful groundwater protection requires not only an appropriate framework of laws and rules, but also sound regulatory practices and programs. State agencies use programmatic tools and documents to promote consistent implementation, coordination, enforcement, and documentation of state rules. These include tools such as forms, formal and informal guidance, policies and procedures, and data management systems like the Risk Based Data Management System (RBDMS)

developed on behalf of state agencies by the GWPC. Although this report will discuss some associated elements of regulation such as data management, the primary thrust of the report is promulgated regulations (rules). The complexities of covering the myriad policies and procedures developed by state agencies would require a more comprehensive evaluation.

Since the 2017 report, agencies have made measurable progress in some of the areas tracked by this report. As oil and gas E&P has been developed around the country and especially in areas where unconventional resources are present, the public has expressed concern about the safety and environmental impact of oil and gas development. Oil and gas agencies address these concerns by proactively conducting internal reviews and updating their regulations to respond to changes in technology and practices. Some notable updates include requirements for management of hydraulic fracturing operations, chemical disclosure of hydraulic fracturing fluids, enhancements to mechanical integrity (MI) testing, improved pit siting and lining requirements, and advances in data management. States also use external program reviews conducted by 3<sup>rd</sup> party organizations to evaluate their current regulations and provide suggestions for revision. When agencies update their rules, consideration is often given to focusing on areas that will increase protection for water resources including issues covered here such as well integrity, surface fluid management, and cleanup standards for spills. Interagency and interstate coordination of activity is also increasingly critical, alongside the need for data integration between disparate data systems, which will lead to better data analysis capability and increase transparency.

Overall, state oil and natural gas regulatory agencies are diligent in addressing the technological, legal, and practical changes that occur in oil and gas E&P. By employing highly trained, experienced staff and implementing rules designed to protect water resources, agencies show their commitment to continuous improvement with an aim toward assuring water availability and sustainability.

## State Regulations Highlights and Considerations

**S**tate oil and gas regulatory frameworks related to groundwater protection are evolving steadily. The state of play in oil and gas regulation covers numerous areas of interest. Each of these areas contains specific elements that typify the current status of regulatory management as of January 1, 2021.

### Permitting

All 27 oil and gas agencies require permits for the drilling, and operation of oil and gas related wells. Twenty-six also require a permit to re-drill or deepen an existing well and 22 require a permit for well workovers. Fewer oil and gas agencies (eight) require a separate permit to construct a well pad and (six) require a permit for stormwater management on a wellsite. However, regulators often consider well pad construction activities and stormwater management during the process of reviewing the drilling permit, and some agencies even require pre-drill site inspections that can be used to evaluate potential specific site construction and stormwater management activities.

#### *Considerations:*

- For states where topography, weather patterns, or other factors pose challenges for well pad construction, requirements that mitigate those issues.

### Hydraulic Fracturing

Perhaps the most significant trend in the area of hydraulic fracturing relates to the notice requirements prior to conducting hydraulic fracturing operations. In 2014 only six agencies had a notification requirement for this activity. By January 1, 2016, the number had risen to 15. As of this report 16 agencies require prior notice. This represents a substantial increase between 2014 and January 2021. There was also a significant increase in the number of agencies requiring adjacent water well testing (from four to twelve between 2014 and 2021).

#### *Considerations:*

- Mechanical Integrity Testing requirements prior to well stimulation;
- Monitoring and reporting requirements during well stimulation, and suspension of well stimulation when mechanical or formation integrity is compromised;
- Analysis of confining zone(s) and “Area of Review” style analysis of near wellbore geology to mitigate risk of conduits transmitting hydraulic fracturing fluids;
- Defining the meaning of simultaneous operations (SimOPS) relative to hydraulic fracturing; and
- Reporting volumes of water used by type (e.g., Produced water, groundwater, fresh water etc...).

## Well Integrity

Providing assurances that wells will not provide critical flow pathways for the migration of fluids or gases from downhole to the surface or into groundwater is of paramount importance. Proper well construction and evaluation techniques can demonstrate the effectiveness of the well in preventing migration. One of the most critical well construction phases is the proper setting and cementing of the surface casing string. Twenty-six of the agencies reviewed specify the setting of surface casing below the deepest protected groundwater zone. One agency uses a table that specifies the surface casing setting depth based on the total depth of the well. It was not possible to determine from the regulation whether or not this would result in setting surface casing below the deepest protected groundwater. Regardless, all 27 agencies specify bottom to top cementing; although one agency provided for such cementing based on downhole specific conditions. Thirteen agencies require surface casing to be pressure tested prior to drill out and eight require the use of casing centralizers on the surface casing string. With respect to general casing standards, 14 agencies have specific standards including nine that require the use of API standards for casing and seven with standards on the use of used or re-conditioned casing.

### *Considerations:*

None of the policies above are universally applied. Regardless, additional aspects of well integrity for wider consideration might include:

- Comprehensive well integrity testing during construction, especially Formation Integrity Testing (or “shoe” testing) prior to drill out;
- Centralization standards for production/long string;
- Isolation of flow zones capable of over-pressurizing an annulus and corrosive zones
- Providing standards for reconditioned casing;
- Specifying mix-water quality standards and requirements for free water content in cement;
- Reporting of “kicks” during drilling to ensure well control oversight and to establish a better understanding of potential over-pressurized zones; and
- Standards for annular space minimums between casing strings and between strings and formation

## Temporary Abandonment

Twenty-six agencies allow operators to temporarily abandon (TA) or idle wells with 22 of these requiring a prior authorization before a well can be placed in TA status. Twenty-six agencies also allow temporary abandonment status to be extended beyond an initial time period and 17 require either a casing pressure test or specific well construction before the TA period can be extended. Fifteen agencies place a total limit on the time a well may remain in TA status.

*Consideration:*

- Monitoring of wells in TA status to ensure they maintain mechanical integrity; and
- Establishing a maximum time duration within which a well may remain in TA status.

### **Production Operations**

There are three specific aspects of operations reviewed for this report. All three are related to monitoring or inspections by the operator of particular elements. The first is the monitoring of the bradenhead fitting on wells to look for changes in pressure which might indicate a loss of integrity. As of this review, seven agencies require operators to monitor the bradenhead (an increase of 43 percent since 2017). The second is the inspection of piping, valves, and flowlines to look for signs of leakage. Six agencies require these types of operator inspections (an increase of 33 percent since 2017). The last element reviewed was a requirement for inspections of other appurtenances such as tanks, well heater/treaters, oil/water separators and similar equipment. The purpose of these inspections as with inspections of piping, valves and flowlines is to look for signs of failure or leakage. As of January 1, 2021, six agencies require this type of operator inspection (an increase of 50 percent since 2017).

*Consideration:*

- Bradenhead monitoring requirements to facilitate lifetime well integrity management; and
- Requirements for operator inspections of piping, valves, flow lines and other appurtenances during operations.

### **Storage in Pits**

Although pits are used for a number of different purposes, this report focuses on the most commonly used pits (drilling and produced water storage). The elements reviewed for these pits are related to their construction, operation, monitoring, and closure. As of this report, 25 agencies had specific requirements concerning drilling pits while 19 agencies regulated produced water storage pits, including four agencies that banned the use of such pits. Six agencies also had separate regulations governing the use of centralized storage pits. With respect to requiring a prior authorization to construct and operate pits, 15 agencies require such authorizations for drilling pits while 19 require prior authorization for produced water storage pits. In ten agencies drilling pits require a siting setback from surface water with 11 agencies limiting the siting of drilling and produced water storage pits within the 100-year floodplain or in a floodway. Certain construction requirements varied depending upon pit type. For example, 14 agencies require a liner for drilling pits and 18 agencies require a liner for produced water storage pits. Fifteen agencies also specify liner competency standards for both types of pits (an increase of 13 percent since 2017). Regarding the duration of use, 20 agencies have a usage time limit for drilling pits and 13 limit the usage time for produced water storage pits. Finally, 12 agencies specify that upon closure the site must be returned to its condition prior to use for drilling pits while eight have the same specification for produced water storage pits.

*Considerations:*

- Requirements for siting, design, construction, operations, and closure of pits;
- Competency standards for liners;
- Inspections prior to use and during operations; and
- Leak detection requirements.

### **Storage in Tanks**

As with previous reports the regulation of above ground storage tanks is limited and remains an area of concern. However, as of this report six agencies require a prior authorization to construct and operate tanks (an increase of 66 percent since 2017) and seven had some design and construction standards for tanks. Further, seven agencies have some siting or setback requirements (an increase of 29 percent since 2017). On another positive note the number of agencies requiring a secondary containment system for tanks increased from 17 to 22 between 2017 and 2021, with 18 of these requiring ongoing inspections of the containment area.

*Considerations:*

- Requirements should address siting, design, construction, operations, and closure of tanks; and
- Tank material compatible with stored fluids.

### **Well Plugging**

The effective plugging of oil and gas wells is critically important to the protection of groundwater. Plugging involves the placement of cement and other materials at strategic locations in a manner designed to prevent the migration of fluids and gases from producing or injection zones into protected groundwater zones. In this regard 24 of the agencies reviewed require placement of cement plugs above producing formations and 19 also require the placement of cement plugs across all protected groundwater zones. The combination of production zone plugs, and groundwater plugs ensures that protected groundwater is isolated from deeper production or injection zones. Further, 21 agencies require the submission of a plugging plan prior to plugging so that the agency can evaluate the proposed plugging details for adequacy and to assure they meet regulatory requirements. Finally, all 27 agencies require operators to submit a post plugging report for agency review.

*Consideration:*

- Cement placement across all protected water zones;
- Witnessing of well plugging operations by agency representatives; and
- Tagging of plugs where needed to assure proper placement.

## Transportation of Produced Water for Disposal by Truck or Pipeline

The transportation of produced water is one of the regulatory elements reviewed that is sometimes regulated by multiple agencies within state government. As a consequence, the number of oil and gas agencies regulating transportation practices does not reflect the totality of regulatory control. That said, the review of oil and gas agency regulations indicates that 11 oil and gas agencies require a prior authorization for the transport of produced water. Four agencies regulate pipeline transport while nine regulate truck transport. Regardless of the transportation method, 13 agencies require operators to utilize manifests or trip tickets to track the movement of produced water (an increase of 23 percent since 2017). Additionally, 16 agencies also require operators to report the final disposition of produced water (an increase of 19 percent since 2017).

### *Considerations:*

- Permitting or licensing of produced water transporters and the recording of produced water volumes transported off-site; and
- Tracking and reporting of final disposition.

## Produced Water Reuse for Oil & Gas E&P

The reuse of produced water in the oilfield has continually increased over the past decade. The bulk of this reuse can be attributed to the use of produced water as a carrier fluid for high volume horizontal hydraulic fracturing. In the latest update of figures commissioned by the GWPC (2017), beneficial reuse of produced water for oil and gas operations (other than enhanced recovery) remained small at about 1.4 percent.<sup>2</sup> Regardless, this is more than twice the amount used in oil and gas operations in 2015. Also, there are new regulations being adopted such as one in New Mexico that regulates the transfer of water from the oilfield to outside, non-oilfield uses. However, it is only in the past few years that produced water with higher levels of Total Dissolved Solids (TDS) has been acceptable in the hydraulic fracturing process. Further, the volumes of water being used for high volume hydraulic fracturing have grown significantly. Consequently, the total volumes of produced water re-used in the oilfield is likely to continue to grow and contribute to greater overall beneficial reuse in the coming years provided the upward trend in the use of hydraulic fracturing using large water volumes continues. Although using produced water in the drilling of oil and gas wells is a customary practice, certain restrictions on this use have been gaining traction. For example, the review of agency regulations indicates that 11 agencies prohibit the use of produced water during the drilling of the surface casing portion of a well to protect groundwater resources.

### *Considerations:*

- Chemical characterization and management of side streams;

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<sup>2</sup> Veil, John U.S. Produced Water Volumes and Management Practices in 2017, GWPC, February 2020, 137 pp., [https://www.gwpc.org/sites/gwpc/uploads/documents/publications/pw\\_report\\_2017\\_final.pdf](https://www.gwpc.org/sites/gwpc/uploads/documents/publications/pw_report_2017_final.pdf)

- Regulation of use of produced water for uses in the oilfield other than well stimulation; and
- Siting, design, construction, operations, and closure standards for produced water pipelines.

### **Exempt Waste Disposition**

Similar to produced water transport, the management of exempt waste is often regulated by multiple agencies within a state. In 21 states, the oil and gas agency has some regulatory control over on-site disposal of exempt waste, and 15 oil and gas agencies regulate land or road application of produced water (an increase of 20 percent since 2017). Eleven agencies regulate the application of tank bottoms to roads or lands. Eight agencies prohibit the land application of produced water, and six prohibit land application of tank bottoms.

#### *Consideration:*

- Manifests for off-site disposal where appropriate.

### **Spill Response**

The management of spills from oilfield operations also commonly utilizes a multi-agency approach. For example, response to a spill may involve multiple agencies depending upon several factors including the location, nature, volume, and media affected by a spill. Twenty-five oil and gas agencies require some spills to be initially reported to the agency, though 19 agencies have a volume threshold for reporting. Twenty-three agencies also require a detailed follow-up notice be submitted to the agency within a specified time. Twenty-three oil and gas agencies also have spill remediation jurisdiction, and 13 have some quantifiable cleanup standards. (an increase of 23 percent since 2017).

#### *Considerations:*

- Clean-up standards that are measurable and appropriate for the characteristics of the material spilled and the media impacted; and
- Follow up notification details to improve performance.

## Chapter 2: Background, Purpose, and Scope

### Background

**A**s stated in previous reports, regulating is the process used to manage an activity under the authority of a law or rule and consists of two principal parts: rules and programs. Rules are the set of instructions or requirements that govern an activity. Programs are the means by which these instructions or requirements are enforced. The boxes below describe how rules and programs are linked to create the regulatory framework.

#### **Rules**

Rules can be either prescriptive or proscriptive. Prescriptive rules define what must be done while proscriptive rules define what must not be done. For example, a prescriptive rule might read “The operator shall install a ¼-inch NPT fitting on the casing tubing annulus of each Class II well,” while a proscriptive rule might say “Pits shall not be located within the boundary of the 100 year flood zone.” Rules can also be performance based or descriptive in type. For example, a performance based rule might say “The operator must use an amount of cement sufficient to protect all fresh groundwater zones,” while a descriptive rule might say “The operator must use an amount of cement calculated to circulate to the surface behind the casing plus a 10 percent overage.” Each type of rule plays a key role in the regulatory process. Performance based rules allow the regulatory agency and the regulated community to define requirements based on site-specific conditions. As such they can often provide a more appropriate response to a unique set of conditions. Descriptive rules are less flexible but do not require as much interpretation and, as such, tend to be easier to follow.

#### **Programs**

In state oil and gas programs, application of the rules is typically overseen by a governing body such as a commission, board, or division. In some cases, these bodies consist of people appointed by the governor of a state, while in other cases independently elected commissioners or board members may have the authority to apply the regulations. Day-to-day operations are typically run by an oil and gas agency (division) that includes directors, managers, geologists, engineers, technicians, field inspectors, administrative staff, and legal staff. The staff is charged with the responsibility of ensuring the regulated community is following state rules. Regulatory agencies accomplish this by conducting administrative and technical reviews of permit applications, witnessing field operations, performing field inspections, conducting meetings and hearings and, where necessary, taking formal enforcement action to achieve compliance.



the 2009 and 2014 reports. This does not indicate agencies are lowering their regulatory requirements but rather, that the elements were more stringently reviewed. This is important because there are several elements where, even using the stricter review standard, the numbers increased. This indicates an even greater change in oil and gas regulation than would otherwise have been indicated. Another meaningful change in methodology was in the way many of the elements were worded. In the 2014 review a number of elements were measured against whether or not an agency “allowed” a practice. For the 2017 edition of the report a practice was not counted as allowed unless the agency had specific rules related to the use of the practice. This change was made to avoid the inference that a practice would automatically be allowed unless an agency prohibited it, and this resulted in numerous instances where an item would have been counted in 2014 but not in the 2017 report. All of these changes in methodology were carried forward into this 2021 report. Further, some elements were insufficiently detailed to allow for a useful evaluation. For example, the 2014 element “Does the rule place a limitation on the constituents of drilling fluid” was modified in 2017 to become “Does the rule place a limitation on the constituents of drilling fluids for surface casing,” and expanded to include sub-elements as to whether or not the agency prohibited the use of oil based or produced water based drilling fluids. Because of the changes in review methodology such as those noted above, it was not possible to compare the numbers in the 2017 report to previous reports. However, the 2021 report contains numerous comparisons between specific element numbers from 2017 to 2021.

Discussion drafts, thought pieces, outside proposals submitted to agencies, and other non-official regulatory documents were not included in the study.

Appendix 4 shows the matrix of regulatory areas and related elements reviewed for this update. For some elements, this report presents comparisons between the 2017 and 2021 findings.

As with the 2009, 2014, and 2017 reports, each state’s rules were compared to the elements within each regulatory area. A determination was made as to whether or not the state had a rule that addressed the element or elements. As noted previously, however, the evaluation criteria were modified to provide for a stricter interpretation of the rules in order to minimize subjectivity. After each state’s rules were evaluated, the state was given an opportunity to review and comment on the findings and to provide updated information concerning their rules.

### **Comparison of Regulatory Areas Used in the 2009, 2014, 2017, and current reports**

In conducting this update, GWPC used the same regulatory areas as the 2017 report to facilitate comparisons (Table 3-1).

2009 Areas	2014 Areas	2017 Areas	2021 Areas
Permitting	Permitting	Well and wellsite permitting	Well and wellsite permitting
Well construction	Well integrity	Well integrity	Well integrity
Hydraulic fracturing	Formation treatment, stimulation, or fracturing	Hydraulic fracturing	Hydraulic fracturing
	Production operations	Production operations	Production operations
Temporary abandonment	Temporary abandonment	Temporary abandonment	Temporary abandonment
Well plugging	Well plugging	Well plugging	Well plugging
Pits	Storage in pits	Storage in pits	Storage in pits
Tanks	Storage in tanks	Storage in tanks	Storage in tanks
	Transportation of produced water for disposal	Transportation of produced water by truck or pipeline for disposal	Transportation of produced water by truck or pipeline for disposal
	Produced water recycling and re-use	Produced water reuse for oil & gas E&P	Produced water reuse for oil & gas E&P
Waste handling and spills	Exempt waste disposal	Exempt waste disposition	Exempt waste disposition
	Spill response	Spill response	Spill response

Table 3-1 Areas Reviewed from 2009 to January 2016

Definitions of “protected groundwater” differ across the agencies surveyed, complicating the evaluation of state oil and gas rules, and preventing the use of a single precise term, such as Underground Source of Drinking Water (USDW), throughout this report. Therefore, this report uses the generic term “groundwater,” defined as “*water contained in geologic media which has been designated by a state as usable for domestic, industrial or municipal purposes or which is otherwise protected by state regulation.*” Differing state definitions of protected groundwater were the subject of a companion report published by the GWPC<sup>4</sup>.

Finally, this update highlights emerging issues in the field of oil and gas regulation and discusses several topics critical to understanding a wider spectrum of state efforts to protect groundwater.

<sup>4</sup> Musick, Stephen P., Overview of Groundwater Protection Regulations in Oil and Gas States, GWPC, April 2014 PP. 11

It concludes with considerations for regulators, policymakers, and researchers, summarizing ideas on today's leading practices from agencies around the country related to issues agencies are likely to encounter in the near future.

### Exclusions

In addition to state oil and gas agencies, other local, state, and federal agencies may exercise significant control over oil and gas activities. Time and resource constraints do not allow this report to account for interactions between the oil and gas agency and other local, state, and federal regulatory agencies, nor to catalog relevant regulations of these other agencies. Many of these agencies operate under a Memorandum of Agreement (MOA) or Understanding (MOU) with the state oil and gas agency to define jurisdictional boundaries. For example, the Railroad Commission of Texas has an MOU with the Texas Commission on Environmental Quality (TCEQ) relative to the intersections of agency jurisdiction (Appendix 8). Such agreements are commonplace in many agencies and reflect a coordinated approach designed to increase environmental protection and emergency response. In some western states agencies, the Bureau of Land Management (BLM) exercises substantial control over oil and gas E&P activities where the federal government or a tribal government is the primary landowner or mineral rights holder. In some cases, the state will defer to the BLM while in other cases there is a dual layer of regulatory control. In a 2012 survey of state oil and gas agencies, the GWPC found that 13 of 15 agencies issued a separate state permit for oil and gas wells on federal land.<sup>5</sup> (Appendix 7) In such cases it is not uncommon for the state and BLM to have an MOA or MOU. In some agencies there is a basic jurisdictional split between state agencies relative to the regulation of oil and gas activities. While uncommon, this type of jurisdictional split makes a complete understanding of all aspects of oil and gas regulation throughout the country more complex and challenging.

As with the previous versions of this report, Underground Injection Control (UIC) programs were not reviewed for this update. UIC regulation was excluded because on-site reviews of such programs are already conducted by the GWPC under the Class II UIC Peer Review process. Consequently, while the UIC program is discussed in the report as a produced water disposal method, this study does not address UIC-related issues such as induced seismicity and a comprehensive review of the UIC regulations and programs was not conducted<sup>6</sup>.

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<sup>5</sup> Survey of States Regarding Permitting on Federal Land, GWPC, 2012

<sup>6</sup> <https://www.gwpc.org/research/>

## Chapter 3: Evolution of Oil and Gas Regulation



**Figure 3-1 Source,  
Unknown**

The evolution of water and environmental resource protection regulations governing oil and gas exploration, production, and well abandonment “upstream” activities did not follow the same pattern as other waste-producing industries, including those related to oil refining and other “downstream” petroleum operations. Controls for preventing damage to air, water, land, and hydrocarbon resources from “downstream” operations were primarily developed in response to a series of federal pollution control acts passed by Congress between 1972 and 1990. In contrast, water protection measures related to the “upstream” (production) sector of the petroleum industry, covered in this study, were initiated much earlier in response to individual state statutes and regulations enacted after 1900.

A historical perspective reveals how, over time, state legislative bodies responded to increasing concerns by landowners, farmers, and municipal officials that oil field practices were contaminating water and land resources. It also shows how state oil and gas environmental regulations have been philosophically influenced by the influx of federal environmental laws during the past forty-five years in some ways, but not in others.

### Looking Forward: Drivers of Regulatory Development

State regulation of oil and natural gas E&P activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the state regulatory process. Regulation of oil and gas field activities is managed best at the level where regional and local conditions are understood and where rules can be tailored to fit the needs of the local environment. While some oil and gas production regulation does occur at the local and federal governmental level, on most issues the greatest experience, knowledge, and information necessary to regulate effectively rests with state regulatory agencies.

As captured in the first three versions of this report, state legislators and regulatory agencies from coast to coast have continued to write new laws, finalize, and propose regulations, and modify existing regulatory practices and programs to address pressing concerns of industry and the public alike. As this updated report documents, there has been continuous and significant regulatory improvement by state oil and gas agencies across the country over the past four years. As efforts increase to bring regulations up to date with rapidly changing technologies and other

regulatory drivers continue to directly impact the industry, growth and change to state oil and gas regulatory programs is likely to continue. But what are the factors that drive the state regulatory update process?

Factors driving changes to rules and state regulatory programs include regulatory experience, routine internal review of existing rules, technological updates, public input, new field discoveries, revised best management practices, and internal and external reviews. To assure regulations are implemented as designed, some agencies like the Railroad Commission of Texas maintain online manuals (<https://www.rrc.state.tx.us/oil-and-gas/publications-and-notices/manuals/>) to assist operators with regulatory compliance. In Texas these include an Oil and Gas Procedure Manual, a manual on Injection Storage and a manual on Surface Waste Management which contains specifications for water protection relative to oil and gas operations including:

- A list of applicable rules such as:
  - Statewide Rule 8: Water Protection<sup>7</sup>;
  - Statewide Rule 91: Cleanup of Soil Contaminated by a Crude Oil Spill; and
  - 16 Texas Administrative Code Chapter 4, Subchapter F, Oil and Gas NORM

Regulatory experience and activity is one of the primary drivers of regulatory reform. Based on the knowledge of past problems and investigative findings, regulatory agencies will often define new boundaries for regulatory management. A review of the history of oil and gas activity can be used to evaluate the effectiveness of current regulation and to provide the basis for regulatory change. For example, although Texas banned them in 1969, in the 1970s the use of evaporation pits was still not an uncommon practice. As evidence of shallow subsurface groundwater contamination near such pits became evident, there was a call for more stringent regulation. This led to the banning of evaporation pits in some agencies and the lining of these pits elsewhere.

The public has also played a significant role in the development of regulations. By providing input on proposed rules, the public has affected the regulatory development process in a meaningful and direct way.

External reviews of state programs conducted by organizations such as IOGCC and GWPC are also a part of the regulatory review process.

Further, efforts to develop best management practices, technical guidance, and model frameworks such as those undertaken by organizations like the API, EDF, and others have led to improvements in regulatory programs resulting in increased environmental protection. For

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<sup>7</sup> Summary of Statewide Rule 8, <https://www.rrc.state.tx.us/oil-and-gas/publications-and-notices/manuals/surface-waste-management-manual/swr8-summary/>

example, the GWPC and the IOGCC facilitate multi-state collaboration and innovative regulatory solutions for oil and natural gas producing states.” As member organizations of state governments, the GWPC and IOGCC are in the unique position to coordinate efforts between the federal government and states to ensure that advances in regulatory regimes are efficient and effective. GWPC and IOGCC have each (and in partnership) published several reports related to oil and gas exploration and production regulation including a 2021 updated version of a report on Potential Induced Seismicity.<sup>8</sup>

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<sup>8</sup> Potential Induced Seismicity: A Resource of Technical & Regulatory Considerations Associated with Fluid Injection, [https://www.gwpc.org/wp-content/uploads/2022/12/FINAL\\_Induced\\_Seismicity\\_2021\\_Guide\\_33021.pdf](https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf)

## Chapter 4: Oil and Gas Regulations

**A**s previously noted, this report includes a review of state oil and gas regulations in areas such as permitting, hydraulic fracturing, well integrity, plugging, and others. The following represents the findings for each of the areas and related elements listed in Appendix 4.

### Permitting

Permitting is the process of authorizing the drilling and completion of a well for oil and gas purposes and other activities associated with oil and gas E&P. It includes a regulatory review of information concerning well locations, depths, proposed construction, applicant status, financial assurance, and many other things.

A person or company must submit an application to the regulatory authority and receive an authorization before drilling can begin. Permitting of wells serves many purposes. First, it expresses the intent to drill a well for the extraction of oil or gas and provides the applicant's drilling plan. Second, the permit application provides the regulatory agency with information such as the location, proposed depth, target formations, and proposed construction of the well. In some agencies, well construction plans are reviewed and approved through other processes subsequent to issuance of a drilling permit; however, all agencies evaluate proposed construction plans before drilling commences. Based on this information, the regulatory agency can evaluate the proposed well to determine whether it meets the current regulatory requirements for drilling, construction, and operation. In some agencies, the permit covers not only the drilling of the well but other activities including well treatment, hydraulic fracturing stimulation, storm water management, the construction of the wellsite, excavation of pits, and authority to plug a drilled dry hole. For example, in Arkansas, the applicant is also required to submit a lease facility plan, including pit construction specifications. The Arkansas Oil Conservation Commission must approve lease facility plans before drilling can begin. The Oil and Gas Commission and the Division of Environmental Quality, both now part of the Arkansas Department of Energy and Environment, have joint enforcement of specific provisions of this rule requirement. Other states may authorize such activities through a series of permits.

Authority to require permits for the drilling of oil, gas, and service wells (injection wells and others) is usually delegated by the state legislature to an oil and gas division, commission, or board. Although sometime elected, heads of commissions or oil and gas agencies are typically appointed by either an agency head or by a governor and they are often geologists, engineers, or attorneys. Staffs usually include engineers, geologists, or environmental scientists with technical

training and qualified to review applications for both conservation and water resource protection purposes.

Permits constitute a license issued by the state to conduct an activity. Regardless of the activity authorized by the permit, the permit holder must otherwise have a legal right to conduct the activity. With respect to oil and gas operations this right is usually specified in a lease, which details the rights and responsibilities of the mineral rights owner and the oil and gas operator.

All 27 oil and gas producing agencies in the study have permitting requirements governing the locating, drilling, completion, and operation of oil and gas related wells.

### Scope of Permitting Review

This study reviewed state permitting requirements with respect to nine types of permits/authorizations (Table 4-1)

Permit Type	Includes:
Drilling	Permits to drill new oil or gas related wells.
Deepening/ redrilling	Permits to deepen an existing well or drill out a plugged well.
Workover	Permits to conduct a workover on an existing well.
Wellpad construction	Permits to develop the wellsite including pad construction and equipment placement.
Stormwater management	Permits to construct well-sites and surface facilities for the purpose of preventing stormwater runoff during drilling operations.
Hydraulic fracturing	Permits to hydraulically fracture a new or existing oil or gas well.
Temporary abandonment	Prior authorization to temporarily abandon or shut-in a well.
Pits (Drilling and produced water storage)	Prior authorizations to construct and operate various types of pits.
Storage tanks	Prior authorizations to construct and operate above ground oil and produced water storage tanks.

**Table 4-1 Permit Types**

*NOTE: Plugging permits; which was a Permit Type listed in the 2014 report, were not included in the 2017 report or this report because the vast majority of agencies do not issue a separate permit for this activity. However, all 27 states require a prior notice of intent to plug and 21 require submission of a plugging plan to the agency.*

### January 2021 Findings

A review of state regulations relative to permitting indicates all 27 agencies require a permit for the drilling, re-drilling, or deepening of an oil or gas related well, while 22 also require a permit

to workover an existing well. For the 2017 and 2021 editions of the report an additional category was included (Stormwater management). As of January 2021, six agencies require a permit for onsite-stormwater management. Eight agencies also require a permit for wellpad construction. In addition to wells and wellsites, agencies also issue permits and prior authorizations for other oil and gas activities. For example, 13 agencies issue permits or require authorizations for hydraulic fracturing and 22 require a separate authorization to temporarily abandon a well. With respect to pits 15 agencies require a permit or prior authorization to construct and operate a drilling pit while 19 have prior authorization requirements for fluid storage pits. These figures represent increases from the 2017 report in every category. Figure 4-1 shows the number of agencies with permitting requirements for specific well drilling and wellsite activities in 2021.

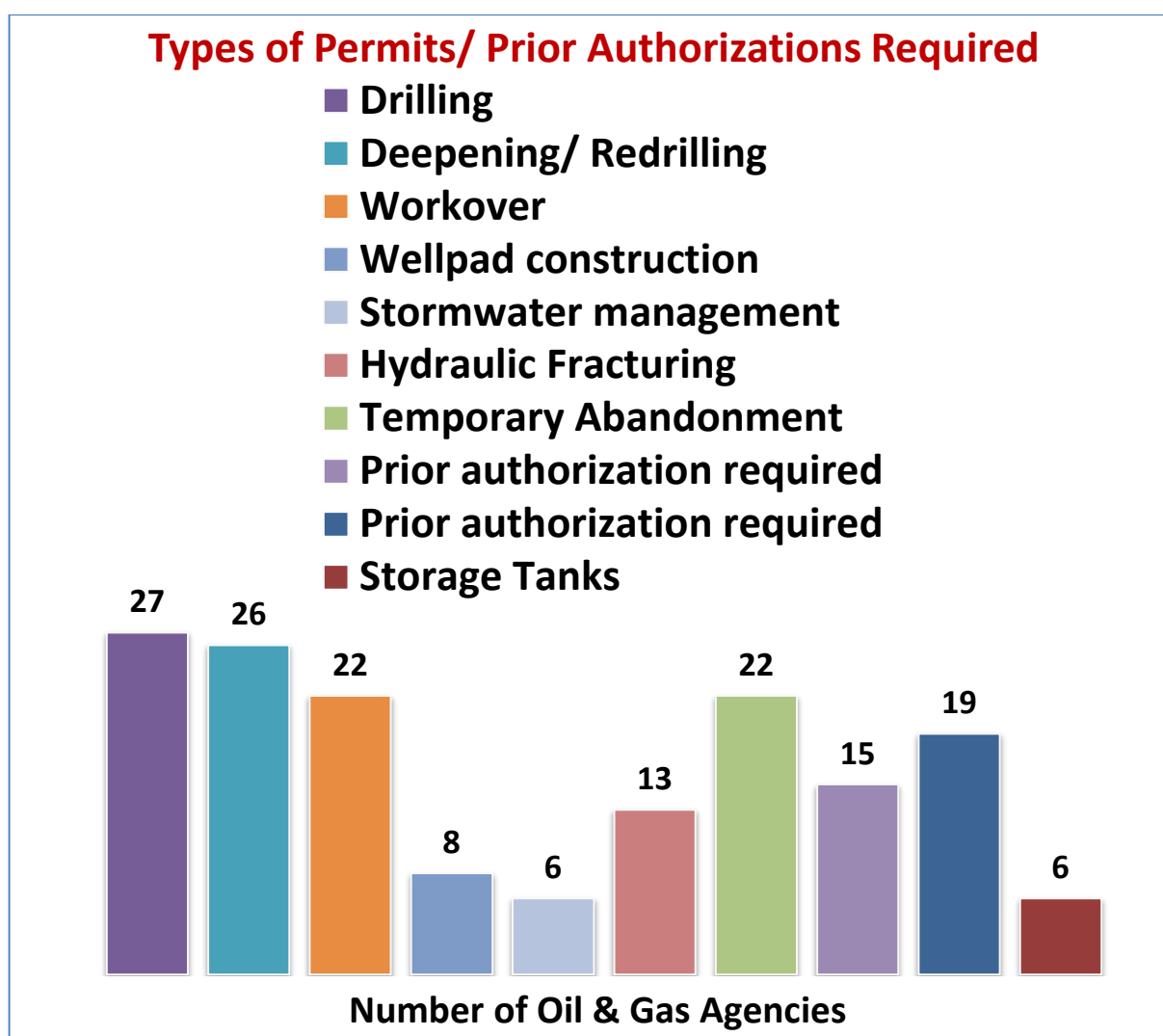


Figure 4-1

With respect to permit management, 22 agencies have regulations with provisions that allow the agency to delay or deny a drilling permit if the applicant is not in compliance with the regulations (a 10percent increase since 2017). Eighteen agencies may suspend, or revoke permits for non-compliance (Figure 4-2). It should be noted that regardless of regulatory language most, if not all, agencies have some authority to deny, delay or suspend a permit for cause.

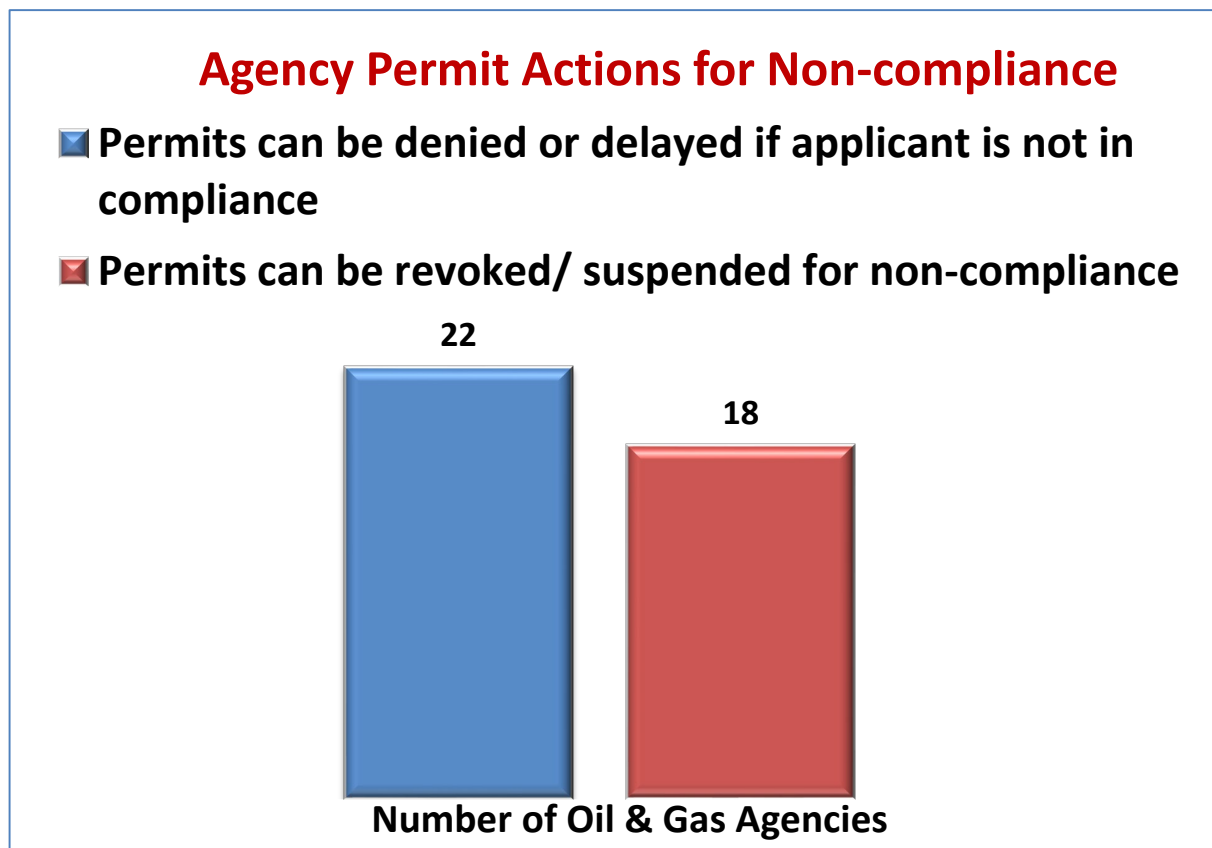


Figure 4-2

## Hydraulic Fracturing

Well treatments fall into two primary categories:

- **Matrix treatments:** Matrix treatments are usually performed below reservoir fracture pressure and are designed to restore the natural permeability of the reservoir following damage to the rock that can occur as a consequence of the drilling, casing, and cementing process. Applying acid to the face of the formation below fracture pressure, or “acidizing,” is a typical matrix treatment.

- **Hydraulic fracturing treatments:** Hydraulic fracturing is a process designed to create artificial fractures in the formation that increase the surface area of drainage and create greater conductive flow between the reservoir and the wellbore.

As in 2017, this report will focus on hydraulic fracturing treatments. Although matrix treatments are important in the development of oil and gas resources, their typically low pressure and less complex chemical makeup result in a lower hazard profile than hydraulic fracturing. Therefore, most agencies have focused their regulatory revisions primarily on hydraulic fracturing.

### Matrix Treatments

Matrix treatments, such as acid jobs, are near-wellbore processes designed to remove near-well formation damage introduced during the drilling process by pumping acid through casing into the producing zone below pressures that would be necessary to create or propagate fractures. The process is designed to improve production by increasing the effective radius of the well. In some cases, typically in carbonate formations such as limestone, an acid fracturing process is performed above the fracture pressure of the formation. The process etches the surface of fractures and allows for a higher conductivity pathway from the reservoir to the wellbore. The mixture typically used for this process is a 15 percent to 18 percent solution of acids that include hydrochloric acid sometimes mixed with acetic, formic, fluoroboric, and other acids. Because matrix treatments do not typically involve high pressures or volumes of additives and are thus considered lower risk, this study did not evaluate state rules governing these types of processes.

### Hydraulic Fracturing Treatments



Figure 4-3 Source,  
FracFocus

Hydraulic fracturing is a critical component of well development because without it, there may be insufficient flow pathways for oil or gas to get to the wellbore. The process involves pumping fluid into a formation under sufficient pressure to create fractures in the rock matrix, allowing oil or gas to flow through the fractures more freely to the wellbore. By creating new pathways, hydraulic fracturing can exponentially increase oil and gas flow to the well, resulting in increased production ratios vs. non-fractured wells.

Between 2000 and 2015 this change in ratio resulted in a significant increase in the amount of oil and gas production where hydraulic fracturing is used. For example, the U.S. Energy Information Administration reported that in 2000 6.14 trillion cubic feet (tcf) of natural gas came from tight shale formations. By 2020 the natural

gas production from tight shale formations had risen to 29.6 tcf.<sup>9</sup> While this change can be attributed to many factors, two primary factors are the advances in horizontal drilling technology and the widespread use of high volume hydraulic fracturing.

The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas occurred in either the Hugoton field of Kansas in 1946 or near Duncan, Oklahoma, in 1949. In the ensuing 60 plus years, hydraulic fracturing has become a routine technology that is frequently used in the completion of gas wells, especially those drilled into unconventional reservoirs such as tight shale. In a paper written for the Society of Petroleum Engineers it was estimated that, since 1949, more than 2.5 million fracture jobs have been conducted on oil and gas wells worldwide.<sup>10</sup> According to the U.S. Energy Information Administration (EIA), 69 percent of all new oil and natural gas wells drilled in the U.S. are hydraulically fractured and horizontally drilled.<sup>11</sup>

The only viable alternative to fracturing producing formations in reservoirs with low permeability would be to drill more wells in an area. Given the costs of drilling, the risks associated with creating multiple new vertical pathways for fluid migration, and the fact that it could take exceptionally large numbers of vertical wells located over a large area to equal the production of even a single hydraulically fractured horizontal well, this alternative is likely neither environmentally desirable nor economically viable. To overcome this, operators commonly drill multiple horizontal wells in different directions from a single wellpad site and these wells may extend laterally for several miles from the vertical aspect of the wellbore. From an environmental perspective, the API concludes that “horizontal drilling allows producers to drill multiple wells from a single well pad site, reducing surface disturbance and minimizing impacts on species and landscapes.”<sup>12</sup>

A great deal of attention has been focused on the process of hydraulic fracturing. Media outlets, environmental groups, citizen organizations, and the oil and gas industry have each expressed opinions about the safety and environmental effects of hydraulic fracturing. Addressing the issue is complicated by differences among these groups in their understanding of what the process entails, and whether development of oil and natural gas is viewed as good energy policy. To the oil and gas industry, “hydraulic fracturing” generally is understood to mean the actual process of

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<sup>9</sup> Where Our Natural Gas Come From, U.S. Energy Information Administration,

<https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php>

<sup>10</sup> George E. King, Apache Corp., [Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells](#), SPE Paper 152596 (Feb. 2012).

<sup>11</sup> Energy Information Administration (EIA), <https://www.eia.gov/todayinenergy/detail.php?id=34732>

<sup>12</sup> American Petroleum Institute (API), <https://www.api.org/~media/Files/Oil-and-Natural-Gas/Hydraulic-Fracturing/Environmental-Stewardship/Hydraulic-Fracturing-and-Horizontal-Drilling-Provide-Environmental-Benefits.pdf>

pumping fluids and proppant under pressure to fracture the rock. To others, hydraulic fracturing has become a more inclusive term that encompasses every activity associated with natural gas development from pad construction, drilling, production, pipeline transportation of gas, midstream processing of the product, and the disposal of waste products. Differences in the definition of hydraulic fracturing have led to misunderstandings and resulted in a greater level of concern than may have otherwise been associated with the discrete process of fracturing the formation. Regardless, it is important to note public discourse has continued to shift from an almost singular focus on hydraulic fracturing to other E&P issues such as well integrity failure, methane leaks, air pollution, plugging of abandoned wells and urban drilling.

### Fracturing Fluids

Fracturing fluid formulations may be based on water, acid, gel, or other media such as carbon dioxide or nitrogen foam. However, most fracturing work is conducted using water-based fluid. In addition to water, fracturing fluids typically contain an array of additives, each designed to serve a particular function. For example, in hydraulic fracturing of deep shale gas zones, the water is commonly mixed with a friction reducer to lessen the resistance of the fluid moving through the casing, biocides to prevent bacterial growth, scale inhibitors to prevent buildup of scale, and proppants, such as sand or ceramic beads, to hold the fractures open.<sup>13</sup> This type of fracturing process is often referred to as a “slickwater” fracture. The majority of additives to fracturing fluids, including sodium chloride, potassium chloride, and diluted acids, present low to very low risks to human health and the environment (Figure 4-4)<sup>14</sup>. However, some substances used in some hydraulic fracturing operations, such as ethylene glycol, components of petroleum distillates, and additives that contain or can be transformed into other, more harmful substances, have been linked to negative health effects at certain exposure levels.

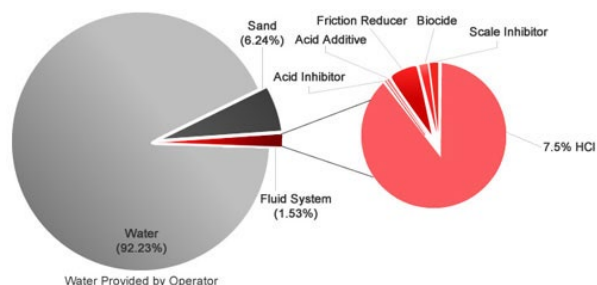


Figure 4-4 Typical ratio of fluids, by type, in a slickwater hydraulic fracturing fluid - Source, ALL Consulting

To address questions regarding the availability of information about the ingredients used in the hydraulic fracturing process, the GWPC and IOGCC worked together in early 2011 to create a

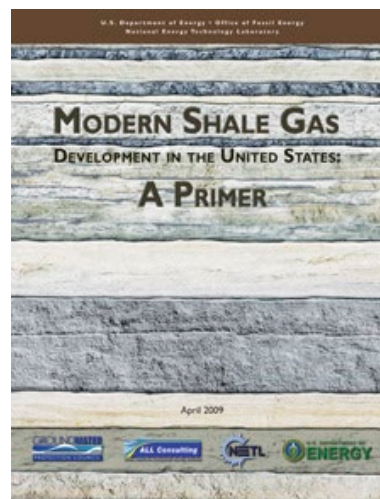
<sup>13</sup> P. Kaufman, G.S. Penny, J. Paktinat, [Critical Evaluation of Additives Used in Shale Slickwater Fractures, SPE 119900 \(Nov. 2008\)](#).

<sup>14</sup> Robert Porges & Mathew Hammer, National Ground Water Association, *The Compendium of Hydrogeology* (2001).

national hydraulic fracturing chemical registry. This system, (FracFocus®)<sup>15</sup> provides a platform for operators to submit information about the constituents used in the hydraulic fracturing process. It offers critical information to the public about the ingredients in hydraulic fracturing jobs and has become the de-facto standard for hydraulic fracturing chemical reporting in the U.S. with 23 states currently using it to meet their regulatory reporting needs.

Although a 2008 study conducted on behalf of the GWPC, with funding provided by the Department of Energy (DOE), indicated hydraulic fracturing fluids for a nine-staged, sequenced, “slickwater” fracture treatment of a horizontal well in the Fayetteville Shale were typically 98% to 99.5% water and proppants by volume, the increasing volumes being used to fracture wells still result in substantial overall volumes of additives. For example, in a hydraulic fracturing job that uses a base fluid volume of 10 million gallons of water a chemical that makes up only 0.01 percent of the total mixture would have a volume of 1,000 gallons.<sup>16</sup>

Fortunately, the dilution factor, presence of formation fluids, typical distances between fractured zones and groundwater zones, and the fact that chemicals such as acids are typically neutralized during the process, results in a very low probability that chemicals would contaminate groundwater resources. *NOTE: The 2008 primer is currently being updated with an expected release by mid-2023.*



**Figure 4-5 Shale Gas  
Primer- Source, GWPC**

One conceivable way to reduce public concerns about the additives used in hydraulic fracturing would be to exclusively use additives that are not associated with human health effects nor adversely impact the natural environment. For example, the oil and gas industry has responded to public and regulatory calls for the use of “greener” chemicals in hydraulic fracturing operations by developing alternatives to some ingredients, including diesel fuel. Research and development of alternative ingredients continues to advance and should result in an increased use of more environmentally friendly constituents over time. With respect to diesel fuel, which was cited as a principal constituent of concern by the U.S. Environmental Protection Agency (EPA) and the Oil and Gas Accountability Project (OGAP) because of its relatively high benzene content, a Memorandum of Agreement between the EPA and industry was reached in 2003 to discontinue diesel fuel use as a fracture fluid media in coalbed zones that qualify as Underground Sources of

<sup>15</sup> <http://www.fracfocus.org>

<sup>16</sup> Groundwater Protection Council & ALL Consulting, [Modern Shale Gas Development in the United States: A Primer](#) (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

Drinking Water (USDWs) (Appendix 10). In 2008, the GWPC conducted a follow-up survey, which found that in 25 agencies with potential coalbed methane production, diesel fuel was not being used to hydraulically fracture coalbeds that are USDWs. Between the development of the initial MOA in 2003 and the 2008 follow-up survey, Congress passed the Energy Policy Act in 2005. The act stated that hydraulic fracturing would not be considered a UIC activity unless diesel fuel was used. In February of 2014, EPA issued a final guidance document (Guidance #84) describing the criteria under which hydraulic fracturing would be considered a UIC activity requiring a permit<sup>17</sup>. In practice, diesel fuel use has dramatically decreased for well stimulations of all types, including hydraulic fracturing of shale formations. To evaluate the extent of diesel fuel use in hydraulic fracturing a recent review of FracFocus records of over 62,000 disclosures submitted between June 2016, and January 1, 2021, shows that in only fifteen stimulations (0.02 percent of fracture jobs) were any of the additives listed in EPA guidance #84 used. This contrasts with just over 105,000 records containing 54 such occurrences (0.05 percent of fracture jobs) found in a review of the FracFocus system between January 1, 2013, and May 1, 2016, and a nearly 0.04 percent use in fracture jobs between January 1, 2015, and May 31, 2016. Based on a comparison of these occurrence rates, the use of diesel fuel use in hydraulic fracturing has steadily decreased between 2014 and 2021.

### Exposure Pathways

The exposure effects of additives that can be contained in the treatment fluids can be mitigated by reducing exposure pathways. This is accomplished by ensuring the well being treated maintains mechanical integrity and by utilizing natural hydraulic barriers between the fractured zone and protected groundwater. Relevant to an analysis of exposure pathways in a GWPC/DOE study, discussed previously, which found that, depending on the design of a fracture job and the specific formation dynamics involved, anywhere from 30 percent to 70 percent of fracturing fluids are returned to the surface through the well casing.<sup>18</sup> The unrecovered treatment fluids are typically trapped in the fractured formation via various mechanisms such as pore storage and stranding behind healed fractures, thus isolating them from groundwater.<sup>19</sup> The risk of endangerment to groundwater is further reduced by other factors such as:

- Well construction practices including state regulatory standards and industry guidelines;
- Vertical distance between the fractured zone and groundwater;

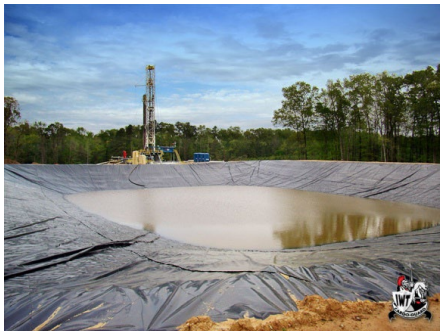
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<sup>17</sup> [Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuel, Underground Injection Control Program Guidance #84](#), Office of Water (4605M) EPA 816-R-14-001, February 2014

<sup>18</sup> Groundwater Protection Council & ALL Consulting, [Modern Shale Gas Development in the United States: A Primer](#) (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

<sup>19</sup> USEPA, [Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs](#), EPA 816-R-04-003 (June 2004).

- Presence of other zones between the fractured zone and the deepest groundwater zone that may readily accept fluid;
- Natural stress-induced limitations on vertical fracture propagation;
- Natural limits to fracture propagation posed by friction and fluid leakoff in the stimulated zone during the hydraulic fracturing operation;
- Presence of low permeability confining zones between the fractured zone and the deepest groundwater zone, which act as geologic barriers to fluid migration;
- Operational controls, such as the continuous monitoring of wellbore integrity during hydraulic fracturing operations; and
- Emerging sensor technologies which may allow for rapid detection of subsurface leaks.



**Figure 4-6 Lined pit designed to hold fluids during well drilling and completion - Source, IWT/ Cargo-Guard**

While the widespread use of effective, lower toxicity alternatives to traditional additives would decrease risk of environmental harm, the best way to protect groundwater is to isolate well treatment fluids from groundwater zones. Consequently, the primary mode of regulating hydraulic fracturing involves the application of well construction requirements designed to seal the wellbore and prevent the movement of fluids into groundwater.

Additionally, proper surface fluid handling methods can significantly decrease the likelihood of environmental harm from, or human exposure to, well treatment fluids. For example, once flowback fluids return to the surface, they are temporarily stored in tanks or lined pits (Figure 4-6) to isolate them from soils and shallow groundwater zones and are subsequently removed from the location for recycling or disposal. Exposure risk is, therefore, limited to spills and leaks from storage and transportation, which can be minimized by smart management practices and effective rules.

The ultimate fate of well treatment fluids returned to the surface is often determined by the availability of treatment and disposal technologies such as on-site or centralized treatment facilities and injection wells. Underground disposal via injection wells under the jurisdiction of a UIC program is the most common method of disposal for used fracture fluid. Prior to disposal, fluids are sometimes treated and re-used in subsequent fracturing operations, a practice that has seen increased attention and use in recent years. This growing trend toward recycling and reuse of fluids is discussed in “*Key Message 2: Emerging Issues*”. For facilities west of the 98<sup>th</sup> meridian, on-site treatment, and surface discharge, though rarely used, is also a disposal option,

where authorized by EPA or a state regulatory agency<sup>20</sup> (Figure 4-7). East of the 98<sup>th</sup> meridian, on-site treatment and direct surface discharge is typically not allowed.

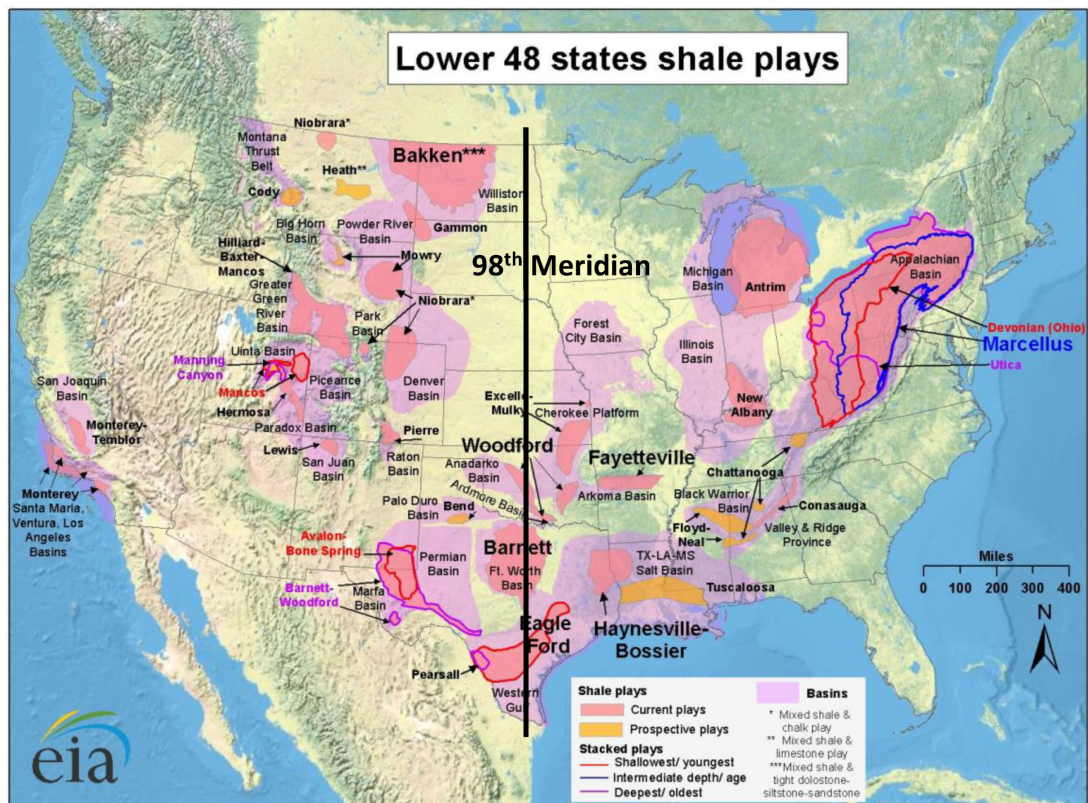


Figure 4-7 Shale plays in the lower 48 states – Source, Energy Information Administration

As noted in the 2014 edition of this report, indirect discharges such as through publicly owned treatment works (POTWs) or centralized wastewater treatment facilities (CWTs), was sometimes conducted, provided the fluid would not cause the facility to violate its permit or any state or national water laws or guidelines.<sup>21</sup> In June 2016, EPA published a new rule governing effluent limitations and standards for the onshore oil and gas industry. A clarification to these effluent limitations was published in the Federal Register in 2019.<sup>22</sup> This rule established pretreatment standards that prevented the discharge of pollutants in wastewater from onshore unconventional oil and gas (UOG) extraction facilities to POTWs because certain UOG extraction wastewater constituents are not typical of POTW influent wastewater and can be discharged, untreated, from the POTW to the receiving stream.

<sup>20</sup> Oil and Gas Extraction Point Source Category, 40 C.F.R. pt. 435 (subpart E—Agriculture and Wildlife Use Subcategory).

<sup>21</sup> See generally, James Hanlon, Director, Office of Wastewater Management, EPA, [Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions](#) (Mar. 2011).

<sup>22</sup> Federal Register Notice 84 FR 32094, July 2019, <https://www.federalregister.gov/documents/2019/07/05/2019-14361/decision-on-supplemental-information-on-the-effluent-limitations-guidelines-and-standards-for-the>

## Isolation Techniques

The risk of groundwater contamination resulting from the flowback of well treatment fluids returned to the surface through casing is low, since it would require simultaneous failures of multiple barriers of protection such as casing strings and cement sheaths.<sup>23</sup> A greater risk of contamination of groundwater comes from the potential for well treatment fluids to migrate upward within the casing/formation annulus during the treatment process and from surface spills; which may more readily affect shallow, unconfined groundwater zones. The most effective means of protecting groundwater from upward migration in the annulus is the proper cementation of well casing across vertically impermeable zones and groundwater zones. Proper cementation creates the hydraulic barriers that prevent fluid incursion into groundwater. The amount and placement of cement needed for this purpose will vary depending on several factors including the:

- Size of the casing/wellbore annulus;
- Quality of cement;
- Depth, thickness, and vertical permeability of formations between the fractured zone and groundwater; and
- Distance between the fractured zone and groundwater.

In general, the vertical separation between an oil and gas producing formation and the deepest groundwater zone in many parts of the country can be several thousand feet. However, there are cases where the distance between the producing zone and the groundwater zone is much smaller. In such cases, special considerations for constructing wells and conducting well stimulations may apply. For example, Texas has specific additional regulations governing wells that do not meet a “minimum vertical distance” between the zone to be fractured and protected groundwater zones.<sup>24</sup> Although a GWPC 2008 survey of state regulatory agencies found no determinations of contamination from the relatively shallow hydraulic fracturing of CBM reservoirs, the Texas rule indicates that concerns continue to exist. Regardless, the lack of demonstrated groundwater contamination where substantial intervals between the fractured zone and protected groundwater exist make it reasonable to conclude the risk of fracture fluid intrusion into groundwater from the hydraulic fracturing of deeper conventional and unconventional oil and gas zones should be considered very low.

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<sup>23</sup> Groundwater Protection Council & ALL Consulting, [Modern Shale Gas Development in the United States: A Primer](#) (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

<sup>24</sup> Texas Administrative Code, Title 16 Economic Regulation, Part 1 Railroad Commission of Texas, Chapter 3 Oil and Gas Division, April 2013

This conclusion is supported by the following factors:

- There is often significant vertical separation between the fractured zone and groundwater zones, especially in the majority of deep shale gas plays;<sup>25</sup>
- Well construction requirements in most agencies include provisions for cementation above producing zones and across groundwater zones;
- There are frequently layers of rock between the fractured zone and groundwater zones that are capable of accepting fluid under pressure, which would lower the available fluid that could reach a groundwater zone;
- There are also frequently layers of rock between the fractured zone and groundwater zone through which vertical flow is restricted, thus serving as a hydraulic barrier to fluid migration; and
- The use of advanced computer modeling in fracture design has increased the ability to predict the three-dimensional geometry of fracturing, which lowers the likelihood of a fracture job extending into an unintended zone.

### **Regulation of Formation Stimulation**

The authority to regulate the treatment of oil and gas wells is typically part of the general provisions of state oil and gas law; which contains a prohibition against pollution or contamination by oil and gas activities. Until recently, most well treatment practices were not regulated directly. Instead, oil and gas agencies regulated practices such as well construction and well testing, which are designed to prevent the migration of all fluids, including hydraulic fracturing fluids, from deeper to shallower zones. Provided these requirements are followed properly, and provided there are good geologic barriers between groundwater and the fracture zone that are not compromised by unplugged or poorly plugged abandoned wells, the process of formation stimulation itself should not affect groundwater. Some agencies, such as Oklahoma, have consolidated existing regulations with a relationship to well treatment into a single section of their regulatory language. Other agencies have introduced new direct regulation on acceptable chemical use, pre-stimulation reporting requirements, pressure limitations and monitoring standards, cessation of operations for MI failure, and surface equipment integrity testing.

### **Limitations and Requirements**

As of January 2021, more agencies had placed specific limitations on the well treatment process. The following is a partial list of well treatment requirements by rule and examples of some states that implement them:

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<sup>25</sup> Groundwater Protection Council & ALL Consulting, [Modern Shale Gas Development in the United States: A Primer](#), (Apr. 2009) (prepared for DOE and the National Energy Technology Laboratory).

- Prohibitions against, or prior approval for, the use of some chemicals (Alabama, Arkansas, Colorado, Illinois, Oklahoma, Utah, and Wyoming);
- Minimum depths or distance from protected water (Alabama- Coalbed methane only, Texas);
- Geologic evaluations of the interval between the zone to be fractured and groundwater zones ( Alabama, Alaska, Arkansas, California, Illinois, Indiana, Mississippi, and Texas);
- Additional requirements on wells that do not meet a minimum intervening interval between the fractured zone and protected groundwater (Texas);
- A review of the area around the wellbore for natural and artificial conduits (Alabama, Alaska, Arkansas, California, Illinois, Indiana- Coalbed methane only, Mississippi, Ohio, and West Virginia);
- Adjacent water well testing and monitoring ( Alaska, Arkansas, California, Colorado, Illinois, Indiana, Kentucky, Michigan, Ohio, Virginia, West Virginia, and Wyoming);
- Requirements that fracture fluids be confined to the zone to be fractured (Alabama, Alaska, Arkansas, California, Colorado, Illinois, Indiana, and Mississippi);
- Annular pressure monitoring during fracturing operations with job termination criteria (Alaska, Arkansas, California, Illinois, Indiana, Michigan, Ohio, and Texas); and
- Pressure limitations (Alabama, Alaska, Arkansas, California, Illinois, Mississippi, Montana, Nebraska, and North Dakota).

*NOTE: These examples do not comprise the full list of requirements or states.*

### **Disclosure and Reporting**

In the 2014 edition of this report, 21 of the agencies reviewed required some degree of reporting of chemicals used in wells. By the 2017 edition, the number of agencies requiring reporting had risen to 24. By 2021 this number had again risen, and is now 25. (An increase of 16 percent since 2014) Between 2009 and 2014 many agencies expanded their reporting requirements to include a list of the chemicals used in hydraulic fracturing jobs, the name of the supplier, the amount, or percent by mass of the chemicals used, the trade name of the products used, and the Chemical Abstract Number (CAS)<sup>26</sup> of each chemical used. In 2011, the GWPC and the IOGCC partnered to create a hydraulic fracturing chemical disclosure registry. This registry, known as FracFocus, was initially designed to be a website where oil and gas operators could report their hydraulic fracturing chemicals on a voluntary basis. The purpose of the site was to provide information about the process of hydraulic fracturing to the public and to allow nearby landowners to see records that showed the chemicals being used on or near their property. Prior to 2021 the FracFocus website allowed the public to search for hydraulic fracturing disclosure records using

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<sup>26</sup> The Chemical Abstract Service is maintained by the American Chemistry Council. *See generally*, Chemical Abstract Service , <https://www.cas.org>.

only such criteria as the state, county, operator, well name, date of job or submission date, and chemical names. In 2022 the public portion of FracFocus should be updated with a new user interface which will allow individuals to also use counties and zip codes to search for nearby hydraulic fracturing disclosure records, and to display their locations on a map. FracFocus presents individual disclosure records in an Adobe pdf ® format which can be printed or downloaded. In May 2015 the FracFocus system also began providing downloads of machine readable datasets in SQL and CSV formats. These downloads are currently updated daily and posted to the FracFocus website along with instructions for obtaining them. As of July 25, 2022, more than 2,100 companies had signed up to submit records to the system and more than 1,700 companies have submitted almost 196,000 disclosures.

As the popularity and effectiveness of the FracFocus website grew, several agencies decided to adopt the site as their means of regulatory reporting. As of the 2017 report 20 of the 27 agencies reviewed had designated the FracFocus website as an official location for filing regulatory chemical disclosures. By 2021 this number had risen to 23 of the 27 agencies reviewed. 2014 (See Appendix 12- current as of January 2021). Three agencies that were not part of this review (North Carolina, Nevada, and Idaho) also require or allow the use of FracFocus.

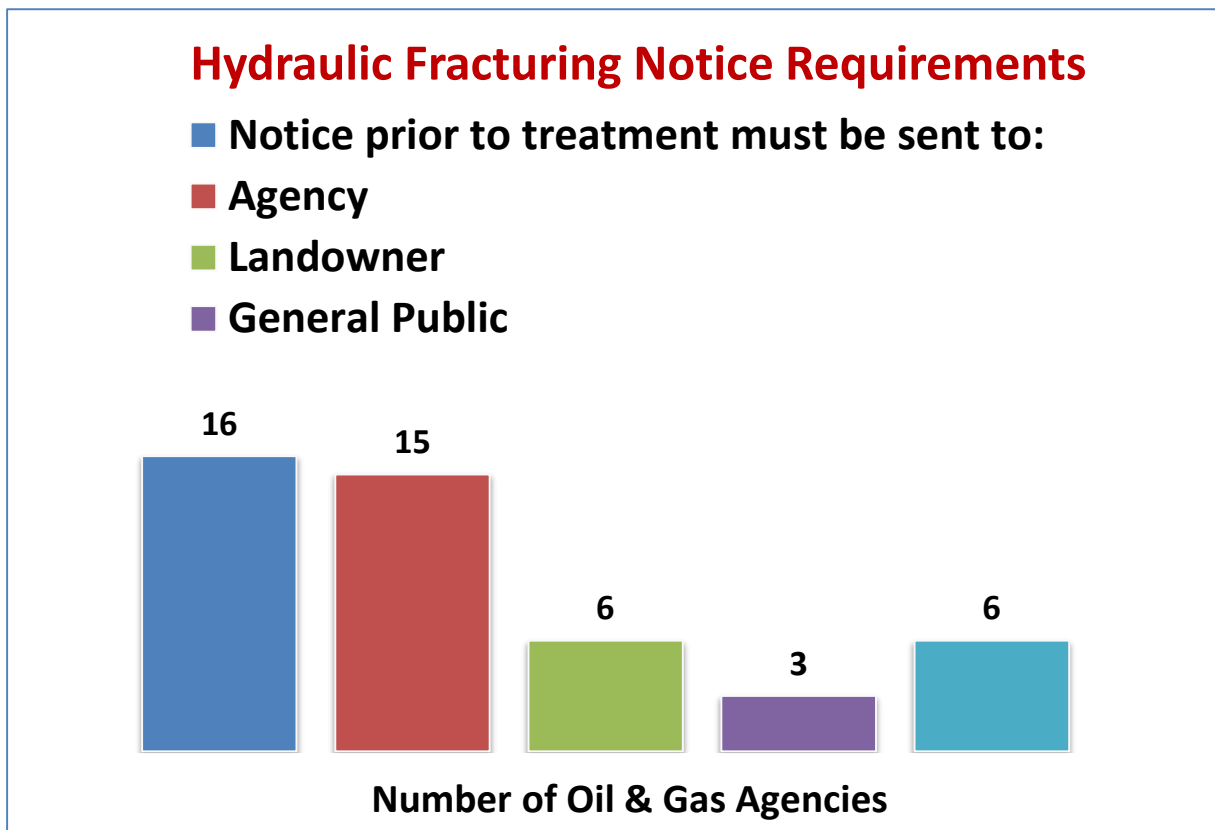


Figure 4-8

### January 2021 Findings

Regulatory requirements on hydraulic fracturing have been increasing as a result of both public concern and evaluations of need by oil and gas agencies. A review of regulations relative to hydraulic fracturing shows that 23 of the reviewed agencies have specific regulations governing the practice. Further, 16 agencies require a prior notice to the agency before fracturing can be initiated. Additionally, 12 agencies require adjacent water well testing as a condition of conducting hydraulic fracturing. Figure 4-9 details some hydraulic fracturing requirements and the number of agencies that implement them.

In addition to the permitting requirements for hydraulic fracturing, there are 16 agencies that require a prior notice to the agency or to other persons when hydraulic fracturing is to be conducted. For example, while 15 agencies required a prior notice to the agency, there were also six that required notification being given to landowners and another six that required prior notice to offset operators. Figure 4-9 shows the prior notice requirements for hydraulic fracturing.

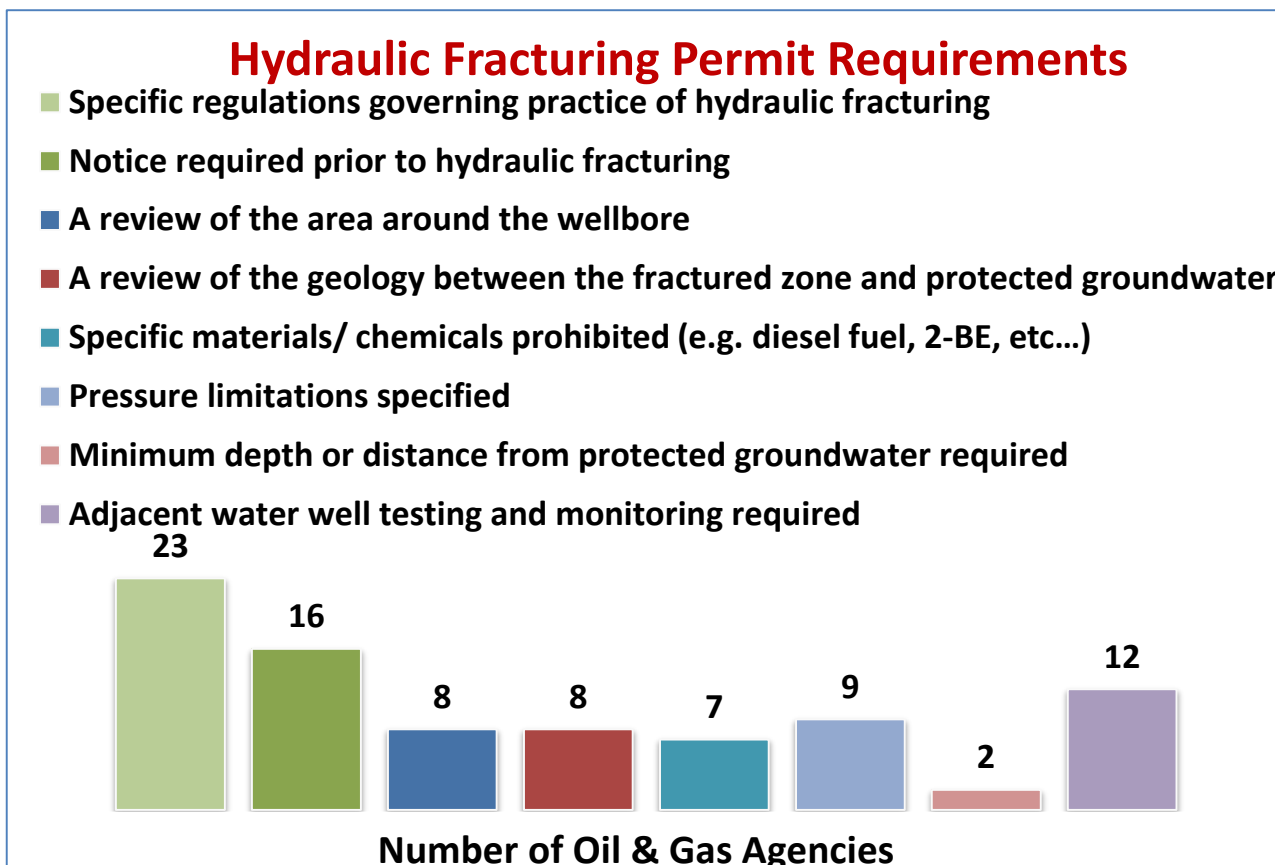


Figure 4-9

With respect to the operational requirements imposed by agencies on the process of hydraulic fracturing several are notable. Eight agencies specifically require the hydraulic fracturing fluid to be confined to the target reservoir. In 11 states the agency requires operators to monitor and record the fracturing job. If mechanical integrity failure is indicated during the job, ten agencies require immediate cessation of fracturing (a 30 percent increase since 2017 ). Figure 4-10 shows some of the specific operational requirements and the number of agencies that apply them.

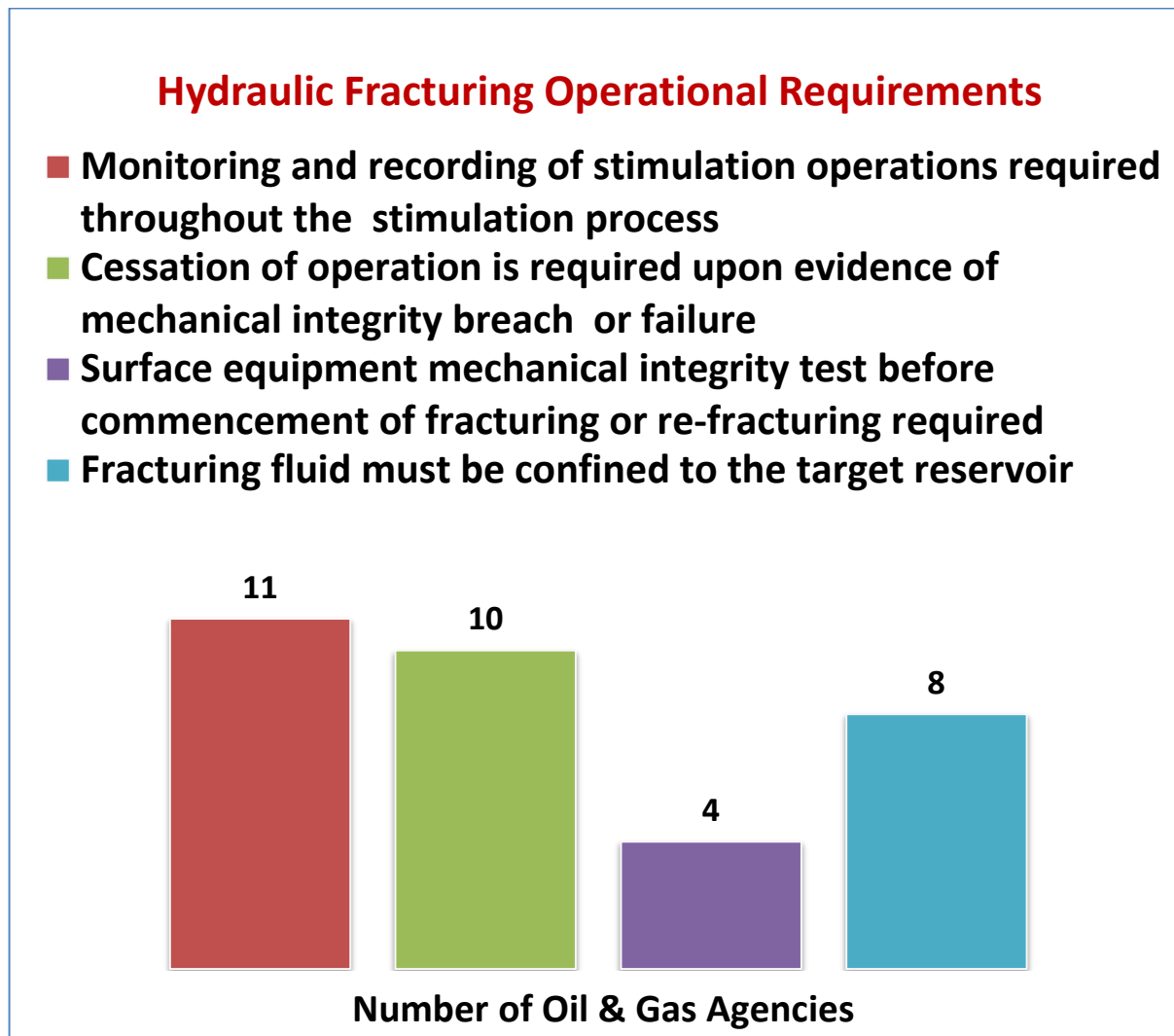


Figure 4-10

Although all of the states reviewed required some information such as types and amounts of materials used to be reported to the agency following hydraulic fracturing operations, 26 agencies specifically require post hydraulic fracturing chemical disclosure reporting.

Twenty-six agencies require submission of water volumes used and the specific additives and the volumes of each, or their percentages against the total volume used in the job (an almost 12 percent increase since 2017). Figure 4-11 details some of the post hydraulic fracturing reporting requirements.

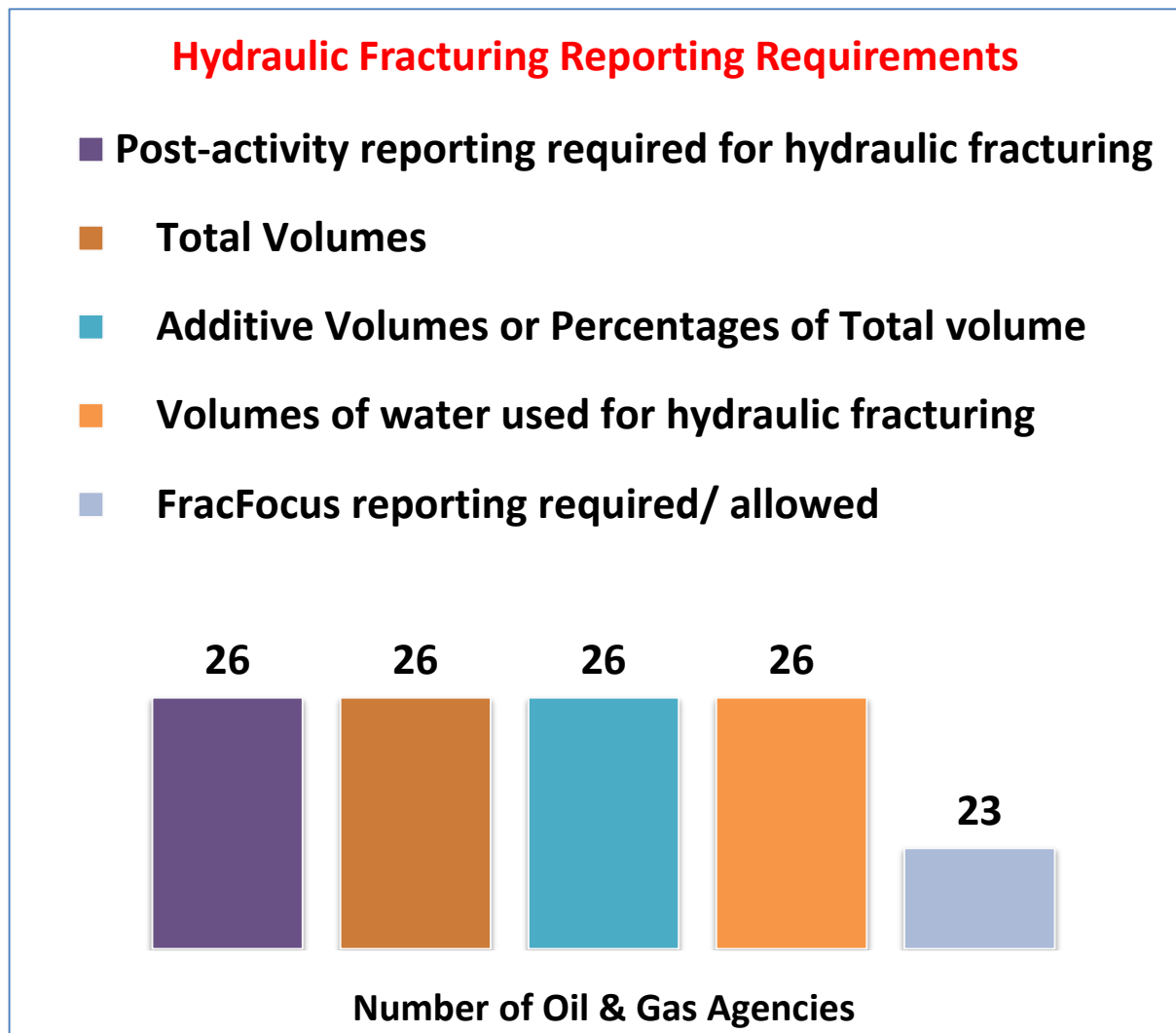


Figure 4-11

Appendix 3 is an example of a typical chemical disclosure report from the FracFocus system shown in the “Systems Approach” format which decouples the trade name of the product from its ingredients.

## Well Integrity

From the perspective of water protection, well integrity means the structurally sound construction of a well including competent pressure seals and operational controls that effectively prevent uncontrolled fluid releases or migration of annular fluids into protected groundwater throughout the life cycle of a well. In August 2016, the GWPC developed a list of well integrity regulatory elements in six categories which agencies may want to consider when addressing well integrity. These elements were updated in 2021.<sup>27</sup>

In the 2013 Society of Petroleum Engineers (SPE) Paper # 166142, *“Environmental Risk Arising from Well Construction Failure: Difference Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations and Well Age,”* petroleum engineers George King and Daniel King describe the difference between barrier failure and well integrity failure.<sup>28</sup> In a barrier failure case, a single barrier, or even multiple barriers in a well (casing and/or cement) may fail. However, provided additional layers of protection remain intact and flow pathways between the wellbore and the formation do not occur, a well can still be considered to have integrity. The key to maintaining integrity is establishing redundant barriers. As the authors put it, “In most well configurations, uncemented sections of inner pipe strings are designed to collapse under any over pressuring external load in the annulus before the pipe that forms the outer wall of the annulus can burst. This type of reactive barrier protects the integrity of the outer string with a sacrificial collapse of the inner string.” In essence, the production string is designed to collapse under over pressure before the surface casing can be compromised.

Proper placement and cementing of surface casing is one of the most critical groundwater protection measures during well construction. Once in place, it is also critical to protect the surface casing shoe from annular fluids that are sufficiently pressurized to allow fluid migration into protected groundwater. Additional layers of casing and cement are emplaced to isolate producing zones and other flow zones that are encountered while drilling below the surface casing. The cementing of surface casing protects groundwater during the drilling process and isolates it from deeper saline and petroleum containing zones, which can also be over-pressured or contain corrosive fluids and present a threat to protected groundwater.

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<sup>27</sup> Ground Water Protection Council, Well Integrity Regulatory Elements for Consideration, [https://www.gwpc.org/wp-content/uploads/2021/03/Well\\_Integrity\\_Elements\\_Revised\\_1\\_19\\_2021\\_002.pdf](https://www.gwpc.org/wp-content/uploads/2021/03/Well_Integrity_Elements_Revised_1_19_2021_002.pdf)

<sup>28</sup> George E. King and Daniel E. King, *Environmental Risk Arising from Well Construction Failure: Difference Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations and Well Age*, SPE 166142 (2013).

## Well Materials and Construction Requirements

Casing is typically steel pipe used to line the inside of the drilled hole (wellbore). The most widely used standard for oil and gas casing was established by the API in Spec. 5CT. It specifies the length, thickness, tensile strength, and composition of casing and is still the most commonly used standard for the selection of oil and gas casing. Each full length of casing is referred to as a casing string. Wells are typically constructed of multiple casing strings including a surface string and production string. These strings are set in the well and cemented in place under specific state requirements. API SPEC 10A, 25th Edition, March 2019 established standards for cement types, listing a variety of oil and gas cements and cement additives. Although Class A (Portland) cement is the most common cement used in the oil and gas industry, the type of cement can be tailored to the individual well provided the state allows this degree of flexibility. For example, some wells penetrate formations that are difficult to cement because of their porous nature or due to a substantial water flow within the formation. In such cases, additives like cellophane flake and calcium chloride are sometimes added to the cement to seal off such zones, quicken the cement hardening process, and prevent washout of the cement.

## The Casing and Cementing Process

In general, the casing of oil and gas wells, whether vertical or horizontal, is accomplished in multiple phases from the largest diameter casing to the smallest. The first phase often involves the setting of conductor casing. The purpose of this casing is to prevent the sides of the hole from caving into the wellbore where it is drilled through unconsolidated materials such as soil layers. After the conductor casing is set, drilling continues inside the conductor string to below the lowest protected groundwater zone depending on regulatory requirements. Surface casing is then run from the surface to just above the bottom of the hole. As of 2021, 26 of the 27 states reviewed specifically require the setting of surface casing below all protected groundwater zones. In one state this is not a specific requirement. Instead, this state uses a casing setting depth table, which is designed to accomplish a similar result. After surface casing is run, cement is pumped down the inside of the casing, forcing it up from the bottom of the casing into the space between the outside of the casing and the wellbore, called the annulus. Once a sufficient volume of cement to fill the annulus is pumped into the casing, it is usually followed by pumping a volume of fresh water into the casing until the cement begins to return to the surface in the annular space. The cementing of casing from bottom to top using this method is called circulation. The circulation of cement behind surface casing ensures that the entire annular space fills with cement from below the deepest groundwater zone to the surface. All 27 of the agencies reviewed in 2021 required the circulation of cement around the surface casing.

Once the surface casing is set and the cement has time to cure, the wellbore is drilled down to the next zone where the intermediate or production casing will be set. In some agencies, an

intermediate casing string is often run after the surface casing but before the production casing. This is usually required only for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones. For example, in New York, intermediate casing may be required for fluid or well control reasons or on a case-specific basis, while in Wyoming, intermediate casing can be required where needed for pressure control or to protect natural resources. In Ohio, where surface casing is typically set between 300 and 700 feet due to the shallow nature of protected groundwater, construction rules for new wells mandate installation of intermediate casing string in all horizontal wells as an additional pressure control barrier. Since hydro-geologic and reservoir characteristics differ regionally, intermediate casing requirements vary from state to state.

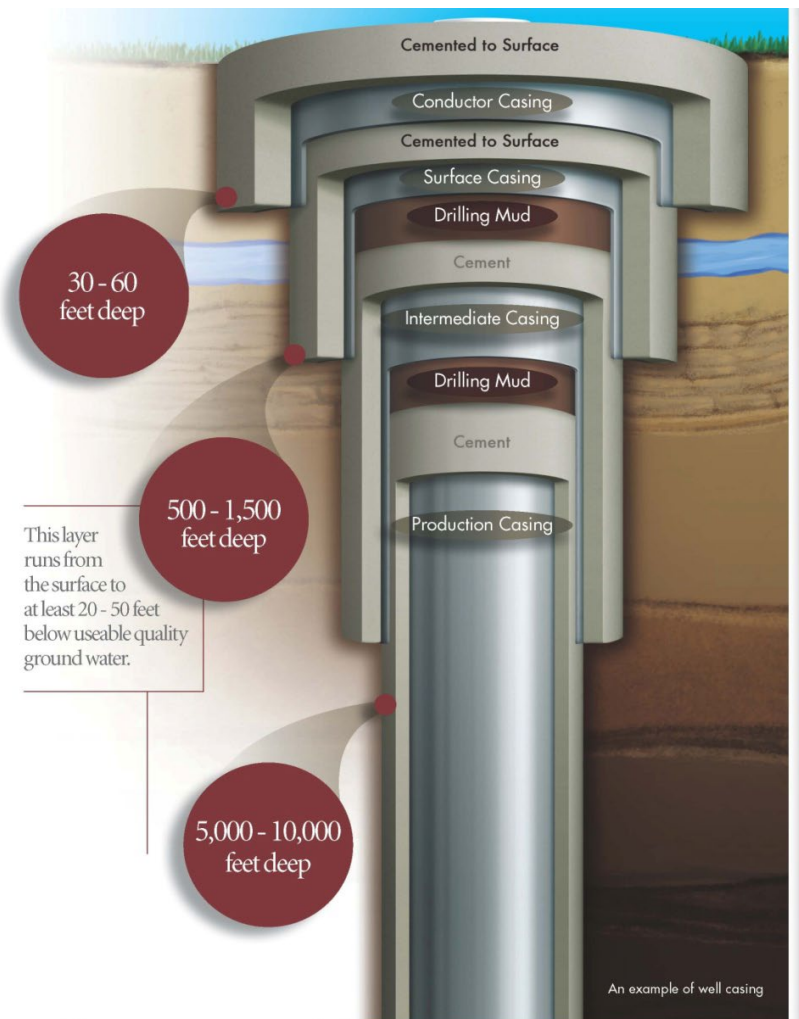


Diagram courtesy of the Texas Oil & Gas Association

Figure 4-12 – Source Texas Oil & Gas Association

After the surface and/or intermediate casing strings are set, the well is drilled to the target formation. Upon reaching this zone, production casing is typically set at either the top of, or into, the producing formation depending on whether the well will be completed “open-hole” or through perforated casing. The production casing is typically set into place with cement using the same method as for surface and intermediate casing. Where appropriate, such as when the drill hole has deviated from vertical, casing centralizers are used to assure the casing is centered in the hole prior to cementing so that cement will completely surround the casing. An exaggerated (Not to Scale) cross-sectional diagram of a well equipped with casing and cement is shown in Figure 4-12.

Although some agencies require complete circulation of cement from the bottom to the top of the production casing, most agencies require only an amount of cement calculated to raise the cement top behind the casing to a certain level above the producing formation or other flow zones that may overlie the target reservoir. For example, in Arkansas, production casing must be cemented to 250 feet above all producing intervals.

There are a number of reasons why cement circulation from bottom to top on production casing is not typically required, including the fact that, in very deep wells, the circulation of cement is more difficult to accomplish. Cementing may be handled in multiple stages, but this can result in a poor cement job or damage to the casing if not done properly. Also, the circulation of cement on production casing prevents the ultimate recovery and potential reuse of the casing when the well is plugged and prevents the replacement of casing during the life of the well. While there are differing views regarding bottom to top cementing of the production casing annulus, the presence of the un-cemented annulus does provide a means to evaluate the ongoing mechanical integrity of a well through annular pressure monitoring.

Some agencies also require the use of well tubing in addition to casing strings. Tubing, like casing, typically consists of steel pipe that follows the same standards as casing established by the API. The principal difference between casing and tubing is that tubing is not typically cemented into the well.

### **The Relationship of Well Integrity to Groundwater Protection**

Casing strings are an important aspect of well integrity with respect to groundwater protection, providing for the isolation of protected groundwater zones. Casing is also used to isolate producing zones, pump fluids down the wellbore into the target reservoir during hydraulic fracturing stimulations, transmit flowback fluids from well treatment back to surface containment facilities, and to convey crude oil, natural gas, and produced water to surface during the productive life of a well. In this regard, surface casing is the first line of defense and production casing provides a second layer of protection for groundwater. As important as casing is, however, it is the cementation of the casing that adds the most value to the process of groundwater protection. Proper sealing of annular spaces with cement creates a hydraulic barrier to both vertical and horizontal fluid migration. Consequently, the quality of the initial cement job, including cement quality and placement, is perhaps the most critical factor in the prevention of fluid movement from deeper zones into groundwater resources. Cement quality can be affected by a number of factors, including:

- **Quality of the mix water:** The use of excellent quality water for cement mixing is very important because contaminants in the water (such as tannins from decaying vegetation) can affect the ability of the cement to harden;
- **Ratio of cement to water:** Proper setting of the cement depends on the use of the correct cement to water ratio in the mixture. Too little water and the cement will not pump properly; too much water and the cement will not harden properly. Water in excess of what is required to fully hydrate the cement is called free water. In technical literature, and in some cases in rule, typically a maximum free water amount is specified for each cement mixture;
- **Additives used in the cement:** There are dozens of oilfield cement types including standard Class A (neat) cement, Class H (high temperature) cement, Pozmix® (a mixture of fly ash and cement), and many others. Each is used under particular circumstances such as in deep wells, over-pressured wells, etc. There are also a wide variety of additives that can be blended with the various cement types to modify cement properties in response to site-specific conditions. For example, additives can prevent lost circulation, reduce, or increase slurry density, and accelerate or retard the development of compressive strength. Engineers design cement-additive blends for each application to ensure that the cement not only sets properly but has the correct characteristics and integrity to prevent fluid flow;
- **Curing time allowed:** Prior to drilling out the cement used to set the casing, it is important to allow it to cure properly. This is usually accomplished by establishing a minimum curing time for the cement. Failure to allow the cement to cure properly can cause cement failure or loss and lead to channeling of the cement behind the casing, which could result in fluid flow; and
- **Placement procedures:** Most primary cementing operations employ a two-plug cement placement method. After drilling through an interval to a desired depth, a crew removes the drill pipe, leaving the borehole filled with drilling fluid. A casing string is then lowered to the bottom of the borehole. As the casing string is lowered, the interior may fill with drilling fluid. This fluid must remain isolated from the cement because the fluids are typically incompatible and when in contact with one another can form a gel that may be difficult to remove from the pipe. Chemical washes and spacer fluids are usually pumped after the drilling fluid and before the cement slurry. Wiper plugs are also placed at the interface between the drilling fluid and the cement and between the cement and the displacement fluid to keep the fluids separated. When the bottom wiper plug hits bottom it allows the cement to pass through into the annulus and fill the backside of the casing. When the top wiper plug hits bottom, it remains and closes the hydraulic connection between the inside of the casing and the annulus. Proper cement placement means the primary cement job forms a hydraulic seal in the annulus and prevents the migration of fluid between zones.

## Well Testing and Integrity Evaluation

In some agencies, it is common for state personnel to witness the running and cementing of casing strings; in others, the submission of a completion report detailing the amounts and types of casing and cement used in the completion of the well is considered sufficient evidence of proper well construction. Some agencies, including Michigan, Ohio and others, may require an additional verification method using geophysical logs such as Cement Bond Logs (CBL) and in some cases Variable Density Logs (VDL). By measuring the travel time of sound waves through the casing and cement to the formation, the CBL may indicate the quality of bonding between the casing and the cement. The VDL performs a similar function to measure the bond between the cement and the borehole. By measuring the quality of the cement to casing and cement to formation bond, the sealing quality of the cement in the annulus may be determined. However, the API warns that “Caution should be exercised when using cement evaluation logs as the primary means of establishing the hydraulic competency of a cement barrier. The interpretations of cement evaluation logs are opinions based on inferences from down hole measurements. As such, the interpretation of cement evaluation logs can be highly subjective.”<sup>29</sup>

There is no “silver bullet” method to effectively evaluate whether a cement job has met performance objectives. In addition to measurements recorded during each job and measurements of cement bonding, additional integrity tests can be made to determine whether there are migration pathways through the annular cement. Several cased hole geophysical logs can be used for this evaluation including:

- **Temperature logs:** Temperature logs measure a variation in temperature against a reference gradient. Variations from the gradient signal the movement of fluids into a borehole or flowing behind casing;
- **Noise logs:** A noise log is an acoustic log that measures sound behind casing, enabling a determination of whether fluid is flowing behind the pipe;
- **Radioactive Tracer Survey (RTS):** This tool uses a set of injectors and detectors to determine whether an injected tracer has moved from an injection point. If a radioactive tracer injected at one depth is detected at a shallower depth, it indicates an upward fluid flow behind the casing and
- **Oxygen activation log (O2):** O2 logs use the decay factor of oxygen activated by high-energy neutrons to produce an isotope of nitrogen which decays back to oxygen with a half-life of 7.1 seconds and produces a detectible gamma ray. Count rates are measured to determine the velocity, flow rate, and distance of water from the tool.<sup>30</sup>

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<sup>29</sup> American Petroleum Institute, *Isolating Potential Flow Zones During Well Construction*, HF 65-2, (Dec. 2010).

<sup>30</sup> *Oilfield Glossary*, SCHLUMBERGER, <http://www.glossary.oilfield.slb.com/>.

Certain geophysical logs are designed only to evaluate the cement behind the casing. Other means of demonstrating different parts of well integrity include formation integrity tests, casing pressure tests, and casing/tubing annular pressure tests. No single geophysical tool will work under all circumstances, and proper tool selection, calibration, and skilled interpretation are essential.

### January 2021 Findings

Several elements related to well drilling, construction, and integrity are required to provide protection for groundwater resources. For example, while it is typical for operators to notify inspectors regarding the schedule for drilling a well, 11 states require a prior notification to the agency before well construction is undertaken. This notice increases the chances the agency will be able to have someone on site to witness the running and cementing of casing; which is a critical element in the protection of groundwater. The quality of the materials used in the construction of the well is also of great importance. In this regard seven agencies have requirements on the use of reconditioned casing and ten specify the casing must be rated for the conditions expected to be encountered during operation of the well. Further, 13 agencies have specific cement standards such as cement type limitations, requirements for use of API approved cements, limitations on free water content in cements and others. All of these numbers demonstrate increases from the 2017 report.

Perhaps the most critical element related to groundwater protection involves the running and cementing of surface casing. Because surface casing provides the first line of defense for groundwater zones and is typically run below the deepest protected groundwater aquifer it is very important to make sure it is run and set properly. In this regard 26 agencies in the study require that surface casing must be set below the base of protected groundwater and cemented from the bottom to surface. Also, 11 states prohibit the use of oil based muds, and ten prohibit non-freshwater drilling fluids for the surface casing portion of the well. Thirteen agencies require the surface casing be pressure tested prior to drilling out the cement. Further, eight agencies also require operators to set centralizers on the surface casing at appropriate intervals to ensure centering of the casing in the hole, which facilitates circulation of the cement completely around the casing string ( a 37.5 percent increase since 2017). With respect to cement integrity, 22 agencies require the operator to wait a specified amount of time after cementing surface casing before proceeding with additional drilling. This “wait on cement” time insures that the cement has had time to cure to provide the best hydraulic seal behind the casing prior to “drill-out.” In addition to specifying requirements for well construction and cementation, many agencies can require well integrity demonstrations. For example, 22 agencies can compel an operator to provide cement evaluation logs such as a CBL/VDL, temperature, noise, or other logs when it is deemed necessary to verify cement integrity and cement bond quality behind the casing. Figure

4-13 shows some of the surface casing, drilling, and construction requirements agencies use to insure well integrity and groundwater protection.

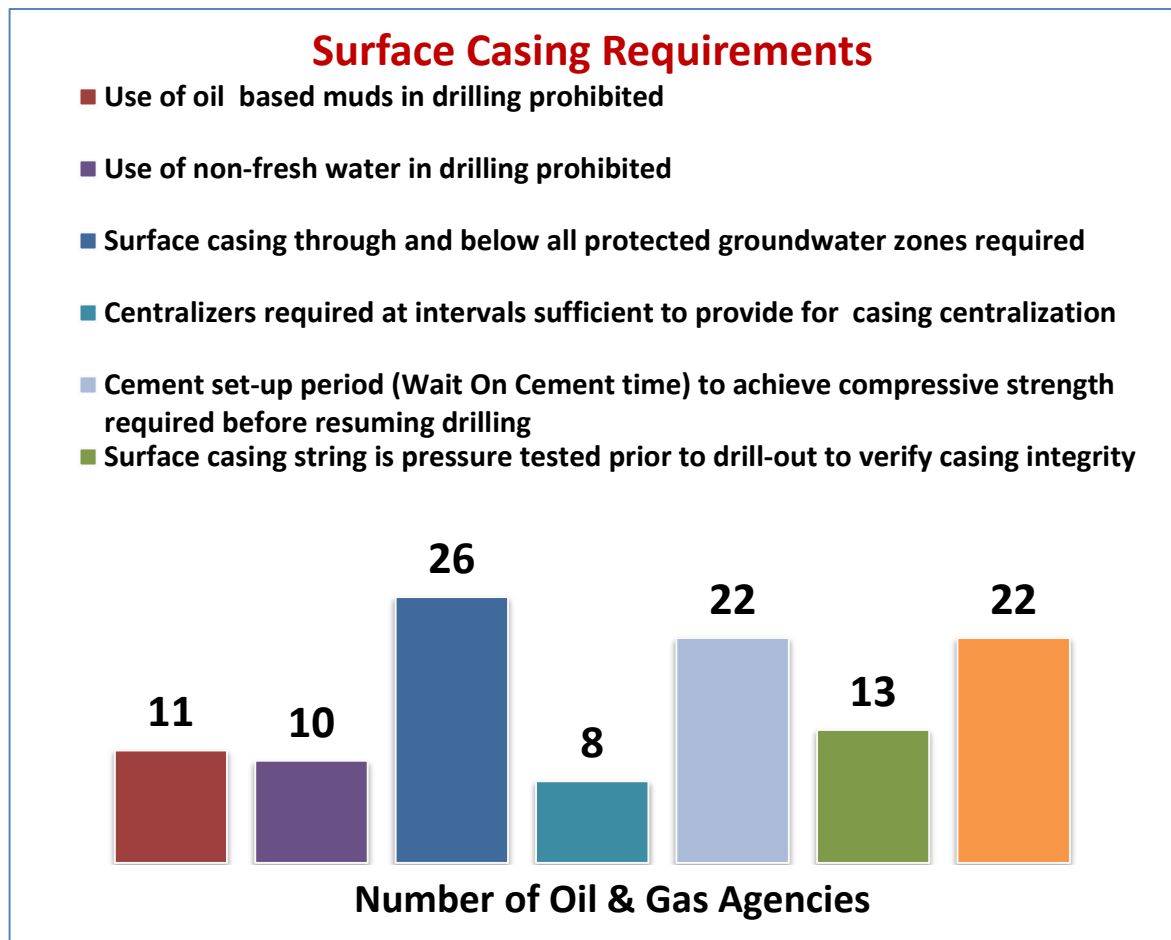


Figure 4-13

In addition to surface casing, many states require the setting of additional casing strings such as intermediate or long string casing to protect groundwater, oil, gas, and coal bearing zones, or to seal off high pressure or corrosive zones. For example, nine agencies require the use of intermediate casing in certain circumstances, while 18 require long string/ production casing.

### Temporary Abandonment

Temporary abandonment (TA) is a state regulatory process that allows oil and gas operators an opportunity to keep wells intact rather than plug them during periods when there may be no production from the well (such as during periods of economic stress). This practice is common in many agencies. The primary purposes of allowing temporary abandonment are to prevent plugging wells that may have future economic value and to avoid drilling replacement wells.