STATE OIL & GAS

regulations designed to protect

WATER RESOURCES

2014 EDITION

SOGRE
State Oil and Gas Regulatory Exchange

GROUNDWATER PROTECTION COUNCIL

PREFACE

This report has been developed by the Ground Water Protection Council (GWPC) as an update to the 2009 publication, "State Oil and Natural Gas Regulations Designed to Protect Water Resources."[1] The purpose of the earlier study, based on a review of 27 states, 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 state approaches related to those areas. This update describes the continuous regulatory improvement that states have made during the past four years as they enhance state regulatory programs. This report has been endorsed by the State Oil and Gas Regulatory Exchange (SOGRE).

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 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 and Interstate Oil and Gas Compact Commission (IOGCC) believe that regulation of oil and gas field activities is managed best 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.

For this updated report, the GWPC reviewed the same 27 states from the 2009 report, modifying and adding selected areas and related elements to facilitate an expanded review. Differences in review findings between 2009 and 2013 are highlighted for each area or element, and proposed rules are profiled where applicable. This update also discusses results from an additional survey that was submitted to the states related to specific aspects of their oil and gas regulatory programs including their staffing, permitting, funding, and inspection and witnessing of field processes. Both the 2009 and 2013 studies include a variety of considerations for state policymakers and researchers.

We would like to thank the following surveyed state oil and gas regulatory agencies for their participation:
Alabama State Oil and Gas Board
Alaska Oil & Gas Conservation Commission

1 *Groundwater Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources* (Apr. 2009), available at http://www.gwpc.org/sites/default/files/state_oil_and_gas_regulations_designed_to_protect_water_resources_0.pdf .

Arkansas Oil and Gas Commission
California Department of Conservation, Division of Oil, Gas and Geothermal Resources
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 Environmental Quality, Office of Oil, Gas and Minerals
Mississippi State Oil and Gas Board
Montana Department of Natural Resource Conservation, Board of Oil and Gas
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 Management
Oklahoma Corporation Commission, Oil and Gas Conservation Division
Pennsylvania Department of Environmental Protection, Office of Oil and Gas Management
South Dakota Department of Environment 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 Department of Mines, Minerals and Energy, Division of Gas & Oil
West Virginia Department of Environmental Protection, Office of Oil and Gas
Wyoming Oil and Gas Conservation Commission

We would also like to thank the U.S. Department of Energy, Environmental Defense Fund and American Petroleum Institute for their assistance with this report. We reviewed recommended practices, standards and documents by these three groups as well as the GWPC and the IOGCC, and the reader will find a number of them reflected in the report's "Considerations".

The views expressed in this report, as well as any suggested "Considerations", are those of the authors and do not necessarily reflect those of any particular state. State regulatory programs are significantly more detailed and comprehensive than could possibly be represented in this summary report. Subsequently, we always recommend the reader contact an individual state oil and gas agency for further clarifications and/ or additional information. We hope you will find this report informative and useful.

Michel Paque
Executive Director

Inside front cover
[This page is intentionally blank]

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In step with dramatic industry growth over the past five years, states have substantially improved groundwater protection laws and regulations governing oil and natural gas production. 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.

Typical rotary drilling operation Source, Southwestern Energy

This report, prepared by the Ground Water Protection Council (GWPC), is designed to equip regulators and policymakers with pertinent data and observations to consider when evaluating and revising rules in their states. It includes an overview of 2013 groundwater protection rules in 27 oil- and gas-producing states, a discussion of how rules have evolved since an initial review in 2009, and considerations for regulators and policymakers derived from leading practices adopted or proposed in various states.

The report also introduces several emerging issues that merit more detailed consideration in future state regulatory evaluations. With regard to well integrity, for example, these emerging issues include approaches to analyzing stratigraphic containment and potential conduits of fluids from the stimulated zone to protected water, including using the area of review (AOR) concept, similar to the one used in the underground injection control (UIC) program, and mitigation where appropriate; kick reporting and mandatory suspension of stimulation operations when problems are encountered; and taking a lifecycle approach to well integrity through such measures as annular pressure and bradenhead monitoring. Other significant issues related to groundwater protection include: sampling and analysis of water resources potentially impacted by the oil and gas well drilling, completion, and operation activities; treatment operations and waste stream management related to the use of brackish and/or saline groundwater; the reuse of produced water; and the proper disposal, handling, and exposure limits related to naturally occurring radioactive material (NORM) brought to the surface in produced water and drill cuttings.

This report highlights several practices adopted by oil- and gas-producing states 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 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.

Since 2009, states have made considerable progress in the areas tracked by this report. As oil and gas E&P has increased dramatically around the country and especially in areas where unconventional resources are present, the public has expressed increasing concern about the safety and environmental impact of oil and gas development. In response, state oil and gas agencies have revised their programs to improve the quality of operations. Especially notable are updates to requirements for chemical disclosure of hydraulic fracturing fluids, enhancements to mechanical integrity testing, improved pit siting and lining requirements, and advances in data management. However, several needs remain including those for additional research into the risks to water from the practice of hydraulic fracturing, and the presence of NORM. When states update their rules, consideration should be given to focusing on areas that will increase protection for water resources including well integrity, surface fluid management, and cleanup standards for spills. Interagency and interstate coordination of activity will also become more critical, as will the need for data integration between disparate data systems

Overall, state oil and natural gas regulatory agencies have been diligent in addressing the technological, legal and practical changes that have occurred in oil and gas E&P over the past four years. By employing highly trained, experienced staff and implementing rules designed to protect water resources, agencies have maintained a standard of regulatory management that assures water availability and sustainability.

State Regulatory Trends and Considerations

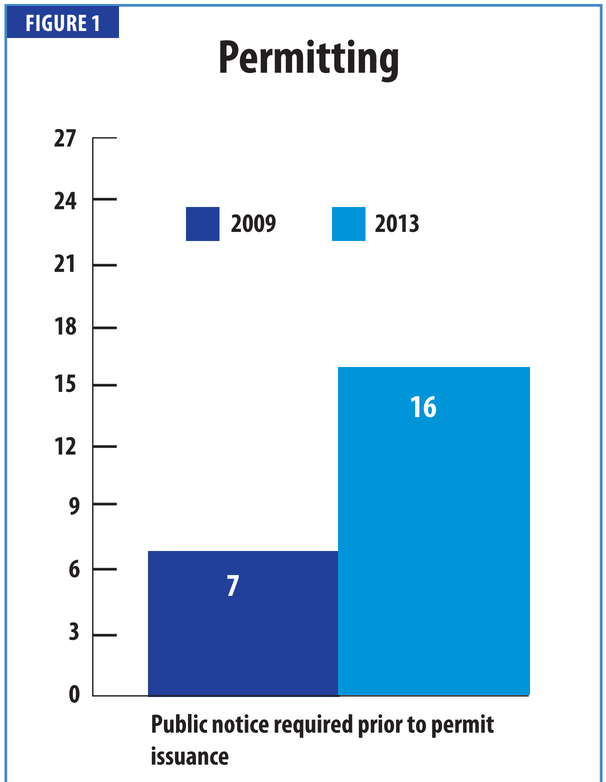
State oil and gas regulatory frameworks related to groundwater protection are evolving rapidly. Key trends are summarized below for the regulatory areas and related elements addressed in a 2013 survey of states, together with related considerations for regulators and policymakers.

Permitting

Since 2009, a significant number of states have added permitting requirements related to oil and gas operations, including requirements for public notice prior to issuance for some types of permits (Figure 1), and provisions to deny, delay, or revoke permits if applicants are not in compliance with the state's oil and gas law. In the latter half of 2013, four additional states had proposals to increase public notification prior to permit issuance, evidencing a trend in which states seek to increase transparency in the regulatory process and provide additional avenues for stakeholder participation.

A second major trend is toward requiring a review of the geology around a wellbore to evaluate potential subsurface fluid pathways that could interfere with full containment during well completion operations. Area of review (AOR) evaluations, modeled after those used in the UIC program, are currently required in four states and several others are now considering such a requirement. Similarly, more states are asking operators to provide analysis of stratigraphic confinement when well stimulation occurs close to a protected water zone or in uncertain geology.

FIGURE 1



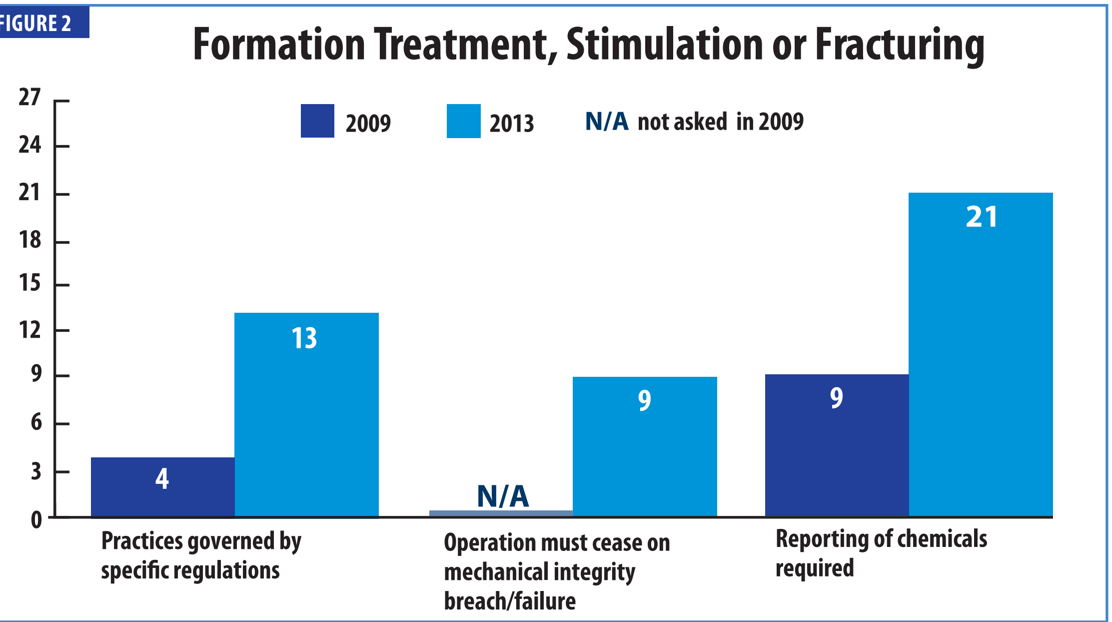
Considerations:

- Continue trends toward additional transparency in permitting, the use of permitting as a compliance mechanism, and toward requiring an analysis of AOR and confining zones with respect to particular well operations such as hydraulic fracturing

Formation Treatment, Stimulation, or Fracturing

While well integrity regulations remain the primary tool that regulators use to protect the environment during well operations including stimulation, a growing number of states are now directly regulating the practice of hydraulic fracturing, focused especially on disclosure of chemicals used in the practice, public and regulator notice of hydraulic fracturing activity prior to commencement, and monitoring and reporting of pressures during hydraulic fracturing. Other emerging trends include requirements

FIGURE 2



for baseline water testing prior to, and monitoring following, hydraulic fracturing treatment; water sourcing reporting; cement evaluation reporting; mechanical integrity testing prior to hydraulic fracturing treatment; and ceasing of hydraulic fracturing upon discovery of a mechanical integrity failure. (Figure 2)

Looking forward, proposed hydraulic fracturing regulations focus on regulator notification to allow witnessing of completions; prohibitions on chemical use; disclosure requirements for base water and chemicals used; mechanical integrity testing prior to treatment; and operational monitoring, especially of pressures, during treatment. Eight states had proposed rules on these issues as of late 2013. Of these issues, chemical disclosure has the most widespread regulatory activity, with six states conducting rulemakings on the issue. In fact, chemical disclosure has been one of the popular subjects for rulemakings in recent years, and nearly every major oil- and gas-producing state has addressed or is addressing this issue.

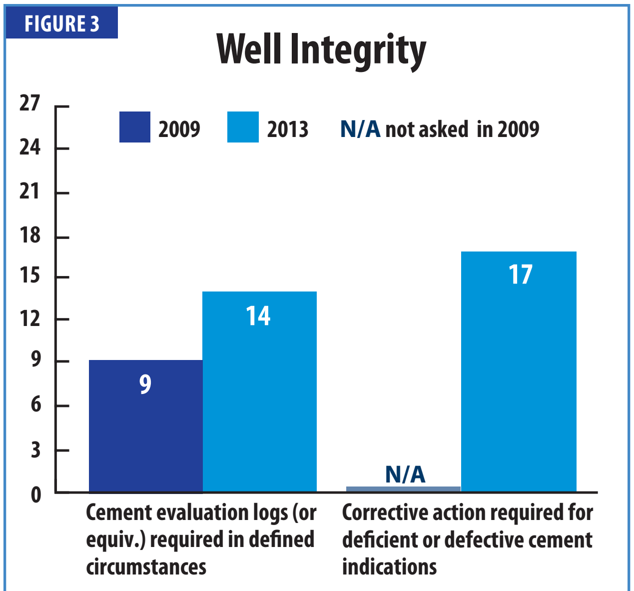
Considerations:

- 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

Well Integrity

Proper well integrity is essential to protecting groundwater during the construction, completion, and production phases of well development. In recent years, some states have incorporated major revisions into their well integrity programs, including enhanced cementing requirements, increased agency attention to the depths of groundwater when reviewing permits, more detailed specifications for intermediate casings, adoption of casing standards, requirements for corrective action when there is evidence of cement failure, requirements for the use of cement evaluation logs under specifically defined

FIGURE 3



circumstances, and requirements for notification prior to casing and cementing. (Figure 3)

Many states have suggested they will continue to update their well integrity rules in 2014 and beyond. Recent trends suggest that states will focus on ensuring that casing and cementing is sufficiently robust and properly tested for conditions faced during stimulation and production, and on isolation of sections of the subsurface containing protected water, corrosive zones and flow zones capable of over-pressurizing the annulus. In late 2013, three states had pending rulemakings that would require corrective action if a deficiency is encountered during cementing.

Considerations:

None of the above policies are pursued universally. Additional aspects of well integrity for wider consideration might be:

- More 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

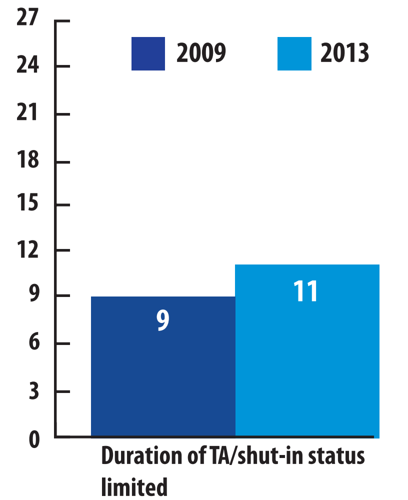
Temporary Abandonment (TA)

Most states allow operators to temporarily abandon wells following completion, in order to prevent the plugging of wells that may have future economic value. Recognizing that temporary abandonment (TA) provisions can sometimes be misused by operators to delay timely plugging of unproductive wells, state regulators are increasingly imposing stringent time limits on TA status, while regularly renewing TA status under specific circumstances.

In 2009, 25 states allowed the practice of temporary abandonment and, of these, 24 required both a prior authorization for, and renewal of, TA status. By 2013,

FIGURE 4

Temporary Abandonment



one additional state required prior authorization for TA status and two additional states had established a limitation on the duration of TA status. (Figure 4) Continuing this trend, two more states are currently seeking to limit the duration of TA status.

Well Plugging

Well plugging principles have been established for decades, and all 27 states regulate the practice to varying degrees. Most states have very specific requirements concerning the materials and placement methods for plugs. In 21 states, operators must submit a plugging plan in advance. In 26 states, a prior notice to the regulatory agency is required before a well can be plugged.

Positive trends in this area include the increase in states specifying the method of plugging and imposing requirements for more detailed reporting. In a corresponding trend, more states are allowing operators to submit cement tickets in lieu of witnessing. (Figure 5) Unlike field inspector witnessing, a cement ticket is not a verifiable demonstration of either the amount or quality of the cement used, nor does it describe the methods used to place that cement.

FIGURE 5

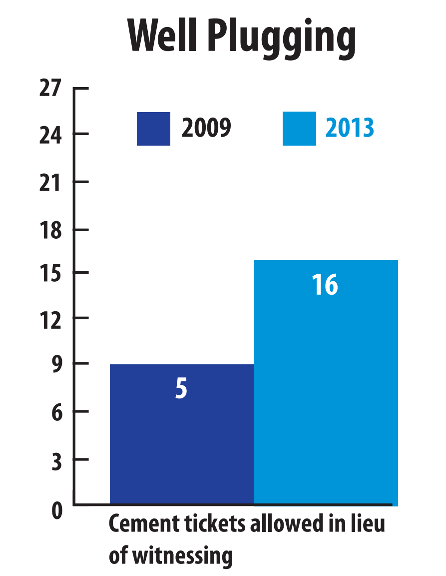
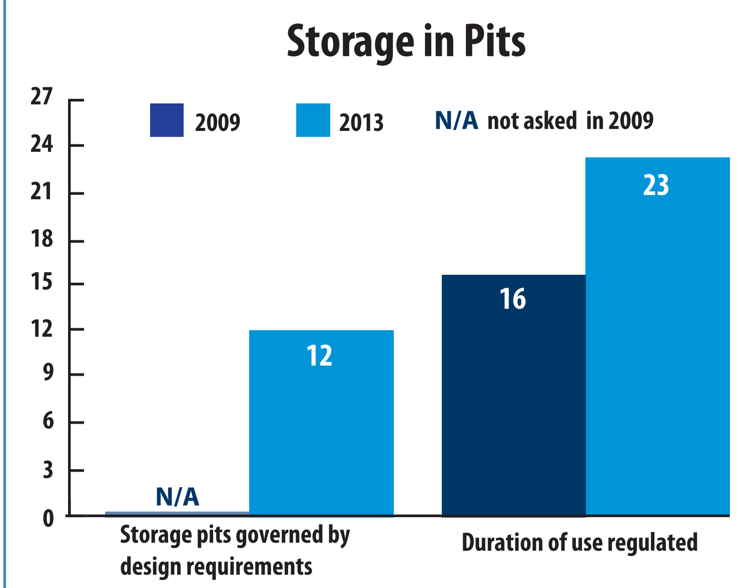


FIGURE 6



Considerations:

- Witnessing plugging operations in lieu of allowing the submission of cement tickets to satisfy reporting requirements
- Cement placement across all protected water zones

Storage in Pits

Although the use of steel tanks is becoming more prevalent, excavated pits are still the most common means of storing fluids during drilling and operations. The number of states with competency standards for pit liners increased significantly from 2009 to 2013, along with the number of states with a freeboard requirement. In addition, more states are specifying duration of use, and several have added requirements related to pit closure, including prior authorization, landowner notice, and soil sampling. (Figure 6)

There is a growing trend toward the use of modular, site-assembled storage structures. Substantial environmental risks may be associated with modular storage structures if they are not properly designed, constructed, and maintained, given that failure will typically be of a catastrophic nature with an instantaneous and total loss of containment. Several states are in various stages of developing regulations to address the design, construction, and operation of modular storage structures.

Considerations:

- Permitting or authorization based on characteristics of the fluids stored
- Specific design, construction, and operation requirements including liners, freeboard, leak detection, duration of use, and operator inspection and maintenance
- Siting restrictions taking into consideration surrounding land use, proximity to drinking water sources, 100-year flood plain boundaries, and separation from confined and unconfined groundwater
- Closure specifications including disposition of fluids, solids, and liners from the pit, and site restoration

Storage in Tanks

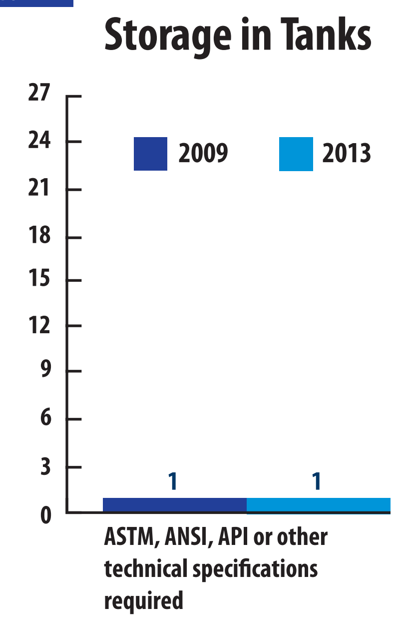
Because tanks may be more likely than pits to fail in a catastrophic manner and release their total contents in a single event, the use of secondary containment is commonplace. In 23 states, tank batteries must be surrounded by a secondary containment dike. Further, 21 of the states requiring a containment dike also specified the capacity of the dike. Apart from secondary containment provisions, many states do not specify tank design, siting, or operation requirements. However, five states have specific tank construction requirements based on fluids being stored, and one (Colorado) requires the use of Underwriters Laboratories (UL) or American Petroleum Institute (API) standards, as applicable. (Figure 7)

In most states, the absence of a specific requirement or standard allows for the use of a multitude of materials such as plastic, wood, concrete, steel, and fiberglass, not all of which are appropriate for the storage of particular types of fluids. For example, in some instances, produced water can be stored in uncoated steel tanks. Since produced water is corrosive to varying degrees, storage in unlined steel tanks can lead to leaks and tank failures over time. In some cases, the use of cathodic protection is necessary to prevent metal oxidation with resultant degradation. Development of tank construction standards is evolving and more states are reviewing their current standards with an eye toward implementing more specific requirements.

Considerations:

- Permitting or authorization based on the characteristics of the fluids being stored
- Specifications that address design, construction, and operation of tanks, including tank materials, overfill prevention, spill containment, leak detection, and operator inspection and maintenance
- Siting evaluation taking into consideration surrounding land use, proximity to drinking water sources, and 100-year flood plain boundaries
- Closure specifications including disposition of fluids and solids, tank removal and disposition, and site restoration

FIGURE 7



Produced Water

The vast majority of produced water is re-injected underground through an injection well permitted under the Underground Injection Control (UIC) program.[2] Other options for disposal include treatment at a permitted facility; or recycling or reuse, which likely will be preceded by some form of treatment. Produced water is typically transported by truck unless a nearby disposal facility or enhanced recovery project is available to accept the water. Less than half of the oil and gas agencies surveyed permitted transporters or required the recording of the volume of produced water transported off-lease.

The treatment and reuse of produced water is becoming more prevalent and warrants in-depth review of current regulatory programs. In some states, such as Texas, new regulations have been developed to regulate and facilitate the practice of oilfield recycling. These regulations address storage in pits, disposal methods, management of waste haulers, and the use of commercial versus noncommercial facilities for recycling. An emerging issue in 2013 was the characterization of side streams from produced water treatment, with two oil and gas states addressing the topic.

2 Ground Water Protection Council, *Injection Wells: An Introduction to Their Use, Operation & Regulation* (Sept. 2013).

Considerations (Transportation of Produced Water for Disposal):

- Permitting or licensing of produced water transporters and the recording of the volume of produced water transported off-site
- Use of MOU/MOA between oil and gas agency and other state agencies where the oil and gas agency does not directly regulate transportation of produced water

Considerations (Produced Water Recycling and Reuse):

- Chemical characterization and management of side streams
- Careful regulation of use of produced water for purposes other than disposal or well stimulation
- Design, construction, operation, and removal standards for recycled water pipelines
- Use of MOU/MOA between oil and gas agency and other state agencies where the oil and gas agency does not directly regulate water recycling and reuse

Exempt Waste Disposal (Drill Cuttings and Tank Bottoms)

Wastes such as drill cuttings and tank bottoms require a different disposal strategy than produced water. While some of these solid wastes are re-injected under the UIC program, most are buried onsite or transported to an off-site landfill. Other alternatives for solid waste disposal may include reuse for road base material, dust suppression, or bio-remediation using land-farming techniques. Surface management and land application of wastes is regulated in 23 states, either through direct control by the oil and gas agency or another state environmental agency.

Considerations:

- Manifests for off-site disposal where appropriate

Spill Response

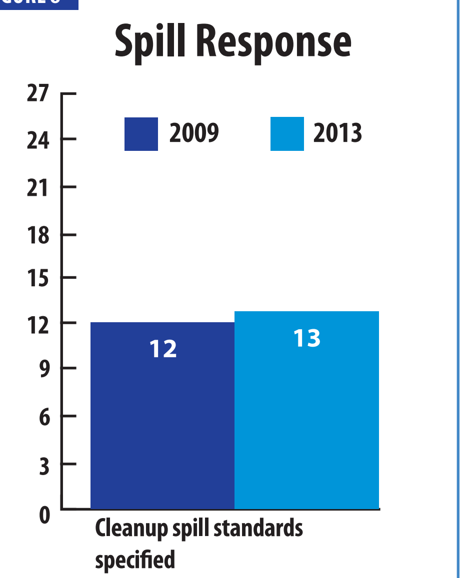
The vast majority of states (23) have regulations related to spill response that include agency notification on spills and on-site spill remediation. Requirements for reporting a spill of oil and gas products or wastes are often dependent on the nature, location, extent, and volume of a spill. Thirteen states specify a clean-up standard for spills. (Figure 8)

With public scrutiny of oil and gas operations, and especially accidents, at an all-time high, rapid and effective spill response is on many regulators' agenda. Five states had rulemakings concerning spill response in late 2013, making it the most common topic of rulemaking during this period after chemical disclosure. Elements addressed in this round of rulemaking included timeliness of notification to regulator and surface owner, volume triggers, on-site remediation rules, and clean-up standards geared toward the substances spilled and the medium where the spill occurs.

Consideration:

- Clean-up standards should be established that are relative to the characteristics of the material spilled and impacted media

FIGURE 8



Regulatory Practices and Programs

In preparing this report, states were surveyed regarding certain aspects of their oil and gas regulatory programs, including program staffing, budgets, permitting, inspections, orphan sites programs, and witnessing of field processes, as well as use of supplementary documents like practice manuals, director's letters, environmental impact statements, and other documents that fall outside the traditional bounds of notice-and-comment regulation. Three essential factors in an effective regulatory program — regulatory coordination, data management, and foundational scientific research — were identified, with considerations for regulators and policymakers.

Regulatory Coordination

Effective regulation of E&P activities requires that state, local and federal regulatory agencies communicate routinely and define the boundaries of each agency's responsibilities. To facilitate this, memoranda of agreement or understanding (MOAs or MOUs) should be considered that describe the jurisdictional nexus between regulatory agencies within a state; between state, local and federal agencies; and between individual states. These agreements should be sufficiently detailed and clear to become the framework for day-to-day operational regulation.

Considerations:

- Interagency and interstate communication on issues of regulatory importance should continue to remain a priority
- Agreements should be incorporated into procedural documents agencies use to implement regulatory programs
- Coordination of action at the field level should be stressed and should be incorporated into the agency policy to avoid jurisdictional gaps that could result in environmental harm

Data Management

A regulatory agency's ability to collect, store, extract, analyze, and accurately present data is essential to the protection of water resources. While much environmental compliance monitoring data is not yet in electronic format, states are making steady progress in improving data management. In 23 states, the system used to manage regulatory data is the *Risk Based Data Management System* (RBDMS). This modular data system, developed by the GWPC, can store data on numerous aspects of state oil and gas regulation. Originally developed as a data system for state UIC programs, the current versions of RBDMS are capable of capturing data related to oil and gas activities including well completion, production, operation, compliance, and plugging. One of the latest RBDMS modules (RBDMS Environmental) is designed to capture environmental indicators including water quality parameters. The RBDMS system is constantly evolving and the GWPC is currently part of an effort to develop a data portal capable of linking disparate databases for the purpose of analyzing and presenting data from many different sources. In addition to RBDMS, the GWPC and the IOGCC have developed a web-based chemical registry system (FracFocus ©). This system is used by 16 states to manage the regulatory disclosures of chemicals used in the process of hydraulic fracturing.[3] The system, which contains over 77,000 records and is used by more than 650 companies to report chemicals, provides chemical disclosure information to the public through a web-based searchable database.

Considerations:

- Rapid and comprehensive access to regulatory information at both the office and field levels should remain a priority and processes that enhance this access should be implemented whenever possible
- Consideration should be given to providing information to the public through web enabled systems, both to decrease the level of

3 As of July 2014, six other states are proposing to either require or allow disclosure to FracFocus.

effort currently expended in fulfilling public records requests, and to improve regulatory transparency

- Connecting disparate data systems to provide a broader range of information and facilitate data exchange should be a priority

Foundational Scientific Research Needs

Research into the scientific principles related to areas of concern is a critical part of determining the relative risk of activities.

Dissemination of the information learned from research is necessary to help the regulatory community evaluate and, where needed, take appropriate action to protect water resources.

Considerations:

- Basic scientific research related to field operations that could potentially affect the protection of water resources should be encouraged and facilitated. Specific areas of research needed include but are not limited to:
  - Evaluations of the risks associated with NORM and Technologically Enhanced Naturally Occurring Radioactive Material (TENORM);
  - Evaluations of the extent, causes and risks of induced seismicity;
  - Comprehensive and focused research into the relative risk to surface water and groundwater posed by the practice of hydraulic fracturing and E&P operations;
  - Continued research into the characterization and occurrences of stray gas migration relative to natural conditions and human activities.
  - Characterization of formation water and produced water in order to: (1) facilitate the use of brackish water supplies and recycling; and (2) inform regulatory oversight of treatment and discharge when produced water is neither recycled nor sent to disposal wells
- Conferences and symposia focusing on the results of scientific studies should be held to disseminate information learned through research

Groundwater monitoring. Source, USGS

Background

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 and 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 general or specific in type. For example, a general rule might say "The operator must use an amount of cement sufficient to protect all fresh groundwater zones," while a specific 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 an important role in the regulatory process. General 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. Specific 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 that state rules are being followed by the regulated community. 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.

Purpose

In 2009, the GWPC published "*State Oil and Natural Gas Regulations Designed to Protect Water Resources.*"[4] The purpose of that study was to describe the areas and related elements of state oil and gas regulations that protect water and to describe the regulatory language governing those areas and elements. The study concluded with a list of

4 Ground water Protection Council, State Oil and Natural Gas Regulations Designed to Protect Water Resources (Apr. 2009), available at http://www.gwpc.org/sites/default/files/state_oil_and_gas_regulations_designed_to_protect_water_resources_0.pdf.

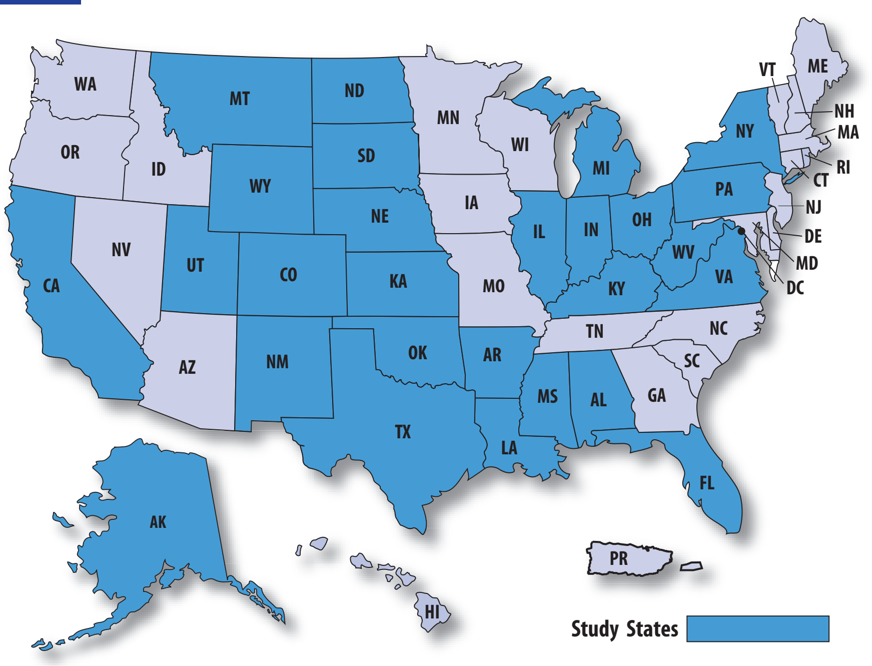
suggested actions for consideration by state policymakers as they engage in continuous improvement of their regulatory frameworks (reprinted in Appendix 12).

In this update, the GWPC builds on the analytical work conducted in 2009 and documents the intervening enhancements in regulatory programs made by many states in response to increased oil and gas E&P activities.

Scope

For comparability purposes, the same 27 states reviewed in the 2009 study were included in this update. (Figure 9)[5] Appendices 8 and 9 list primary state contacts related to oil and gas regulation, including e-mail addresses, and hyperlinks to state regulatory websites. This update reviews rules published by state oil and gas regulatory agencies as of July 1, 2013. The report also summarizes proposed rules for each area or element, documenting rules being promulgated within official state regulatory development processes as of September 1, 2013.[6]

FIGURE 9



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

In addition to the rules review, each state was asked to complete a survey that focused on selected regulatory program areas to gain a more complete understanding of regulatory processes. This survey expanded the scope of the 2009 study by surveying not only current and proposed rules, but also selected areas of state oil and gas regulatory programs. Areas reviewed include program staffing, budgets, permitting, inspections, orphan sites programs, and witnessing of field processes, as well as supplementary documents like practice manuals, director's letters, environmental impact statements, and other documents that fall outside the traditional bounds of notice-and-comment regulation. Nineteen states responded to the survey.

While the updated report utilizes many of the same regulatory areas used in 2009, it also expands the scope of the review, modifying or adding regulatory areas and related elements as necessary. In particular, modifications have been made in the areas of well integrity, completion, pits, and tanks, and areas have been expanded in the waste section to cover disposal methods, transportation, and recycling. The new areas help provide a more complete picture of state oil and gas regulatory frameworks for protecting groundwater and enable a more fine-grained analysis of changes in regulation over time. As technologies and practices evolve, future versions of this report will add areas and related elements to its coverage to stay current and relevant for policymakers. Appendix 3 shows the matrix of regulatory areas and

5 For the 2009 study, states were selected based on the latest available list (2007) of producing states compiled by the U.S. Energy Information Administration. Of the 33 states in the EIA list, 27 represented more than 99.9% of all oil and natural gas produced in the United States. Since it was not possible to assign a weighted value to each oil or natural gas producing state, it was necessary to neutralize the disproportionate effect that states with very minimal production would have had on the data analysis. This was accomplished by removing any state that accounted for less than 0.1% of both oil and natural gas production. Consequently, 27 states were included in the 2009 study. The same 27 states were reviewed for the 2013 update even though, between 2009 and 2013, there had been some shifting in the state rankings. To insure comparability with the 2009 study, it was felt that these changes were not significant enough to modify the selection of states. The 2013 EIA list of oil and gas producing states, sorted by oil production ranking is included in Appendix 2 of this report.

6 The proposed rules reviewed here include both entirely new and revised rules.

7 The counts from the matrix cover state rules only. No policies, guidelines or other documents are included. Although the wording changed slightly between the 2009 and 2013 reports, the number provided in the table is from the 2013 language.

related elements reviewed for this update, along with their corresponding state rule counts for both 2009 and 2013.[7] Where possible, this report presents comparisons between the 2009 and 2013 findings for each element; where the areas or elements were new or differed, only the 2013 results are shown.

As with the 2009 study, each state's rules were compared to a set of 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. 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 and 2013 Studies

In conducting this update to the 2009 study, GWPC modified or added regulatory areas as needed to expand the scope of the review.

Table 1

2009 Areas	2013 Areas
Permitting	Permitting
Well construction	Well integrity
Hydraulic fracturing	Formation treatment, stimulation, or fracturing
	Production operations
Temporary abandonment	Temporary abandonment
Well plugging	Well plugging
Tanks	Storage in tanks
Pits	Storage in pits
Waste handling and spills	Transportation of produced water for disposal Produced water recycling and re-use Exempt waste disposal Spill response

As noted in the 2009 report, definitions of "protected groundwater" differ across the states 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 will be the subject of a companion report to be published by the GWPC at a later date.

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

Exclusions

In addition to state oil and gas agencies, numerous other local, state, and federal agencies may, in some states, exercise significant control over oil and gas activities. Unfortunately, time and resource constraints did not allow the survey to account for interactions between the oil and gas agency and other 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 Indiana Division of Oil and Gas has a MOA with the Indiana Department of Environmental Management regarding jurisdiction over spills of oil and produced saltwater. This MOA defines the boundaries of control for each agency and lays out the communications structure between agencies for the management of spills (Appendix 7). Such agreements are commonplace in many states and reflect a coordinated approach designed to increase environmental protection and emergency response. In some western states, 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. In some cases the state will defer to the BLM while in other cases there is a dual layer of regulatory control. For example, in a 2012 survey of state oil and gas agencies, the GWPC found that 13 of 15 states issued a separate state permit for oil and gas wells on federal land.[8] In such cases it is not uncommon for the state and BLM to have an MOA or MOU.

As with the 2009 study, Underground Injection Control (UIC) programs were not reviewed in 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-specific issues such as induced seismicity and a comprehensive review of the UIC regulations and programs was not conducted.

8 Survey of states regarding permitting on federal land, GWPC, 2012

EVOLUTION OF OIL AND GAS REGULATION

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 developed primarily 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 water and land resources were being unnecessarily contaminated by oil field practices. It also shows how state oil and gas environmental regulations have been philosophically influenced by of the influx of federal environmental laws during the past thirty-five years in some ways, but not in others. Appendix 16 details the history of oil and gas regulations from its beginnings in the early part of the 20th century.

Source Unknown

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 related oil and gas 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.

In recent years, 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. In fact, from 2009 to 2013, an estimated 82 groundwater-related rulemakings affecting upstream oil and gas E&P were finalized across the United States, including hundreds of discrete rule changes, with many more rulemakings currently ongoing and proposed. As efforts increase to bring regulations up to speed with rapidly changing technologies and other regulatory drivers continue to directly impact the industry, continued growth and change to state oil and gas regulatory programs is likely over the next five years and beyond. 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. For example, in 1980 the Ohio Water Development Authority commissioned a report by Elmer Templeton and Associates, Inc. to estimate the volume of "salt brines" (produced water) generated annually by Ohio E&P activities and to recommend environmentally acceptable disposal options.[9] This report provided the foundation for:

9 Templeton, E.E., *Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas* (1980) (A report prepared by Elmer E. Templeton and Associates, Inc. for the Ohio Water Development Authority).

- Enforcement actions to eliminate earthen pit produced water storage;
- Shifts in policy towards establishing deep injection as the preferred method of disposal;
- Pursuit of Class II underground injection control primary enforcement authority from EPA; and
- Statewide debates that led to the passage of comprehensive produced water management legislation (Am. Sub. HBV 501) enacted in 1985.[10]

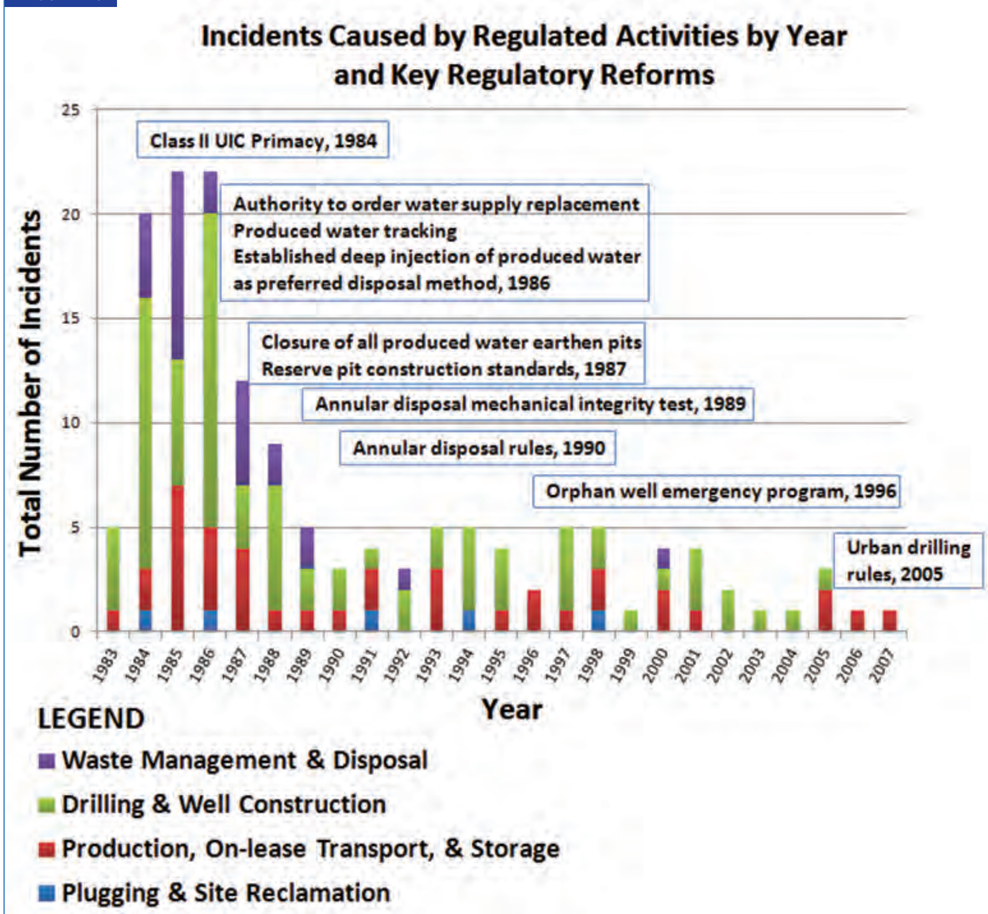
Regulatory experience and activity is one of the primary drivers of regulatory reform. Based on the knowledge of past problems and investigative findings, regulatory agencies will often define new boundaries for regulatory management. A review of the history of oil and gas activity can be used to evaluate the effectiveness of current regulation and to provide the basis for regulatory change. For example, in the 1970s the use of evaporation pits was 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 states and the lining of these pits elsewhere.

The public has also played an important 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.

Past external reviews of state programs conducted by organizations such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) were 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 American Petroleum Institute, Environmental Defense Fund, and others have led to improvements in regulatory programs resulting in increased environmental protection. In 2013 the GWPC and the Interstate Oil and Gas Compact Commission (IOGCC) formed the State Oil and Gas Regulatory Exchange (SOGRE), as part of the States First initiative, that will assist states with reviews and updates of regulations, provide technical training, and facilitate technology transfer.

Figure 10 is an example of regulatory response based on experience from the Ohio Department of Natural Resources, Division of Oil and Gas Resources Management (DOGRM).[11]

FIGURE 10



Source, Adapted from Ohio DOGRM

10 Scott Kell, Ground Water Protection Council, *State Oil and Gas Agency Groundwater Investigations and Their Role in Advancing Regulatory Reforms, A Two-State Review: Ohio and Texas* (Aug. 2011).

11 Ibid..

ELEMENT REVIEW AND FINDINGS

As previously noted this report includes a review of regulatory areas such as permitting, well treatment, well integrity, plugging, etc. The following represents the findings for each of the areas and related elements listed in Appendix 3.[12]

Permitting

Permitting is the process of authorizing the drilling and completion of a well for oil and gas purposes and other activities associated with 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 states, well construction plans are reviewed and approved through other processes subsequent to issuance of a drilling permit; however, all states 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 states, the permit covers not only the drilling of the well but other activities including well treatment, hydraulic fracturing stimulation, storm water controls, 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. Lease facility plans must be approved by the Arkansas Oil Conservation Commission and Arkansas Department of Environmental Quality before drilling can begin. Other states may authorize such activities through a series of permits.

All 27 oil and gas producing states in the study have permitting requirements governing the locating, drilling, completion, and operation of oil and gas related wells. Authority to require permits for the drilling of oil, gas, and service wells (injection wells and others) is typically delegated by the state legislature to an oil and gas division, commission, or board. Heads of commissions or oil and gas agencies are sometimes elected though most are 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 who are technically trained and qualified to review applications for both conservation and water resource protection purposes.

While all 27 states can deny a permit if the application contains insufficient information to make a technical determination, 13 also have the authority to deny a permit for other reasons such as outstanding violations or lack of a state license. For example, in Ohio, if the chief issues an order finding that an operator has committed a Material and Substantial Violation or is engaged in an activity that presents an imminent danger to public health or safety, the chief may deny, suspend, or revoke permits and associated operations. In Illinois, an unabated Director's Order serves as a permit block to that permittee.

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 provided in a lease, which details the rights and responsibilities of the mineral rights owner and the oil and gas operator.

12 In order to better explain the findings, areas 10 and 11 from the appendix were combined in this section of the report into a single section that discusses several aspects of produced water management.

Scope of Permitting Area Review

This study reviewed state regulations with respect to seven types of permits or authorizations:

Table 2

Permit Type	Includes:
Drilling, re-drilling, workover, and well conversion	Permits to drill new oil or gas wells, re-drill plugged wells, workover existing wells, or convert wells from one type to another
Plugging	Notices of Intent to Plug and Plugging Plan approvals
Treatment, stimulation, or fracturing	Permits to hydraulically fracture, acidize, or otherwise stimulate a new or existing oil or gas well
Land application of exempt waste	Permits to apply RCRA Subtitle C exempt waste to road and lands for the purposes of dust control, disposal, or bio-remediation
Stormwater	Permits to construct well-sites and surface facilities for the purpose of preventing stormwater runoff during drilling operations
Discharge to Publicly Owned Treatment Works	Permits to take RCRA Subtitle C exempt waste such as produced water or hydraulic fracturing flowback fluids to a publicly owned water treatment facility for eventual re-use or surface discharge
Discharge to commercial Class II disposal well	Permits for subsurface injection of produced water and other RCRA Subtitle C exempt waste into commercial wells permitted for the purposes of disposal or enhanced recovery under the underground injection control program

2009-2013 Comparisons

In 2009, all 27 states issued permits for drilling, re-drilling, workover or well conversion. In 2013, this number did not change. Between 2009 and 2013, two states adopted permitting requirements for well treatment, stimulation, or hydraulic fracturing, which brought the total number of states with separate permitting requirements for this sub-element to 10. Additionally, two states added separate permitting requirements for storm water management at wellsites, bringing the total number of states in 2013 to seven. One state added a permitting provision for the land application of RCRA Subtitle C exempt waste, which brings the total number of states in this element to 14. For the 2013 update, the elements of discharge to Publicly Owned Treatment Works (POTWs) and Class II Underground Injection Control (UIC) were added. As of 2013, six states had permitting requirements for discharge to POTWs and 25 permitted the injection of produced water into commercial Class II UIC wells as a means of disposal.[13] Figures 11 and 12 show a select group of elements reviewed.

13 Three states in the study (New York, Pennsylvania and Michigan) do not have primary enforcement authority for the Class II Underground Injection Control program. However, Michigan runs a concurrent and largely duplicative state Class II UIC program and is thus counted as one of the 25 states with Class II disposal regulations.

FIGURE 11

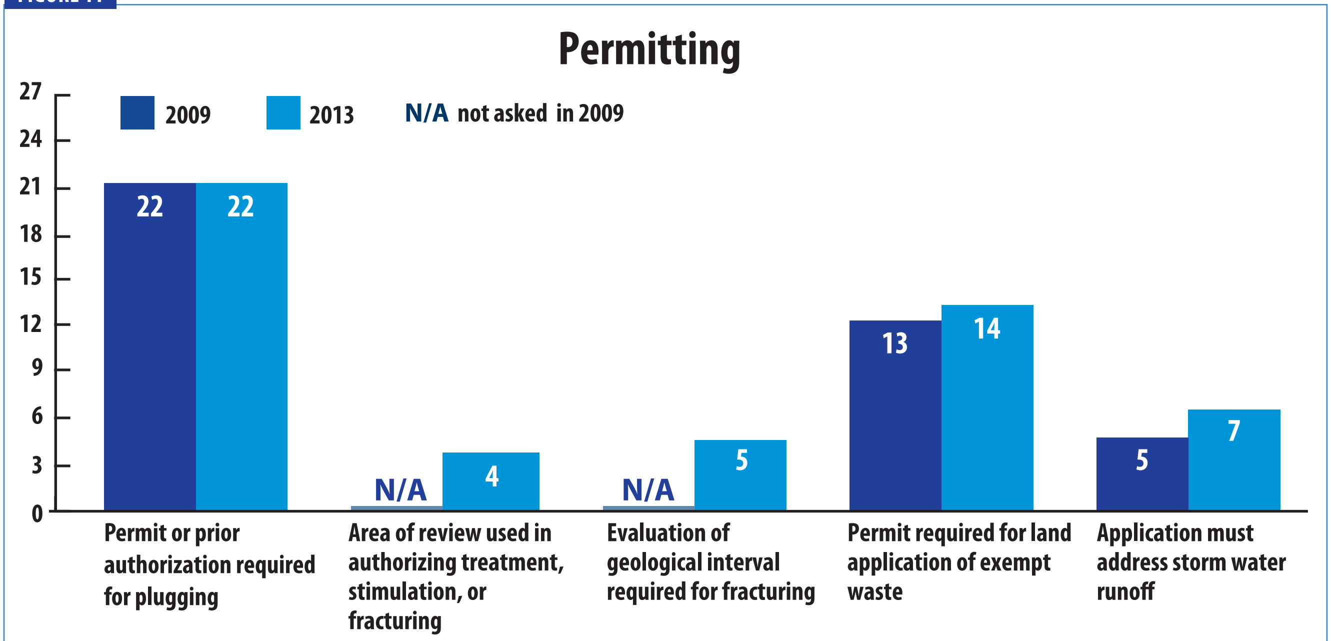
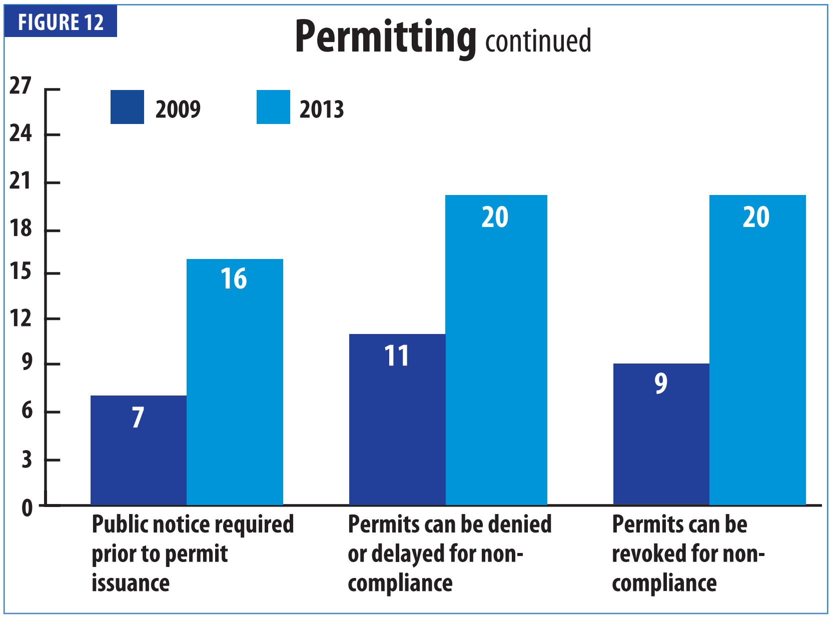


FIGURE 12



2013 Regulatory Proposals

Several states have adopted rules that require applicants to conduct an investigation of wellbores and natural phenomena proximate to the proposed well that could potentially act as conduits for fluid migration from the stimulated zone to protected waters (sometimes referred to as an "Area of Review"). If this review identifies potential conduits, the applicant must modify their drilling and/or hydraulic fracturing programs, or take other prescribed precautions to mitigate the risk of protected water contamination. Some states have made this evaluation a standard part of the permit application review process, thereby protecting water, but not through a rulemaking requirement imposed upon applicants.

States are also increasing public notification requirements, such as written notices to real property owners and public meetings, for specific types of permit applications prior to determination — four states had proposals on this topic in the latter half of 2013. As public interest in oil and gas development has increased in recent years, states are seeking to improve the transparency of process by providing additional avenues for stakeholder participation.

Formation Treatment, Stimulation, or Fracturing

Well treatments fall into two primary categories:

- **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.
- **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

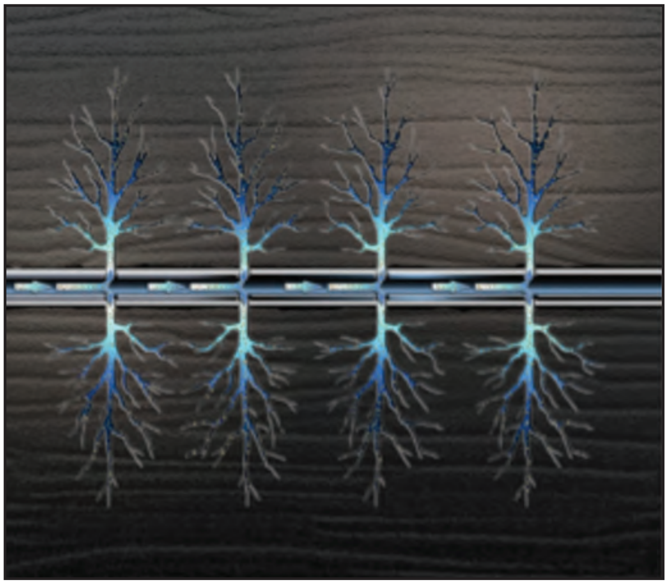
Hydraulic fracturing can be a critical component of well development; without it, there may be insufficient flow pathways for oil or gas to get to the wellbore. The process involves pumping fluid into a formation under sufficient pressure to create fractures in the rock matrix, allowing oil or gas to 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. A single fracture job can increase the pathways available for fluid migration in a formation by as much as 270 times in a vertical well and much more in a horizontal well.[14]

Hydraulic Fracturing Job Circa 1950

Source, FracFocus

The first commercial application of hydraulic fracturing as a well treatment technology designed to stimulate the production of oil or gas likely occurred in either the Hugoton field of Kansas in 1946

14 Belgacem Chariag, Schlumberger, *Maximize Reservoir Contact*, E&P (Hart Energy), Jan. 2007.



Representation of a fracture pattern in a generic unconventional shale zone
Source, FracFocus

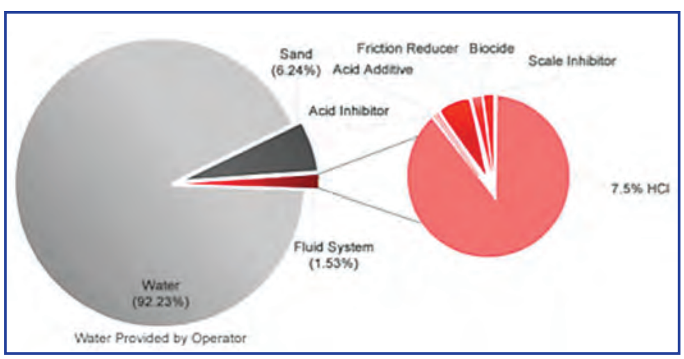
or near Duncan, Oklahoma in 1949. In the ensuing 60 plus years, hydraulic fracturing has become a routine technology that is frequently used in the completion of gas wells, especially those drilled into unconventional reservoirs such as tight shale. In a paper written for the Society of Petroleum Engineers it was estimated that, since 1949, over 2,500,000 fracture jobs have been conducted on oil and gas wells worldwide.[15]

The only alternative to fracturing the 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 very large numbers of wells located within a very small area to equal the production of even a single hydraulically fractured well, generally this alternative is neither environmentally desirable nor economically viable.

A great deal of attention has been focused on the process of hydraulic fracturing. Media outlets, environmental groups, citizen's 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 natural gas is viewed as good energy policy. To the oil and gas industry, "hydraulic fracturing" generally is limited to the actual process of pumping fluids and proppant under pressure to fracture the rock. To others, hydraulic fracturing has become a nebulous 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 hydraulic fracturing. Regardless, it is important to note that any misunderstanding of the term "hydraulic fracturing" does not minimize the importance of regulation with respect to the entire E&P process; which must be addressed in order to protect water resources.

Fracturing Fluids

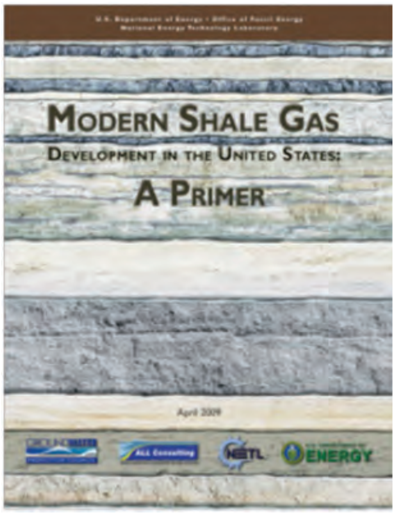
Fracturing fluid formulations may be based on acid, gel, water, or other media such as carbon dioxide or nitrogen foam. Most fracturing work is conducted using water-based fluid. In addition to water, fracturing fluids typically contain an array of additives, each designed to serve a particular function. 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.[16] This type of fracturing process is often referred to as a "slickwater" fracture. The use of additives is raised as one of the concerns about hydraulic



Typical ratio of fluids, by type, in a slickwater hydraulic fracturing fluid
Source, ALL Consulting, updated 2011

15 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).
16 P. Kaufman, G.S. Penny, J. Paktinat, Critical Evaluation of Additives Used in Shale Slickwater Fractures, SPE 119900 (Nov. 2008).

fracturing.[17] 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.[18] However, some substances used in some hydraulic fracturing operations, such as ethylene glycol, or components of petroleum distillates, have been linked to negative health affects at certain exposure levels.



Shale Gas Primer Source, GWPC

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.[19] However, it should be noted that a toxicological evaluation of fracturing fluid chemicals based on their relative proportions in flowback fluids was not a part of this study. Such an evaluation would be needed to determine their relative risk.

Regardless of type or relative concentration of additives, it is important that they be prevented from entering groundwater and creating unnecessary risks to the environment. 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. While this may or may not become feasible, 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. Much work remains to be done in this area. Still, 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 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 USDWs (Appendix 4). In 2008, the GWPC conducted a follow-up survey, which found that in 25 states with potential coalbed methane production, diesel fuel was not being used to hydraulically fracture coalbeds that are USDWs (Appendix 1). Between 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[20] (Appendix 18) describing the criteria under which hydraulic fracturing would be considered a UIC activity requiring a permit. In practice, diesel fuel use has dramatically decreased for well stimulations of all types, including hydraulic fracturing of shale formations. For example, a recent review of FracFocus records of more than 12,000 wells fractured since June 1, 2013 shows that in only 18 stimulations was any one of the diesel fuels listed in EPA guidance #84 used.

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% to 18% solution of acids that include hydrochloric acid sometimes mixed with acetic, formic, fluroboric, and other acids.

17 Amy Mall, Sharon Buccino, Jeremy Nichols, *Drilling Down: Protecting Western Communities from the Health and Environmental Effects of Oil and Gas Production* (Oct. 2007) (Publication of the Natural Resources Defense Council).

18 Robert Porges & Mathew Hammer, National Ground Water Association, *The Compendium of Hydrogeology* (2001)

19 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).

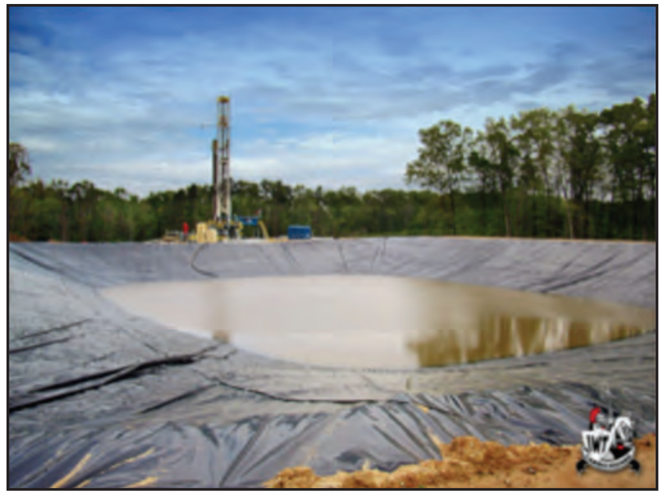
20 Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuel, Underground Injection Control Program Guidance #84, Office of Water (4605M) EPA 816-R-14-001, February 2014

Exposure Pathways

The exposure effects of additives that can be contained in the treatment fluids can be mitigated by reducing exposure pathways. Relevant to an analysis of exposure pathways is 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% to 70% of fracturing fluids are returned to the surface through the well casing.[21] 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.[22] The risk of endangerment to groundwater is further reduced by other physical factors such as:

- Well construction practices including state regulatory standards and industry guidelines;
- Vertical distance between the fractured zone and groundwater;
- 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; and
- Operational controls, such as the continuous monitoring of wellbore integrity during hydraulic fracturing operations.

While the wide 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.



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

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 to isolate them from soils and shallow groundwater zones and are subsequently removed from the location for recycling or disposal.

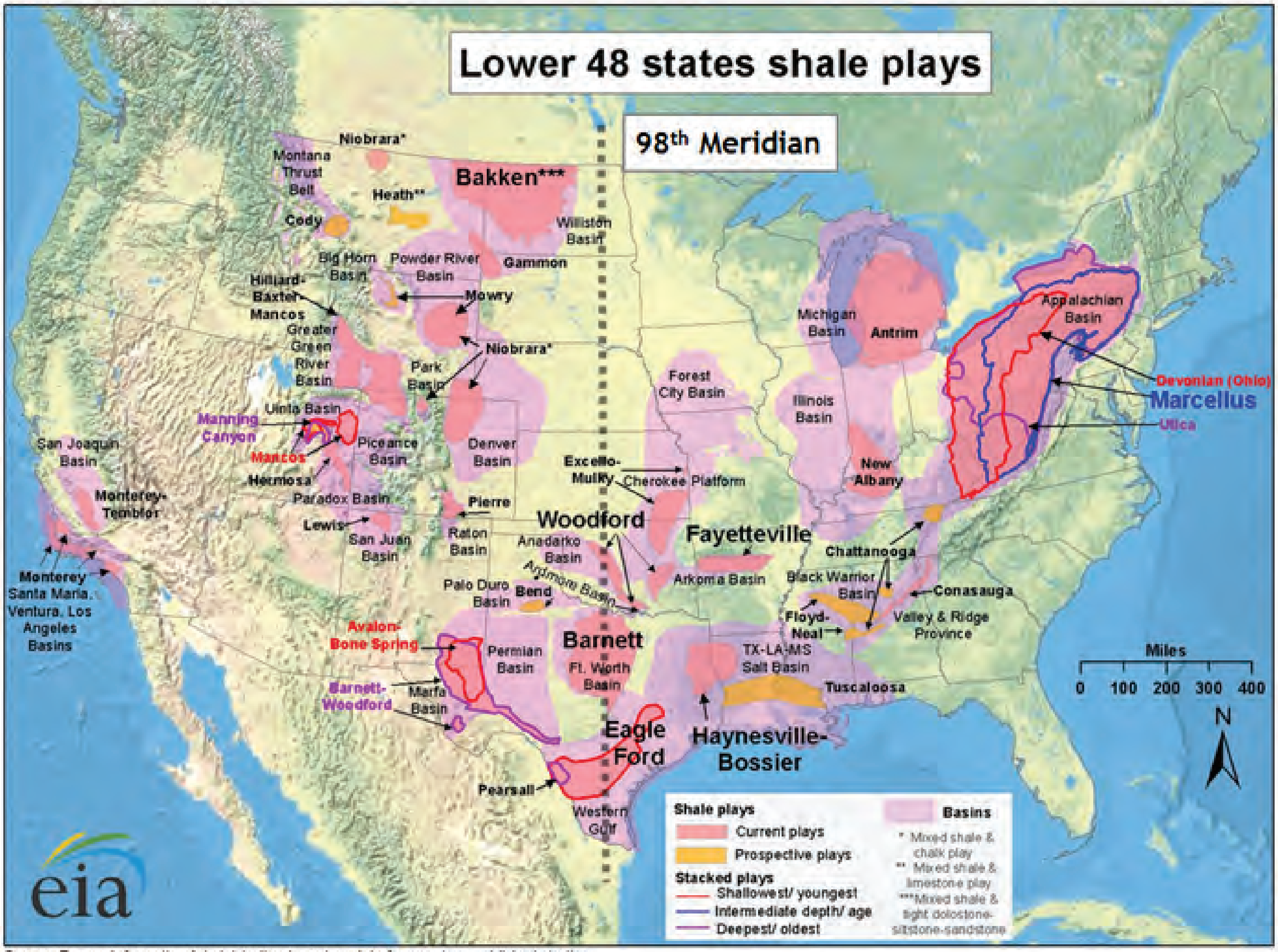
The ultimate fate of well treatment fluids returned to the surface is often determined by the availability of treatment and disposal technologies such as on-site or centralized treatment facilities and injection wells. Underground disposal via injection wells under the jurisdiction of a UIC program is 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 towards recycling and reuse of fluids is discussed in *Key Message 2: Emerging Issues.* For facilities west of the 98th meridian, on-site treatment and surface discharge, though rarely used, is also a disposal option, where authorized by EPA or a state regulatory agency.[23] East of the 98th meridian, on-site treatment and direct surface discharge is not allowed indirect discharge, however, such as treatment and discharge through publicly owned treatment works (POTWs) or centralized wastewater treatment facilities (CWTs), is sometimes conducted, provided the fluid will not cause the facility to violate its permit or any state

21 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).

22 USEPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* EPA 816-R-04-003 (June 2004).

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

FIGURE 13



Source: Energy Information Administration based on data from various published studies.

Shale plays in the lower 48 states

Source, Energy Information Administration

or national water laws or guidelines. (Figure 13)[24] Given the complications arising from this practice, some states, like Pennsylvania, are actively discouraging the use of POTWs for this purpose.[25] As part of this study, GWPC surveyed the study states regarding the use of POTWs for discharging production fluids including flowback water. Of the states responding, three indicated this practice was banned by regulation, five states did not have a regulation covering this disposal method but would not allow it as a matter of policy, and nine indicated it was either regulated by another state agency or would otherwise be allowed under certain circumstances. As noted in the permitting findings, as of 2013, six state oil and gas agencies had permitting requirements for POTWs accepting this waste.

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.[26] 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. 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

24 *See generally*, James Hanlon, Director, Office of Wastewater Management, EPA, *Natural Gas Drilling in the Marcellus Shale: NPDES Program Frequently Asked Questions* (Mar. 2011).

25 *See generally*, *Key Documents About Mid-Atlantic Oil and Gas Extraction,* EPA.gov, http://www.epa.gov/region03/marcellus_shale/ (last updated Jan. 31, 2014) (compiling documents regarding POTW acceptance of oil and gas wastewaters in Pennsylvania).

26 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).

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. There are cases, however, 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. However, a GWPC 2008 survey of state regulatory agencies found no determinations of contamination from the relatively shallow hydraulic fracturing of CBM reservoirs (Appendix 1). For this and other reasons, it is reasonable to conclude that the risk of fracture fluid intrusion into groundwater from the hydraulic fracturing of deeper conventional and unconventional oil and gas zones can be considered very low. 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;[27]
- Well construction requirements in most states 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 contained within the general provisions of state oil and gas laws, which contain 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 states such as Oklahoma have consolidated existing regulations with a relationship to well treatment into a single section of their regulatory language. Other states have introduced new direct regulation on acceptable chemical use, pre-stimulation reporting requirements, pressure monitoring standards, inspector notification requirements, and enhanced reporting requirements. Nevertheless, well integrity regulations remain the primary tool that regulators use to protect the environment from well stimulation.

Limitations and Requirements

As of 2013, some states had placed specific limitations on the well treatment process. The following is a partial list of well treatment requirements by rule or policy and examples of some states that implement them:

- Prohibitions against, or prior approval for, the use of some chemicals (Alabama and Wyoming);
- Minimum depths for fracturing (Alabama- Coalbed methane only);
- Geologic evaluations of the interval between the zone to be fractured and groundwater zones (Alaska, Indiana- Coalbed methane only, Mississippi, and Texas);
- A review of the area around the wellbore for natural and artificial conduits (Alaska, Indiana- Coalbed methane only, Michigan, Mississippi and, Ohio)

27 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).

- Requirements that fracture fluids be confined to the zone to be fractured (Alaska and Mississippi);
- Annular pressure monitoring during fracturing operations with job termination criteria (Ohio)
- Well pressure testing prior to fracturing (Alabama, Alaska, Montana, and North Dakota); and,
- Pressure limitations (Alabama, Alaska, and Montana).

These examples do not comprise the full list of requirements or states. Since the 2009 study, such limitations and requirements have become more commonplace in regulatory language and policy.

Disclosure and Reporting

In 2009, 10 states required some degree of reporting of chemicals used in wells. Most reporting was limited to a summary of the materials used and the intervals fractured. By 2013, upwards of 20 states have 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) of each chemical used. In 2010, 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. As the popularity and effectiveness of the website grew, several states decided to adopt the site as their means of regulatory reporting. Since early 2011 when the site was launched, 16 states have designated the FracFocus website as the official location for filing regulatory chemical disclosures (see Appendix 14- current as of February 2, 2014). The website allows the public to search for hydraulic fracturing disclosure records using such criteria as the state, county, operator, well name, date of job, chemical name, and Chemical Abstract Service (CAS)[28] number. It presents individual records in an Adobe pdf ® format which can be printed or downloaded. As of the writing of this report, over 900 companies have signed up to submit records to the system and more than 650 companies have submitted over 77,000 disclosures.

2009-2013 Comparisons

As noted in the chapter on supplementary documents below, the rules related to reporting do not always themselves contain a list of all of the information required by the agency. The forms used by the agency are, therefore, critical to an understanding of what the state requires with respect to reporting. For both the 2009 and 2013 studies we reviewed state forms when deriving the number of states with a reporting requirement for a particular element. As a result, the numbers presented below represent best efforts to determine if a state had a reporting requirement regardless of the rule language itself.

In 2009, 21 oil and gas agencies required the submission of well treatment reports within a time frame that typically ranged from 30 to 60 days. These reports were required under a variety of circumstances including initial well completions, re-completions, and in some cases for treatments alone. While requirements varied with respect to the amount of information listed, 16 states required a list of the materials used, 17 specified the volumes used, and 20 required reporting of the treatment depths (intervals). Ten states required a listing of chemicals and 9 of pressures used, but none required a listing of either the volume of fluid that flows back to the surface or an estimation of the volume of fluid that remains in the formation following the treatment. Figure 14 shows a select group of elements reviewed.

As of 2013, the number of states with a well treatment reporting requirement remained unchanged at 21. The number of states requiring the reporting of specific chemicals used in the well treatment process expanded from 9 to 21, a 133% increase. Additionally, based on a review of both regulations and agency forms, the number of states requiring reporting of pressures, depths, and perforation intervals was 11, 22, and 19, respectively. As of July 1, 2014, 16 states either required or allowed operators to report hydraulic fracturing chemicals to the FracFocus Chemical Disclosure Registry. Ten additional states were also considering using the FracFocus system for chemical reporting.

In 2013, the areas reviewed relative to well treatment were expanded dramatically. The new areas and number of states with a requirement are shown in Table 3.

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

FIGURE 14

Formation Treatment, Stimulation or Fracturing: Reporting

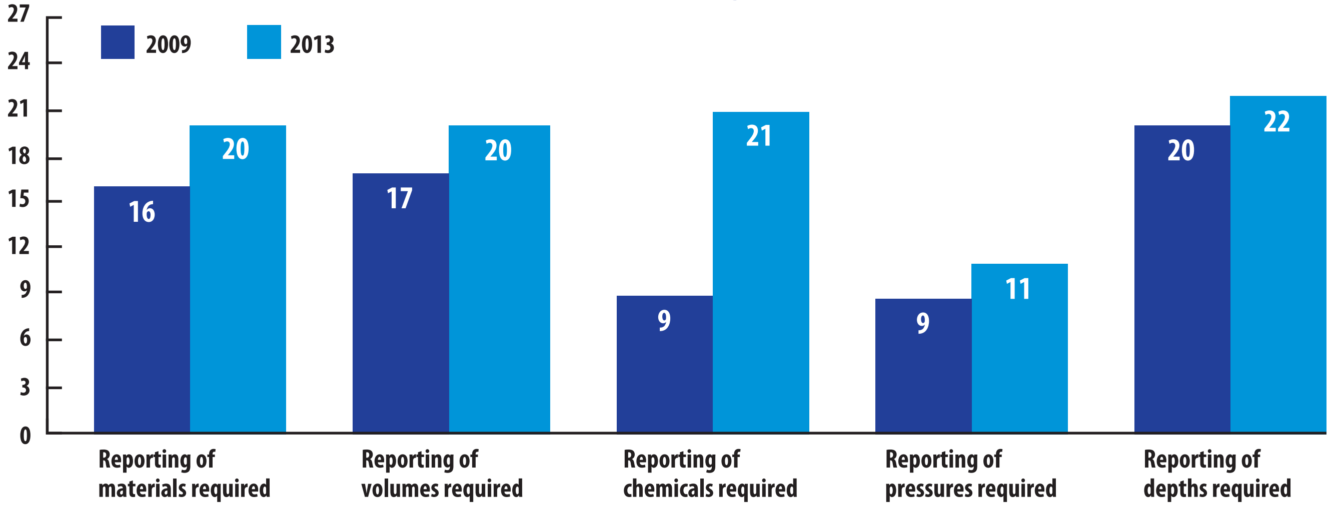


Table 3

Required by Rule	# of states
Specific materials/ chemicals such as diesel fuel prohibited	4
Agency requires prior submission of specific information about constituents	12
Inspector witnessing required	2
Pressure limitations specified	7
Minimum depth required	2
Adjacent water well testing and monitoring required	5
Wellbore mechanical integrity test before commencement required	7
Monitoring and recording of stimulation operations throughout the process required	8
Suspension of operation required upon evidence of mechanical integrity breach or failure	9
Surface equipment mechanical integrity test before commencement of fracturing required	2
Confinement of fracturing fluid to target reservoir required	4
Cement evaluation logs required under specific conditions	14
Wellbore schematic including hole size and casing size for each string required	17
Volumes of water used for hydraulic fracturing reported by category (e.g. recycled, fresh)	10

2013 Regulatory Proposals

The most prominent trend in 2013 is that states are increasing the direct regulation of hydraulic fracturing activity. In the past, well stimulation generally was not explicitly regulated; instead, states sought to ensure environmental protection largely through a focus on well construction. Proposed hydraulic fracturing regulations focus on regulator notification to allow witnessing of completions; prohibitions on chemical use; disclosure requirements for base water and chemicals used; mechanical integrity testing prior to treatment; and operational monitoring, especially of pressures, during treatment. Eight states had proposed rules on these issues as of late 2013. Of these issues, chemical disclosure has the most widespread regulatory activity, with six states currently conducting rulemakings. In fact, chemical disclosure has been one of the popular subjects for rulemakings in recent years, and nearly every major oil and gas state has addressed or is addressing this issue.

Well Integrity

Well integrity, from the perspective of water protection, 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 the 2013 Society of Petroleum Engineers 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.[29] 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 and present a threat to protected groundwater.

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 American Petroleum Institute (API) in Spec. 5CT. It specified 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 often 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. The API in Spec. 10A[30] 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 the 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. 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.

While nearly all states required the circulation of cement on surface casing in 2009, it was not a universal requirement. In some states, cement was required across the deepest groundwater zone but not all groundwater zones. Regardless, such variations from the circulation of cement on surface casing were still designed to ensure that groundwater zones were isolated from production zones.

Once the surface casing is set and the cement has had time to cure, the wellbore is drilled down to the next

29 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).

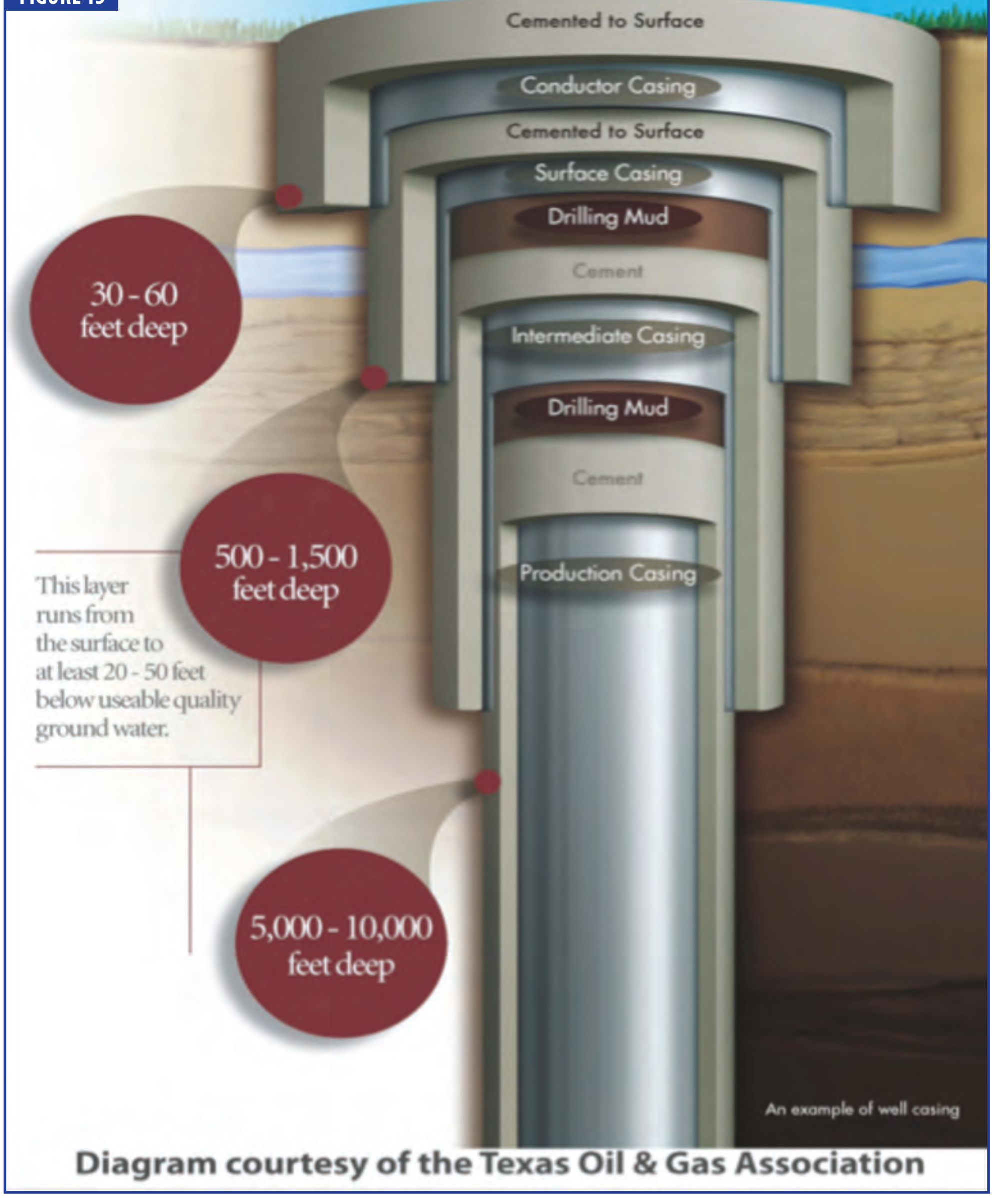
30 API also publishes a number of reference documents referred to as "Recommended Practices." With respect to casing and cementing, API has developed a recommended practice called RP-65.

zone where the intermediate or production casing will be set. In some states, 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.

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. In some cases, 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 cross-sectional diagram of a well equipped with casing and cement is shown in Figure 15. Although some states require complete circulation of cement from the bottom to the top of the production casing, most states 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

FIGURE 15



Source Texas Oil & Gas Association

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 provides a means to evaluate the ongoing mechanical integrity of a well through annular pressure monitoring.

Some states 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 good 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.
- **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 states, 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 states, such as Alaska, Michigan, and Ohio, may require an additional verification method using geophysical logs such as Cement Bond Logs (CBL) and/ or 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 can be evaluated. (See Appendices 5 and 6 for examples of CBL/VDL logs showing good cement bond and no cement bond/free pipe). 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."[31]

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.
- **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 detectable gamma ray. Count rates are measured to determine the velocity, flow rate, and distance of water from the tool.[32]

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.

2009-2013 Comparisons[33]

Between 2009 and 2013, a number of states amended well integrity standards, particularly those states where shale development is prevalent. For the most part, well construction requirements in place in 2009 remain consistent with those in 2013. However, several states (e.g., Ohio, Texas, Pennsylvania, Arkansas, Wyoming, North Dakota, West Virginia, and Colorado) have updated rules, and, the number of states requiring cement evaluation logs or other approved methods under specifically defined circumstances has risen from 9 to 14, a 64% increase.

In 2009, 25 states required surface casing to be set through the deepest protected groundwater zone, and 26 also required cementing of the surface casing from bottom to top. Additionally, 24 states required the setting of production casing to the top of or through producing zones with amounts of cement that range from bottom to top circulation to cementation at a defined height above each producing zone; and 20 states required a

31 American Petroleum Institute, *Isolating Potential Flow Zones During Well Construction,* HF 65-2, (Dec. 2010)

32 *Oilfield Glossary,* Schlumberger, http://www.glossary.oilfield.slb.com/.

33 In the 2009 study this area was called well construction.

cement setup/waiting period as part of the cementation process.

In 2013, most states required two or more strings of casing with varying amounts of cement for setting, and 25 states required that surface casing be set below the deepest protected groundwater zone. In one state, production casing cemented from the bottom to inside a cemented surface casing string or to surface can be used instead of surface casing set below the deepest protected groundwater zone. In all 27 states, surface casing must be set with a sufficient volume of cement to circulate from the bottom to the top of the hole. Although most states do not require a specific pressure test of the casing after it is set, 20 states require the cement be allowed to set for a specified period of time and reach a particular compressive strength before drilling below the surface casing shoe can be resumed, contributing to the competence of the cement job and, by extension, the isolation and protection of groundwater. In 2009, five states had a requirement in an element entitled "inspection/witnessing of well casing and cementing specified." For the 2013 study, this element was modified to read "operator required to notify an inspector prior to installing casing and/ or commencing cementing operations," and 11 states had a notification requirement. Although the 2009 and 2013 areas cannot be compared directly, it appears there is a trend towards more frequent witnessing of casing and cementing by state inspection staff. Figures 16 and 17 show a select group of elements reviewed.

FIGURE 16

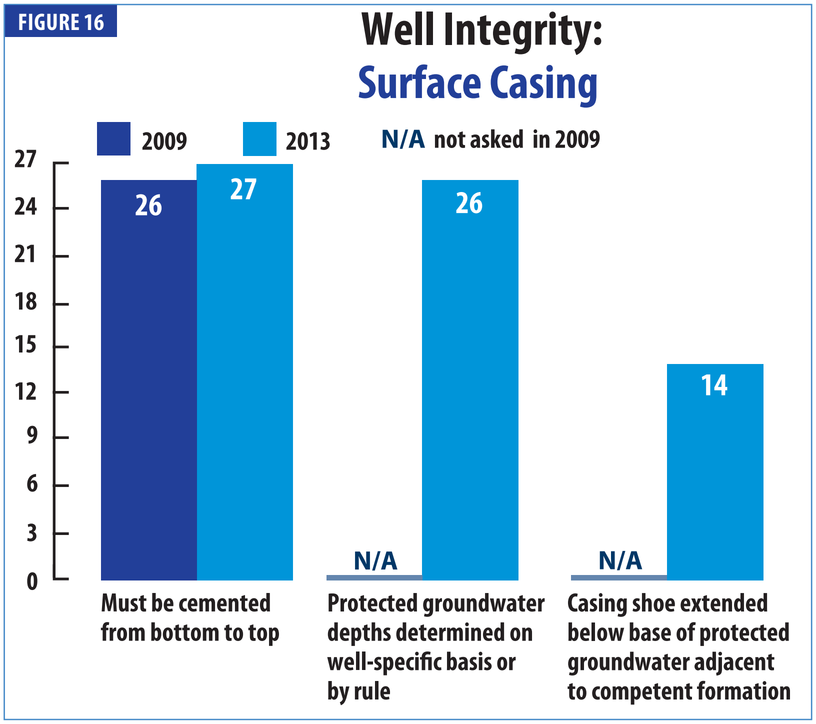
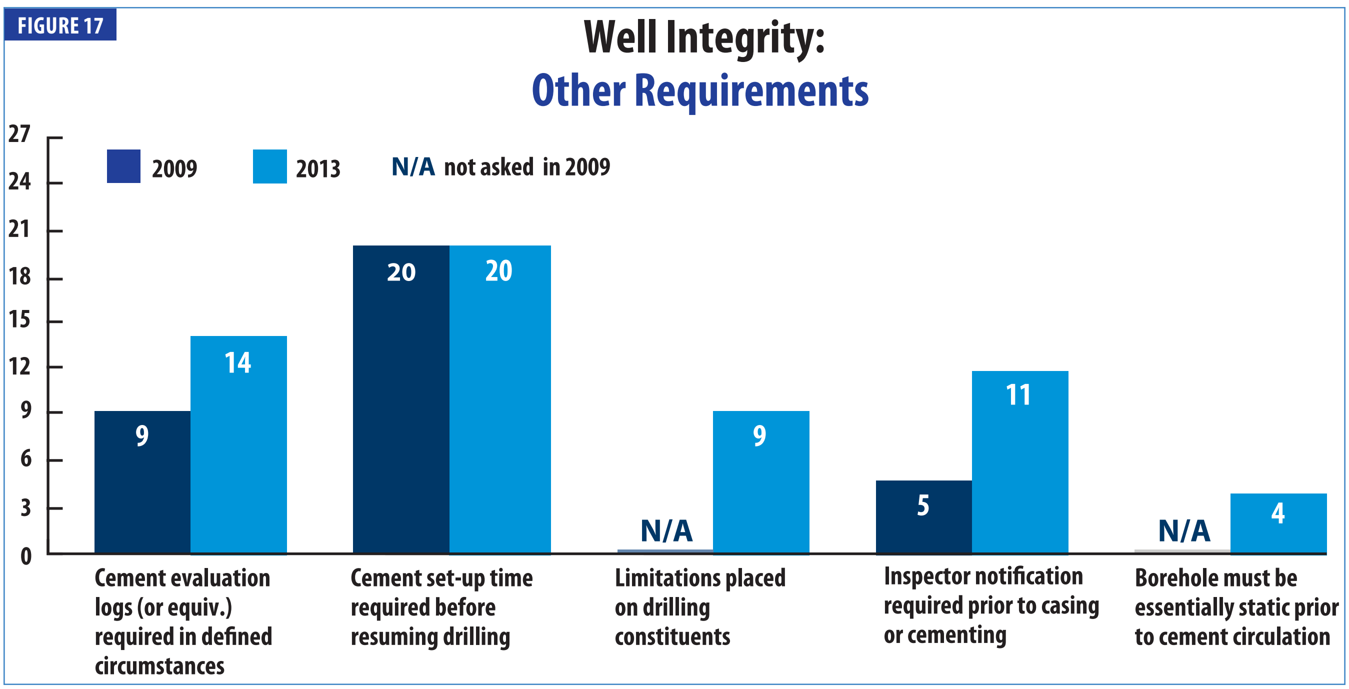


FIGURE 17

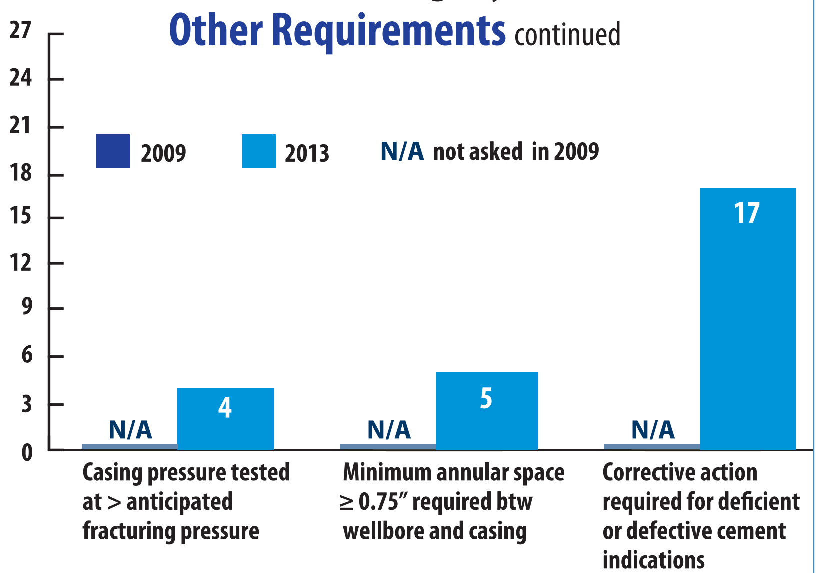


One of the new elements in the area of Well Integrity for 2013 was borehole conditioning. Two states had a specific requirement for mud removal, circulation establishment, or static borehole conditions prior to cementing of casing. Five states had a minimum annulus spacing requirement, in the absence of an exception, of 0.75 inches between some casing strings and the borehole or an outer casing string. In the new element of "corrective action required if there are circulation problems or other indicators of deficient, defective cement," 17 states had rule requirements to address such issues. Figure 18 shows a select group of elements reviewed.

2013 Regulatory Proposals

While late 2013 was a quieter period for formal rulemakings on well integrity, many states have suggested they will continue to improve their well integrity rules in 2014 and beyond. Recent trends suggest that states will focus on ensuring that casing and cementing is sufficiently robust and properly tested for conditions faced during stimulation and production, and on isolation of sections of the subsurface containing protected water, flow zones, and corrosive zones capable of over pressurizing the annulus. Three states had pending rulemakings that would require corrective action if a deficiency is encountered during cementing — often in the form of the failure of cement to circulate, indicating the presence of a subsurface void or permeable thief zone. Corrective action helps ensure that performance objectives are met before drilling or well completion activities are allowed to resume.

FIGURE 18 **Well Integrity: Other Requirements** continued



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. This practice is common in many states. The primary purposes of allowing temporary abandonment are to prevent plugging wells that may have future economic value and to avoid drilling replacement wells.

TA Implementation

In most states operators are required to notify the regulatory agency in advance of temporarily abandoning a well. In some cases the state agency may require an operator to either demonstrate that the well has mechanical integrity or that is it constructed and maintained in a manner that will prevent it from posing a risk to protected groundwater resources. Requirements can involve well testing, construction reporting, fluid level measuring, or other demonstration methods. Initial TA periods range from as little as one year to as many as five years. Most states allow an operator to renew TA status. Only a few states place an absolute limit on the renewal period for TA, but several provide that the operator must attest to the future value of the well. Although TA is a tool used to prevent the unnecessary plugging of wells with future value, unfortunately it has also been used as a means of avoiding abandonment costs associated with plugging wells. States are aware of this and are using tools such as a certification of future value for wells to prevent misuse of the TA process and avoid the addition of more wells to their orphan well inventories.

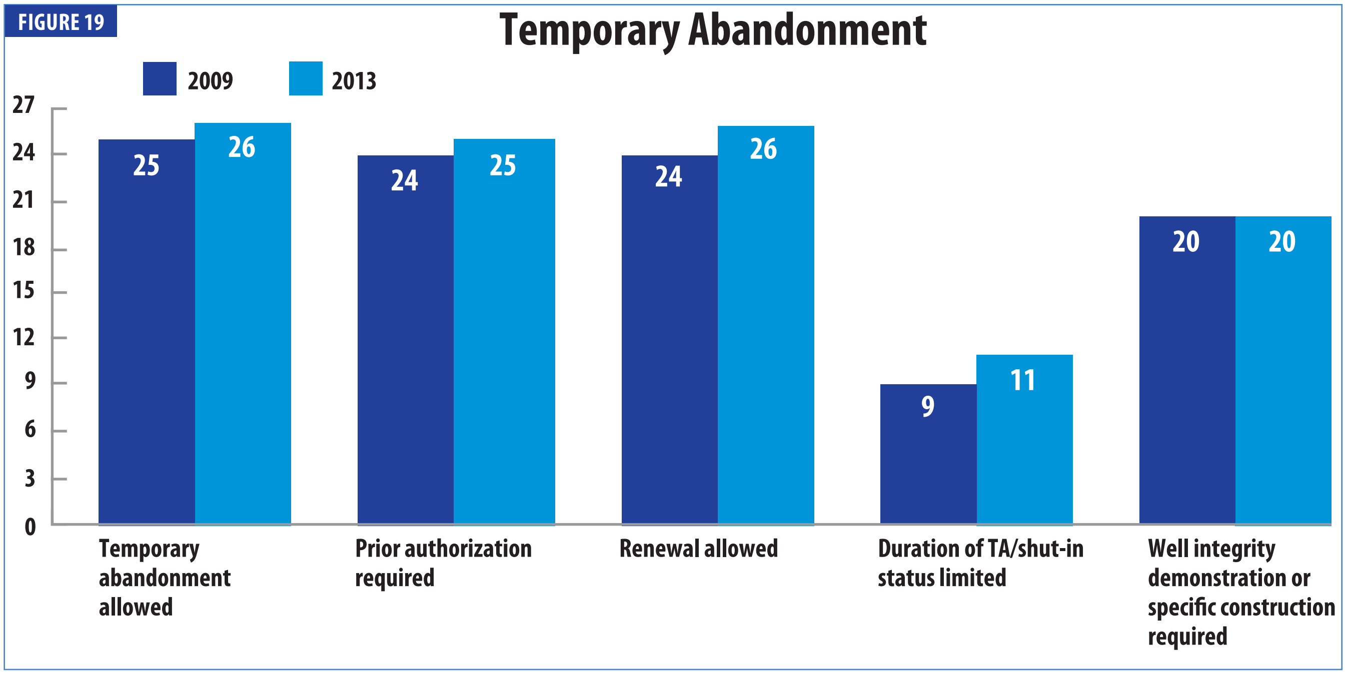
2009-2013 Comparisons

In 2009, 25 states allowed the practice of temporary abandonment and, of these, 24 required both a prior authorization for and renewal of TA status. By 2013, one additional state required prior authorization for TA status and two additional states had established a limitation on the duration of TA status. Figure 19 shows a select group of elements reviewed.

2013 Regulatory Proposals

Continuing a trend, two more states are seeking to limit the duration of TA status.

FIGURE 19



Well Plugging

The purpose of well plugging is to permanently seal the inside of the well and wellbore so that fluid cannot migrate from deeper to shallower zones or create reservoir problems through downward drainage. The process involves the placement of cement and other materials such as gels inside the well or wellbore in a manner that prevents the upward or downward migration of formation fluids. In 2013, all 27 states regulated the practice of well plugging to varying degrees. In most states, very specific requirements on the materials and placement methods for plugs are used, while in a few states the requirements are more general in nature. In 21 states, operators must submit a plugging plan in advance. In 26 states, a prior notice to the regulatory agency is required before a well can be plugged. This notice provides the agency with an opportunity to have field personnel witness the plugging to assure use of proper plugging materials and placement methods.

Materials

Wells are plugged using a variety of materials such as cement, bridge plugs, clay, gel, and other spacer materials such as drilling mud and water. Since the purpose of well plugging is to seal the wellbore, the competence, placement, and verification of plugs are critical. Each type of plug has unique characteristics. For example, when properly mixed and placed, standard Class A (Portland) cement provides a strong, relatively impermeable plug. Conversely, while bentonite (clay) plugs are more ductile and tend to seal off minor leakage pathways better than cement, when in contact with water, they do not swell in the presence of petroleum. Consequently, in most cases states will typically allow clay to be used as a spacer between cement plugs, but not as a primary plugging material. Cast iron bridge plugs (CIBP) provide a good well seal, especially when there is significant bottom hole pressure. CIBPs are also nearly impermeable, but they are subject to corrosion over time and need to be capped with an appropriate cement plug to assure the long-term integrity of the plugged well.

When properly mixed and placed, standard Class A (Portland) cement provides a strong, relatively impermeable plug

Intervals and Methods

Most states require a combination of plugs at multiple vertical intervals to assure long-term protection from fluid migration and to compensate for various downhole geologic and hydrogeologic conditions that might render the plugging materials ineffective. Most states require the placement of a cement bottom plug through and/or above producing formations and the placement of a top plug across the deepest groundwater zone. Additionally, 20 states require the pulling or cementing in place of uncemented casing to assure cement is

FIGURE 20

Well Plugging

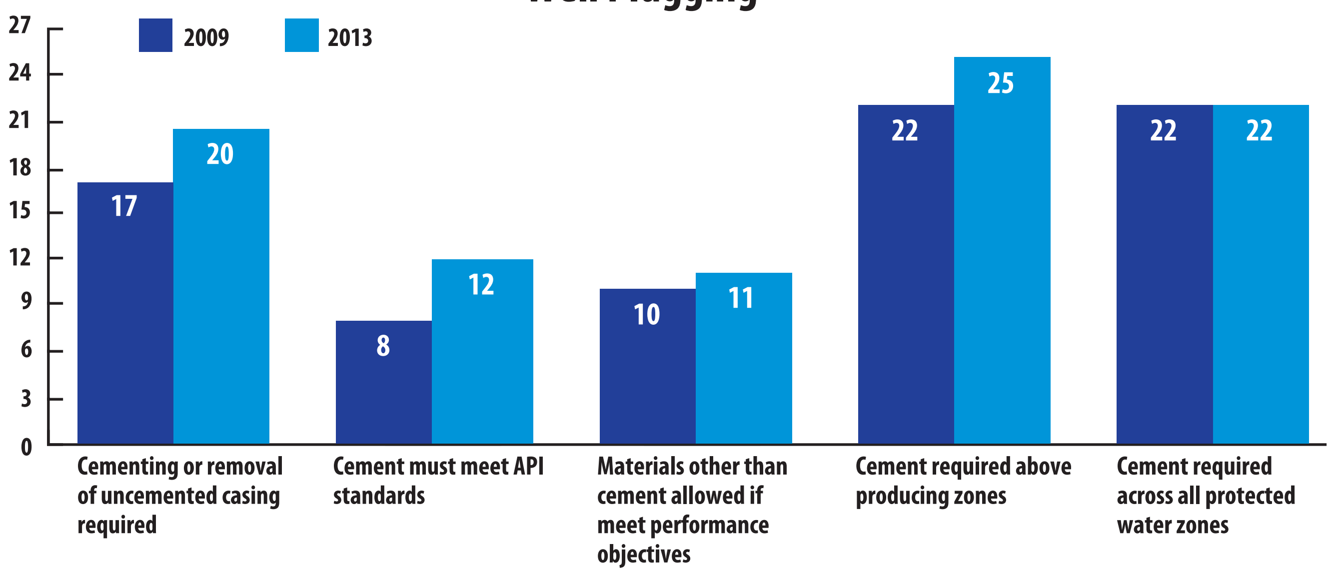
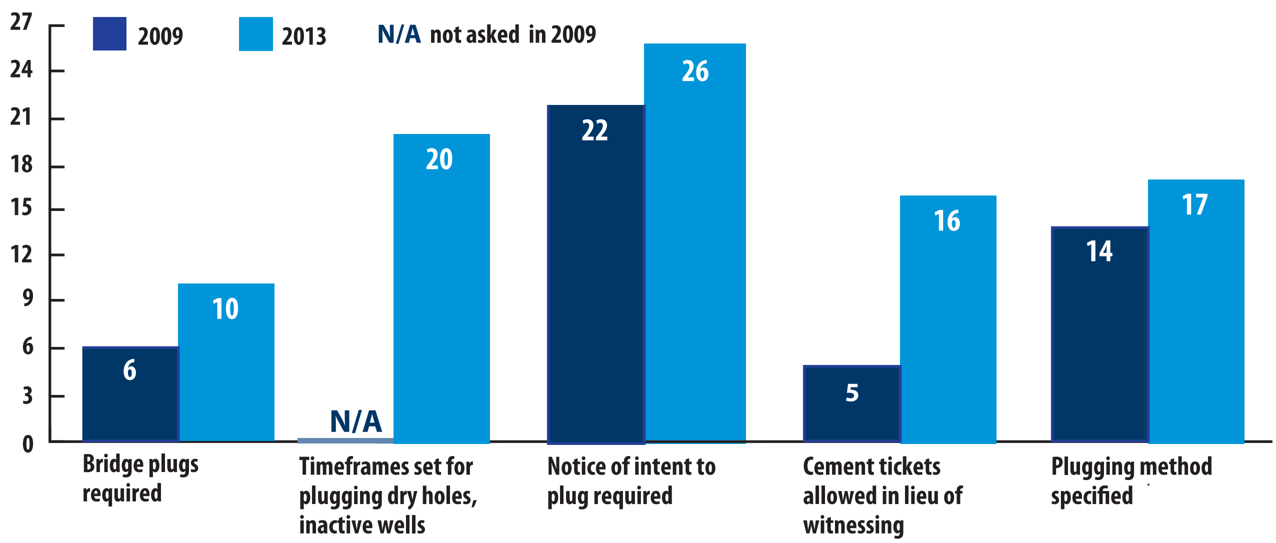


FIGURE 21

Well Plugging continued



in contact with either the wellbore or cemented casing. The majority of states also require that cement plugs be placed using a specific method such as the pump and plug (displacement) method or via dump bailing. Both methods are designed to spot plugs over particular intervals and to assure the plug fills the space for which it was intended. The use of surface down pumping (bull heading) of cement plugs, which can lead to channeling of cement under certain conditions, though not specifically prohibited in most states, is excluded by a requirement to place plugs using displacement or dump bailer methods. When used in conjunction with bridge plugs, the placement of cement plugs by displacement and dump bailer methods allows the regulatory agency to ascertain the location of plugs.

Reporting

Plugging reports detail the materials and methods used to plug the well including the plugging intervals, volumes, and types of plugs used, and the amounts of casing pulled or cemented in place.

Plugging reports are usually completed by the operator or operator's agent and must be submitted within a certain time following the conclusion of plugging. In some states, a separate affidavit of plugging is required if a plug job is not witnessed by agency personnel. Under such circumstances, the state may often require the submission of "cement tickets" from the company that supplied the cement so the volumes used can be independently verified.

2009-2013 Comparisons

In 2009, 17 states required the removal or in-place cementation of uncemented casing. By 2013, this number had risen to 20 states. With respect to cement placement above producing zones, the number of states with a requirement has risen from 22 to 25. In 2009, 14 states specified the method of plugging (pump and plug, dump bailing, or bullhead plugging). By 2013, three additional states specified the plugging method and these three required the pump and plug method. In the sub-element of plugging reporting, 26 states had required a plugging report in 2009; by 2013, all 27 required a plugging report. In 2009, 17 states required a report of the placement of bridge plugs. By 2013, this number was 24. Further, in 2009, 20 states required reporting of the amount of casing left in a hole after plugging. By 2013, this number had risen to 25. For 2013, a new sub-element was added to track the number of states with a specific timeframe for plugging reporting; 26 states placed a limit on the amount of time allowed to file a plugging report. Figures 20 and 21 show a select group of elements reviewed.

Storage in Pits

While the risk of groundwater contamination from downhole activities is expected to continue to decline as a result of more comprehensive well integrity requirements and better monitoring, reporting and inspection procedures, the risk of contamination of surface and shallow groundwater from surface waste management processes remains higher than subsurface risk. With the advent of horizontal drilling and multi-staged hydraulic fracturing, the volumes of water being managed have increased substantially. Many states are responding to this challenge by setting standards for pits and impoundments that include siting restrictions, liner requirements, and leak detection methods. Although steel tanks and other above ground containment systems are becoming more prevalent, excavated pits are still the most common means of storing fluids during drilling and well operations. See Appendix 15 for a detailed comparison of risk management considerations for pits and tanks.

Types and Purposes of Pits

Today, pits are used for storage of produced water, for emergency overflow, temporary storage of oil, burn-off of waste oil, and temporary storage of well completion and treatment fluids. The three most common types of pits are drilling pits, emergency pits, and produced water storage pits.

- Drilling pits are used to store the fluids used during the drilling process. These fluids are usually made up of fresh water and bentonite clay. However, in some locations, oil-based and saltwater-based muds are still used due to specific drilling and formation conditions. Pit liners are normally not used in cases where drilling mud is primarily fresh water, but are usually required for other types of drilling fluid.
- Emergency pits are constructed to capture spills and leaks. They are usually required to be kept dry except during an emergency and are not usually lined.
- Produced water storage pits are the largest type of pit and are used to store water that comes to the surface as part of the oil and gas production process. They are often associated with a Class II UIC disposal or enhanced recovery well.

Pit Siting and Construction

Many states limit the siting of pits based on such criteria as:

- **Distance to surface water:** In some states, pits may not be located within a floodplain or within the boundaries of the 100-year flood contour. In California, for example, pits may not be placed in areas considered "natural drainage channels." In other states, pits that are built within a floodplain must be constructed so that flooding will not result in water entering or leaving the pit. Many states require a minimum distance between surface water and the location of a pit.
- **Distance to groundwater:** While some states specify how far the base of a pit must be above groundwater, others prohibit the excavation of pits into or through the depth of the seasonal water table. Still others have no restrictions regarding the siting of pits with respect to groundwater.

Pits should be designed, constructed, maintained and operated in a manner that protects groundwater. Depending on the nature of fluids being placed in the pit, the duration of the storage, and the soil conditions, pit lining may be necessary to prevent infiltration of fluids into the subsurface. In 23 states, pits of a certain type or in a particular location must have a natural or artificial liner designed to prevent the downward movement of pit fluids into the subsurface. For example, in Louisiana, liners are required for produced water, onshore terminals, and washout pits. In some states, liners are also required for emergency pits on a case-by-case basis. Typically, pit liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment. For liners to work properly they must be seamed in accordance with the manufacturer's instructions. In some states, pits are also required to have leak detection systems, which are designed to provide the operator with the means of determining the continued integrity of the liner. Further, 20 states require fluids in pits remain a certain level below the top of the pit wall. This distance, referred to as the "freeboard," provides for a safety margin to prevent pit overflows in the event of significant rainfall.

Pit Operation

Routine inspections by the regulatory agency may include periodic placement of a pit's contents into tanks by the operator so examination by the agency and maintenance by the operator can be performed. This process is critical to assure that a pit will not pose a threat to either surface or groundwater. In 10 states, pits must be inspected by a state field inspector before they may be put into operation. The operation of a pit requires the operator to maintain the integrity of the pit, monitor for leaks, maintain fluid levels below established freeboard minimums, and prevent the introduction of materials that would render the contents of the pit non-exempt under the RCRA Subtitle C provisions. Although states do not typically require routine sampling and analysis of pit contents, oil and gas agencies typically hold the operator responsible if improper or illegal dumping of non-exempt waste into the pit occurs.

Pit Closure

After a pit has fulfilled its function and is no longer needed or authorized, it must be closed in a manner that will prevent pit contents and other materials from contaminating the soil or water. In drilling pits where fresh water and clay were used, closure is often accomplished by simply removing and properly disposing of the free fluids in the pit and burying of the pit residual solids within the pit. Where other types of drilling fluids were used, the fluids must be removed and properly disposed of, and remaining residual solids must be removed from the pit and either bio-remediated on-site or removed from the site and interred in an appropriate facility such as a special waste landfill. For example, Colorado Rule 905.b. (2), pit evacuation, states that prior to backfilling and reclamation, E&P waste must be treated or disposed. For pits with artificial liners, the typical procedure is to drain the pit and remove the liner, or drain the pit, shred the liner, and bury it within the pit boundaries. In either case, the removed fluids must be disposed of properly. In some states, the operator must file a pit closure report detailing the steps taken to close the pit and dispose of the contents.

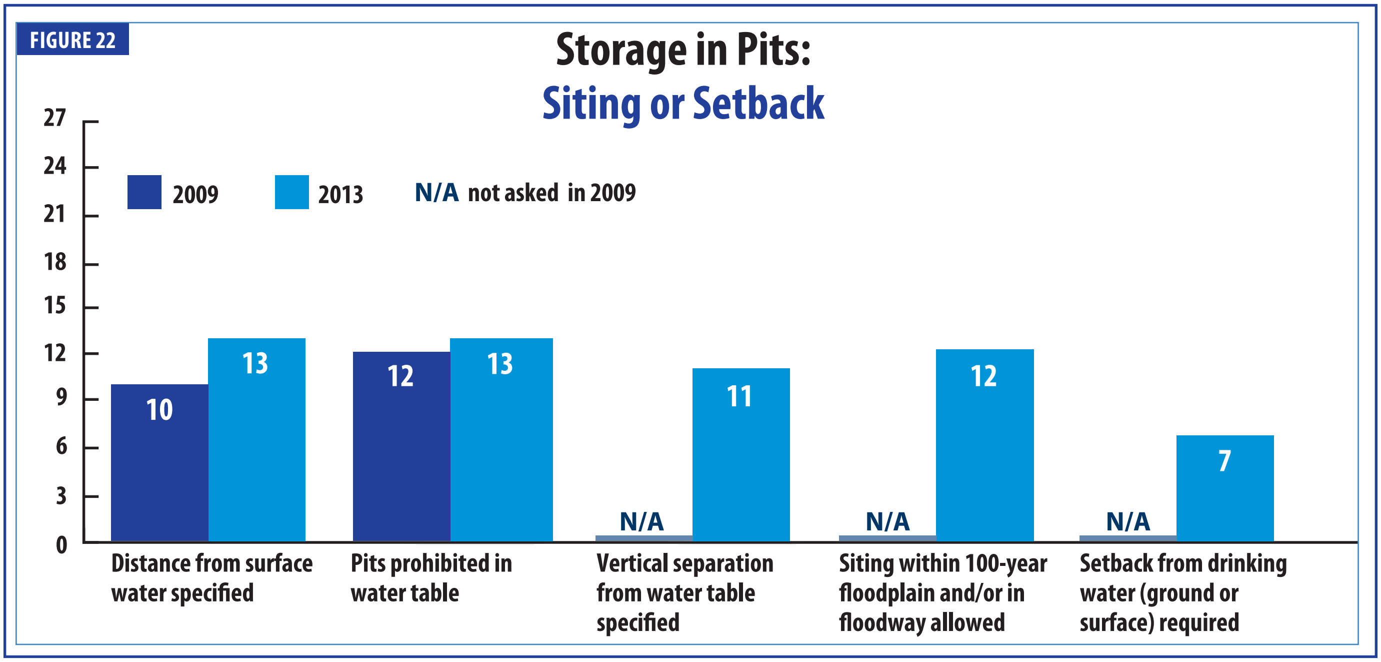
The operation of a pit requires the operator to maintain the integrity of the pit, monitor for leaks, maintain fluid levels below established freeboard minimums, and prevent the introduction of materials that would render the contents of the pit non-exempt under the RCRA Subtitle C provisions.

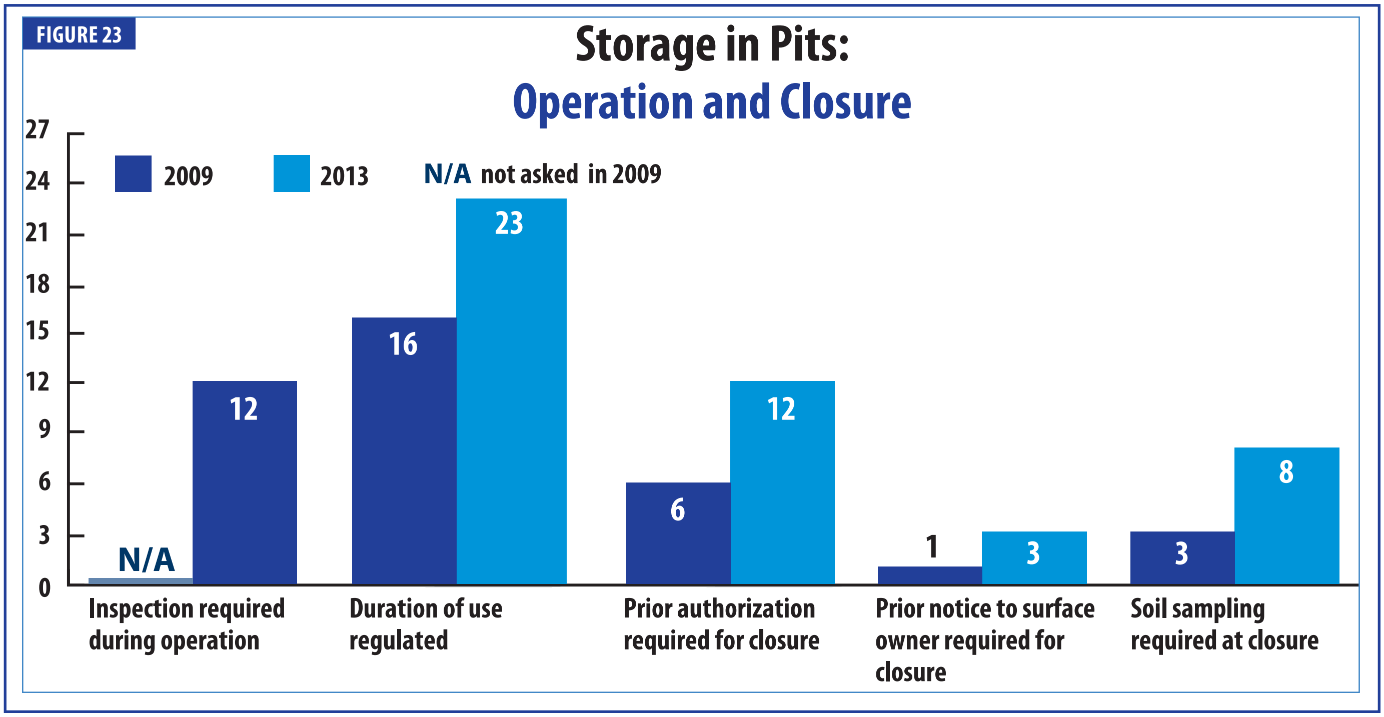
2009-2013 Comparisons

In 2009, all 27 study states had requirements governing the use of drilling or workover pits. In 15 of these states a competency standard for pit liners was required and 16 also required a maximum fluid level relative to the top of the pit wall (freeboard). By 2013, the number of states with a competency standard had risen to 22, and the number of states with the freeboard requirement was 20. In 2009, 16 states specified the duration of use for a pit. By 2013, this number was 23. With respect to pit closure requirements, six states required prior authorization to close a pit in 2009 and 12 had a similar requirement in 2013. In 2009, only three states required soil sampling following pit closure. By 2013 this number had risen to eight. It should be noted that due to the multitude of pit types, the standards specified above are not typically applied to all pits. Figures 22 and 23 show a select group of elements reviewed.

2013 Regulatory Proposals

A significant trend in proposed rulemaking on pits in the latter half of 2013 was the regulation of duration of





use. Four states addressed this issue. As pits grow larger and are used in increasing number and for novel purposes, the duration of their use is a ripe topic for regulatory oversight.

Storage in Tanks

Tanks can be portable, such as the steel tanks used to capture drilling fluids and store water prior to hydraulic fracturing or those used as test tanks at a wellsite, or more permanent, such as the steel, fiberglass, and polyethylene tanks used to store produced water and oil prior to pick up for sale or disposal. Tanks used for the storage of oil and produced water vary in material composition, placement configuration, and size depending on specific production needs. A group of tanks used to store oil and produced water is often referred to as a "tank battery." Where water is not co-produced with oil, the tank battery typically consists of one or more oil storage tanks similar to the photo shown above. However, when saltwater is part of the production fluid stream, the tank battery also usually includes a vertical gravity oil/water separator, sometimes called a "gun barrel" and one or more water tanks for the

Tank battery in northwest Oklahoma City
Source, GWPC

storage of saltwater that has been separated from the produced oil/ water stream. In some cases, additional tanks such as heater treaters, which use heat to break down the oil/water emulsion, are also present.

For this report, tanks are defined as enclosed units fabricated off-site. Unlike pits, tanks provide a closed system for fluid storage. See Appendix 15 for a detailed comparison of risk management considerations for pits and tanks. Modular tanks assembled on-site are most-often open-top and have design and operational components in some respects similar to pits and in some respects similar to tanks. Modular tanks are discussed in more detail in *Key Message 2: Emerging Issues*.

Tank Siting and Construction

Most states do not specify the materials to be used in the construction of tanks. However, five states have tank construction requirements based on the specific fluids being stored, and one state, Colorado, requires operators to use tanks that meet Underwriters Laboratories (UL) or American Petroleum Institute (API) standards, as applicable. In most states, the lack of a specific requirement such as an industry or technical standard allows for the use of a multitude of materials such as plastic, wood, concrete, steel, and fiberglass. While some materials are appropriate for the storage of particular types of fluids, others are not. For example, in some states, it is not uncommon for produced water to be stored in uncoated steel tanks. Since produced water is corrosive to varying degrees, storage in unlined steel tanks can lead to leaks and tank failures over time. In some cases, the use of cathodic protection is necessary to prevent metal oxidation with resultant degradation. Development of tank construction standards is evolving and more states are beginning to review their current standards with an eye toward implementing more specific requirements. For example, Alabama and Florida require operators to follow "generally accepted industry practices and standards," and Michigan requires pre-construction plans to be submitted to the oil and gas agency.

In part, because tanks may be more likely than pits to fail in a catastrophic manner and release their total contents in a single event, the use of secondary containment designed to hold the contents of entire tanks, or interconnected tank systems, is commonplace. In 22 states, tank batteries must be surrounded by a secondary containment structure or dike. These containment structures are often referred to in regulations as firewalls, but their principal purpose is to contain fluids from tank failures or leaks. Further, 21 of the states requiring a containment structure also specified their capacity. These capacities often ranged from one and a half (examples: Illinois and Indiana) to two (example: Florida) times the capacity of the tank or tanks surrounded by the structure.

Secondary containment structure-
Source,

Tank Operation and Maintenance for Initial Handling of Produced Fluids

Operation of tank battery systems has remained essentially unchanged for more than 150 years. Most of the work of moving fluids from one tank to another, and for separation of oil and water, is managed by gravity. The oil/water emulsion is placed into a separator, which is a vertical or horizontal tank designed to divide oil, water, and gas from a column of produced fluids. After separation, the oil and water are stored in separate collection tanks. Today, these tanks are typically made of steel or fiberglass, although older tanks may have been made of concrete or even wood. Management of fluid flow through the tank system is complex and involves many simultaneous processes that must remain in balance for the system to work properly.

A properly constructed and maintained tank battery can last decades. It is important that it is maintained over the life of the system so that leaks, spills and tank failures do not occur. As of 2013, 14 states required routine tank maintenance.

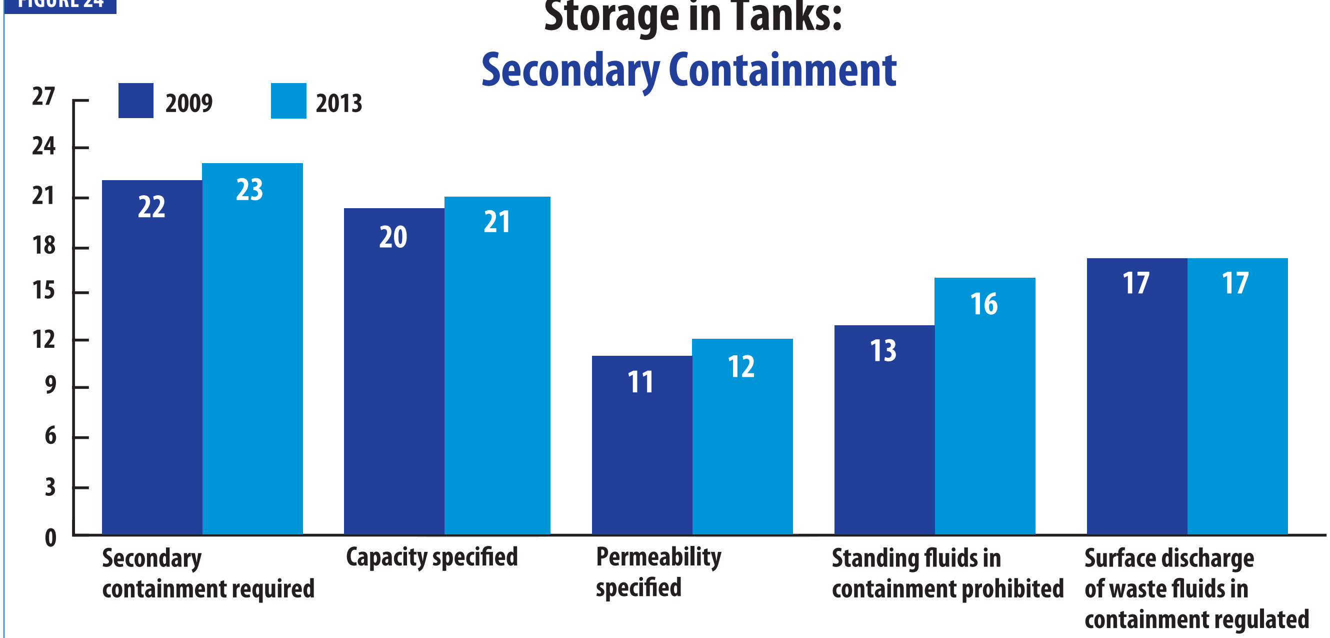
Tank Removal

After a tank has reached the end of its useful life, it must be removed from the site so that it does not pose an environmental or safety hazard. Steel tanks are most often re-used or cut up and sold for scrap while fiberglass tanks are re-used or cut up and disposed of in landfills. Removal of the tanks often leaves behind some contaminated soil at the tank battery site. If this soil is highly contaminated, it may have to be removed and disposed of properly, usually by interment in either a sanitary or special waste landfill depending on the level and nature of the contamination. In some cases, the soil is capable of being remediated on-site using procedures similar to those used for oil and saltwater spills. This may include either natural attenuation or active bio-remediation using disking of the soils and the addition of nutrients, lime and fresh water. The remediation methods allowed and the final remediation level required are determined by each state regulatory agency. In several study states, including Alabama, Alaska, Arkansas, and Kansas, tank battery sites must be remediated or the materials disposed of in accordance with specific requirements.

2009-2013 Comparisons

In 2009, five states required a prior authorization to construct a tank battery and five specified the types of materials to be used in tank construction. Between 2009 and 2013, no states added prior authorization requirements, while two additional states specified types of materials. Secondary containment was required by 22 states in 2009 and 23 states in 2013; of these, 20 specified the capacity of the secondary containment in 2009, 21 in 2013; 11 specified some type of permeability standard in 2009, 12 in 2013; 16 required ongoing maintenance in both 2009 and 2013; 13 prohibited standing fluids inside the containment area in 2009, 16 in 2013, and 17 regulated the discharge of fluids from the inside of a containment area in both 2009 and 2013. For this 2013 report, GWPC included a new element in the area of storage in pits, regarding tank removal and site restoration requirements. For 2013, eight states required site restoration to prior use, two required soil sampling, and five required a post closure report be filed with the oil and gas agency. Figure 24 shows a select group of elements reviewed.

FIGURE 24



Produced Water

Produced water is the water that comes to the surface as part of the oil and natural gas producing process; in this report, it includes both natural formation water and the flowback water from hydraulic fracturing. Produced water is typically more saline than fresh water with total dissolved solids (TDS) contents ranging from less than 1,000 parts per million (ppm) TDS (some coalbed methane zones) to over 200,000 ppm TDS (deep oil and gas zones). For comparison purposes, seawater contains about 35,000 ppm TDS. In addition to TDS, produced water may contain other constituents including organic compounds, metals, salts, various cations and anions, and naturally occurring radioactive material (NORM). While not covered in the original 2009 report, the subject of produced water and its transportation, use, storage, and disposal was added to the regulatory review in 2013.

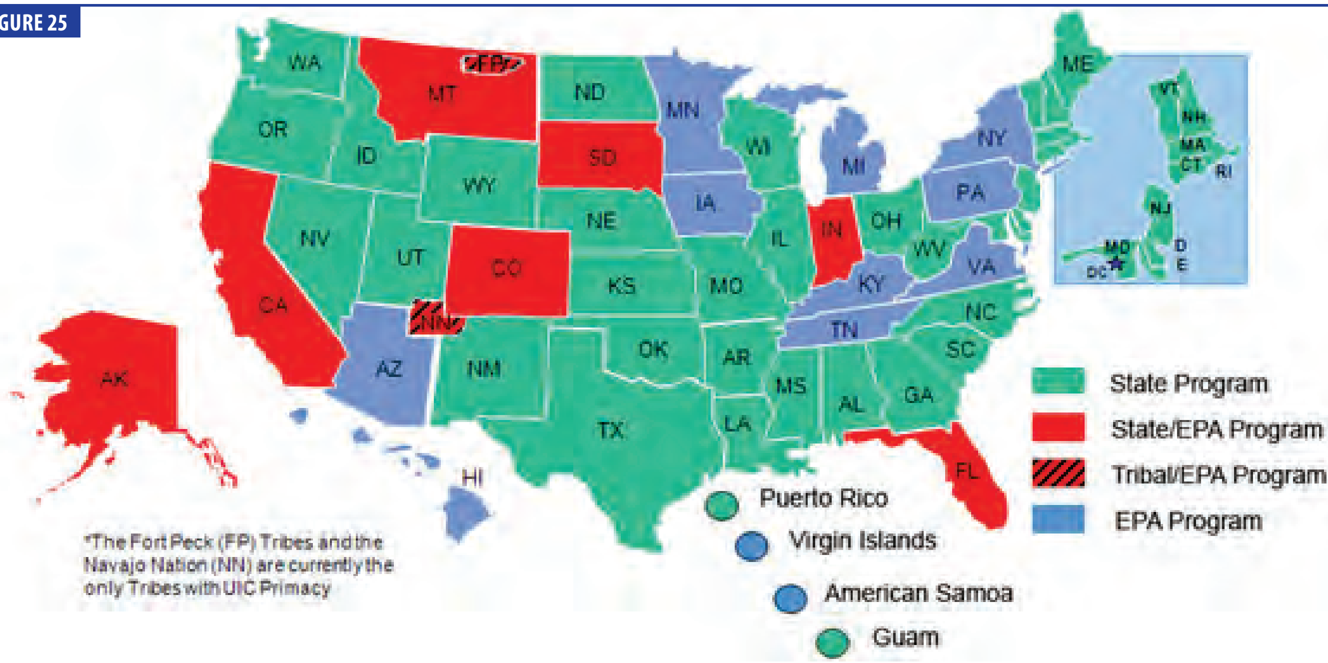
Transportation

Produced water is transported by truck unless a nearby disposal or enhanced recovery project is available to accept the water. As more options for managing produced water become available, other transportation options are being implemented, including transport via pipeline (either permanently installed or temporary laid on the ground surface). With recycling and reuse of produced water becoming more common, produced water is increasingly transported off-lease to either a storage facility to await further processing (which would entail additional transport) or to a treatment facility. From a treatment facility, the treated produced water would be transported again to a storage facility to await further handling or to a location where the fluid is reused in subsequent well completions. In all these instances, transportation can be accomplished via truck, pipeline (permanent and/or temporary), or even via rail or watercourse.

Injection for Disposal and Enhanced Recovery

The vast majority of produced water is re-injected underground through an injection well permitted under the Underground Injection Control (UIC) program. Although the UIC program is not reviewed in this report,[34] given its importance to disposal of produced water, a brief discussion is included here. In 1974, Congress passed the Safe Drinking Water Act (SDWA) which required the U.S. EPA to develop minimum federal requirements for injection practices. EPA established a number of injection well classes including Class II injection wells, which are designed to accept oil and gas RCRA Subtitle C exempt waste, including produced water. Regulations adopted pursuant to the SDWA are administered either by EPA or state and tribal partners

FIGURE 25



Status of state UIC primacy for all well classes

Source, USEPA

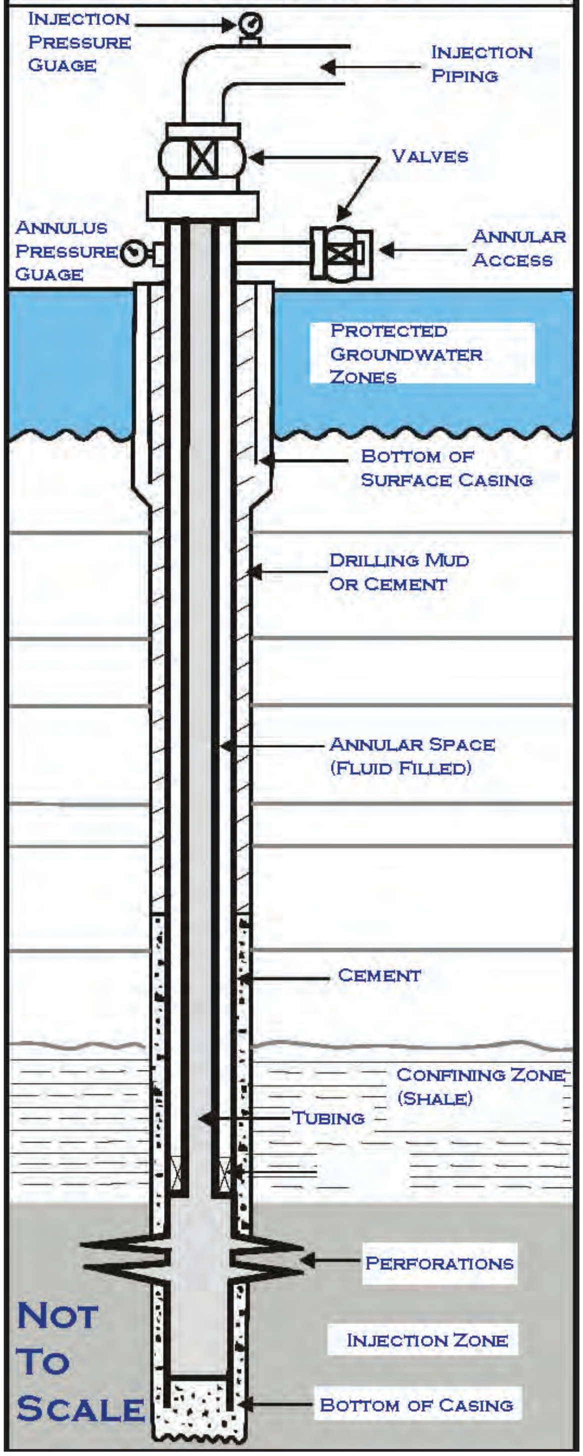
34 For a thorough discussion of the UIC program, see Ground Water Protection Council, *Injection Wells: An Introduction to Their Use, Operation & Regulation* (Sept. 2013).

subject to Primacy Agreements. Primacy states have adopted regulations that have been approved by EPA as protective of USDWs for Class II injection well operations. EPA administers the regulatory program in Direct Implementation states. To date EPA has delegated primary enforcement authority to state oil and gas agencies in 22 of the 27 study states with Class II Injection programs. (Figure 25) Class II injection wells must be constructed, tested, maintained and periodically reviewed to ensure that their operation cannot harm or threaten to harm a USDW.[35]

The goal of the UIC program is the effective isolation of injected fluids from USDWs. As oil and natural gas are brought to the surface, they generally mix with saltwater that is referred to as "produced water." On a national average, approximately 7-10 barrels of saltwater are produced with every barrel of crude oil.[36] Based on 2012 oil production figures alone for the U.S. of about 2.7 billion barrels of produced oil, this ratio of oil to produced water translates from 19 to 27 billion barrels of produced water generated during 2012 in the United States. This represents over 52 million bbl./day.[37]

Injection wells have been used in oil field related activities since the 1930s, over 40 years before passage of the SDWA. According to EPA, today approximately 168,000 Class II injection wells are located in 31 states. Class II wells used to inject produced water are categorized into two subclasses: produced water disposal wells and enhanced oil recovery (EOR) wells. At EOR projects, injection wells are used to increase production and prolong the life of oil-producing fields. Secondary recovery is an EOR process where produced water that was co-produced with oil and gas is re-injected into the oil-producing formation to drive oil into adjacent pumping wells, resulting in the recovery of additional oil. Tertiary recovery is an EOR process that is used after secondary recovery methods become inefficient or uneconomical. Tertiary recovery methods include the injection of gasses such as carbon dioxide, water with special additives, or steam to maintain and extend oil production. These methods increase the amount of oil to be retrieved out of the subsurface.[38]

FIGURE 26 Typical Class II Injection Well



Source GWPC

35 Underground Injection Control Program, 40 C.F.R. pt. 144 (2013).

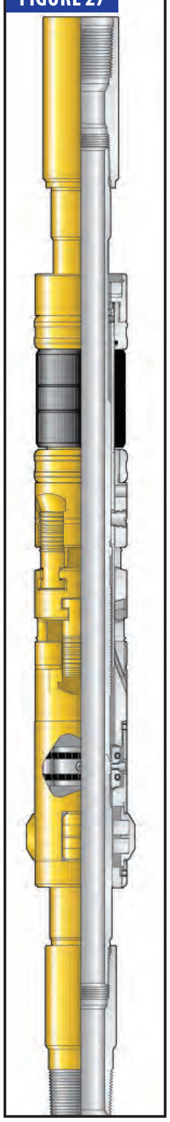
36 Katie Guerra, Katherine Dahm and Steve Dundorf, U.S. Department of the Interior, Bureau of Reclamation , *Oil and Gas Produced Water Management and Beneficial Use in the Western United States,* (Sept. 2011).

37 *U.S. Field Production of Crude Oil,* U.S. Energy Info. Admin., http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpus1&f=a (last updated Sept.. 27, 2013).

38 C.E. Clark & J.A. Veil, *Produced Water Volumes and Management Practices in the United States,* ANL/EVS/R-09/1 (2009) [hereinafter Clark & Veil 2009] (prepared by the Environmental Science Division, Argonne National Laboratory for the U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory).

Class II wells are subject to a permitting process that requires a technical review to assure adequate protection of drinking water and an administrative review defining operational guidelines. The evaluation of site suitability for a Class II disposal well is very similar to that for a Class I nonhazardous waste injection well. The site's subsurface conditions are evaluated to make sure an injection zone is present that can contain injected fluids and that this zone is overlain by sufficient confining zones to keep the fluids out of drinking water sources. Regulators establish injection pressure limits and specify procedures for conducting initial and routine mechanical integrity tests. The wells must be constructed to protect USDWs, and wells are tested and monitored periodically to ensure no drinking water is being negatively impacted by the operations.

FIGURE 27



Source, Baker Hughes, Inc.

As shown in Figure 26, Class II injection wells are designed to confine injected fluids to the authorized injection zone, preventing the migration of fluids into USDWs. Through the permitting process, site-specific requirements are imposed to address any unusual circumstances. These injection wells are drilled and constructed using the same techniques as those for Class I non-hazardous wells, with steel pipe (casing) cemented in place to prevent the migration of fluids into USDWs. Surface casing in conventionally constructed wells is cemented from below the lowermost USDW up to the surface to prevent fluid movement. Cement is also placed behind the injection casing at critical sections to confine injected fluids to the authorized zone of injection. A typical produced water injection well also has the injection tubing through which the fluids are pumped from the surface down into the receiving geologic formations. A packer similar to the one shown in Figure 27 is commonly used to isolate the injection zone from the space between the tubing and injection casing above the packer, called the casing-tubing annulus. In some cases, multiple wells will be constructed under one permit to manage the fluids in an entire oil or natural gas production field. The overall well system for injection is then evaluated by regulators to make sure all the components are properly constructed.

After Class II injection wells are placed in service, groundwater protection is assured by testing and monitoring the wells. Injection pressures and volumes are monitored and reported as a valuable indicator of well performance. Effective monitoring is important since it can identify problems below ground in the well, enabling quick corrective action to prevent endangerment of USDWs. Tests that evaluate the conditions of the various well components and the formations in the subsurface are required prior to initial injection and no less than once every five years afterward.[39] In some cases, more frequent testing may be required by regulatory authorities. All tests and test methods are rigorously reviewed by the state and/or EPA. Test data, as well as data on the volume and characteristics of the fluids injected into the well, are regularly evaluated by regulatory agencies to make sure USDWs are protected by the operation and maintenance of the wells.

Closure of Class II wells must be conducted in a manner protective of USDWs. Although regulations vary slightly from state to state, a cement plug is commonly required to be placed in the well across the injection zone, with additional plugs placed across the base of the lowermost USDW and near the surface.

Another potential option for disposal of produced water includes treatment at a permitted facility capable of removing the constituents of concern to levels that meet permitted discharge standards. This potentially includes transport to and treatment at POTWs[40] or CWTs. A facility that discharges treated water into waters of the United States must have a National Pollutant Discharge Elimination System (NPDES) permit. For a POTW to accept a waste stream for treatment, the facility must show that the accepted waste will not interfere with the treatment process or pass through the

39 Underground Injection Control Program, 40 C.F.R. pt. 144..

40 As previously noted above, as part of this study, GWPC surveyed the study states regarding the use of POTWs for discharging production fluids including flowback water. Of the states responding, three indicated this practice was banned by regulation, five states did not have a regulation covering this disposal method but would not allow it as a matter of policy, and nine indicated it was either regulated by another state agency or would otherwise be allowed under certain circumstances. As noted in the permitting findings, as of 2013, six state oil and gas agencies had permitting requirements for POTWs accepting this waste.

facility untreated.[41] Since POTWs are typically not designed to treat fluids with constituents found in produced water (e.g., high TDS concentrations, hydrocarbons, etc.), problems have occurred as a result of produced water being sent to POTWs including impacts to the treatment process or the discharge of constituents at levels detrimental to the receiving water body.

Properly designed CWTs are an option for treating produced water to levels allowing for reuse in subsequent well completions and even potentially for discharge to a surface water body. In the latter case, the NPDES permitting process is critical in determining appropriate discharge standards. Although a few CWTs have been issued a NPDES permit that allows for the option of discharge to a surface water body, it is currently not a common practice.

With the practice of recycling or reusing produced water, some form of treatment is likely needed. Environmental risks associated with this activity include the disposal of the produced water effluent stream when it is not fully utilized in other well completions and the disposal of waste streams generated as a result of the treatment process. These areas of increased environmental risks are further discussed in the *Key Message 2: Emerging Issues* section of this report.

Produced Water Recycling and Non-Injection Reuse

Over the past few years, fluid recycling and reuse has become more prevalent in the oil and gas industry. Not only does fluid recycling and reuse lower costs but it also lowers the amount of new water that must be obtained to conduct well drilling and completing operations, and decreases the overall amount of fluid requiring disposal. A primary factor in the increased use of fluid recycling has been the large volume of water that is typically necessary to conduct multi-staged hydraulic fracturing operations in horizontal wells. As the volumes of fluid needed to conduct fracturing operations dramatically increased and new shale gas plays were developed, the ability to acquire water of suitable quality to conduct these operations became more problematic. Water usage depends on many factors including the shale involved, lateral length, and fracture design. For example, water usage in the Marcellus in Pennsylvania has been recorded to range from 2 to 4 million gallons per fractured well, while water usage in the Eagle Ford can range from 3 to 16 million gallons.[42] Drought conditions in some regions of the country such as the southwest added to the difficulties of acquiring new water and made the use of recycling a viable alternative. In some cases, regulatory authorities such as the Susquehanna and Delaware River Basin Commissions became involved in the process of authorizing water use for hydraulic fracturing, creating a new regulatory hurdle and making fluid recycling even more attractive. In Pennsylvania, the lack of nearby Class II disposal wells for injecting flowback water and associated transportation costs to injection wells in neighboring states has incentivized development of recycling and reuse technology.

With the advent of fluid recycling, a whole new set of challenges is arising. Larger volumes of fluids have to be managed on-site, treatment systems have to be constructed and maintained, fluid treatment residuals and by-products have to be disposed of, and new piping and transport systems between the wells and the treatment facilities have to be built. In some states, such as Texas, new regulations have been developed to regulate and facilitate the practice of oilfield recycling.[43] These regulations address storage in pits, disposal methods, management of waste haulers, and the use of commercial versus non-commercial facilities for recycling. Other states, such as Ohio, have passed legislation requiring entities to have a permit before they can store, treat, process or recycle produced water, and authorizing the chief to adopt rules for the construction and operation of such facilities.

On-site treatment and reuse of fluids using smaller portable water treatment systems is also becoming popular in more rural areas. These systems work well for small volumes of fluids (dependent on the level of treatment required) and are usually fully self-contained so that treatment by-products are kept within the unit until their proper disposal can be accomplished.

The treatment and reuse of produced water is becoming more prevalent. It was not included in the 2009 report but now warrants in-depth review of current regulatory programs and is discussed further in the *Key Message 2: Emerging Issues* section of this report.

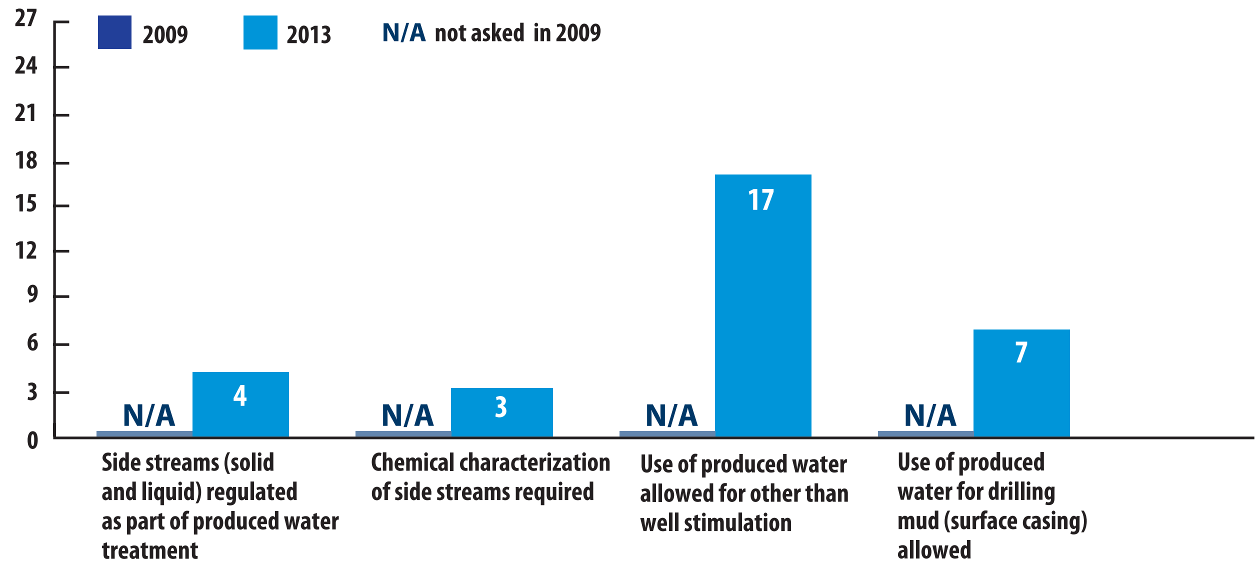
41 Objectives of General Pretreatment Regulations, 40 C.F.R. § 403.2 (2013).

42 Data gathered from well disclosure reports on FracFocus, http://fracfocus.org/.

43 *Texas Railroad Commission Rule 8; 16 Tex. Admin. Code § 3.8* (2013).

FIGURE 28

Produced Water Recycling and Reuse



2009-2013 Comparisons

The area of produced water recycling was not reviewed in 2009. Consequently, the only results available in this element are for 2013. Figure 28 shows a select group of elements reviewed.

2013 Regulatory Proposals

An emerging issue in 2013 was the characterization of side streams from produced water treatment, with two oil and gas states (North Dakota and Pennsylvania) addressing the topic. As more produced water is recycled and reused instead of being directly disposed in UIC wells, sometimes complex and varied waste side streams have developed. These side streams are the result of a variety of treatment methods, the number of which in use around the country increases by the month. While these side streams must ultimately be disposed by a legal method (which varies by state), it is difficult to determine which method may be appropriate where the contents of the side streams are unknown. Side stream characterization rules will help regulators make protective decisions when permitting recycling operations and side stream disposal.

Exempt Waste Disposal (Drill Cuttings and Tank Bottoms)

Wastes such as drill cuttings and tank bottoms typically require a different disposal strategy than produced water. While some wastes, such as drill cuttings, can be disposed of using underground injection, the primary disposal methods for such wastes may include onsite burial, off-site transport and burial in solid waste landfills, reuse for road base material or dust suppression, or bio-remediation using land-farming techniques. However, some wastes may contain metals and other constituents at concentrations that make their reuse or on-site remediation problematic. The determination as to whether a waste is RCRA Subtitle C exempt is based on several criteria. However, with respect to oil and gas wastes the most commonly used rule of thumb is if a waste is "intrinsically derived from primary field operations associated with the exploration, development or production of crude oil and natural gas" it is typically considered Subtitle C exempt. In most cases, such wastes retain their exempt status. However, where an exempt waste is mixed with a listed hazardous waste, the resulting mixture is no longer exempt, and becomes subject to the RCRA Subtitle C provisions. Additionally, where an exempt waste is mixed with another, non-exempt hazardous characteristic waste, and the resulting mixture exhibits hazardous characteristics, the mixture is no longer exempt and becomes subject to the RCRA Subtitle C provisions.[44]

44 EPA Office of Solid Waste: *Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*, EPA/ 530K-01-004.

Management of Wastes

Surface management and land application of wastes is regulated in 23 states, either through direct control by the oil and gas agency or another state environmental agency. For example, the Wyoming Oil and Gas Commission regulates the application of waste to land if the application occurs on a lease. However, off the lease, the same process is regulated by the Wyoming Department of Environmental Quality. Similarly, in North Dakota, small applications of waste on a lease are handled by the North Dakota Industrial Commission, whereas larger applications of waste, whether on or off a lease, come under the jurisdiction of the North Dakota Department of Health. Road spreading of some E&P wastes is one method of on-site management that is commonly allowed in multiple states. This technique is typically limited to the application of drilling wastes such as cuttings and tank bottoms, which are primarily sand but may contain up to 19% oil by volume.[45] One concern raised by the road application of waste is the potential contamination of

FIGURE 29

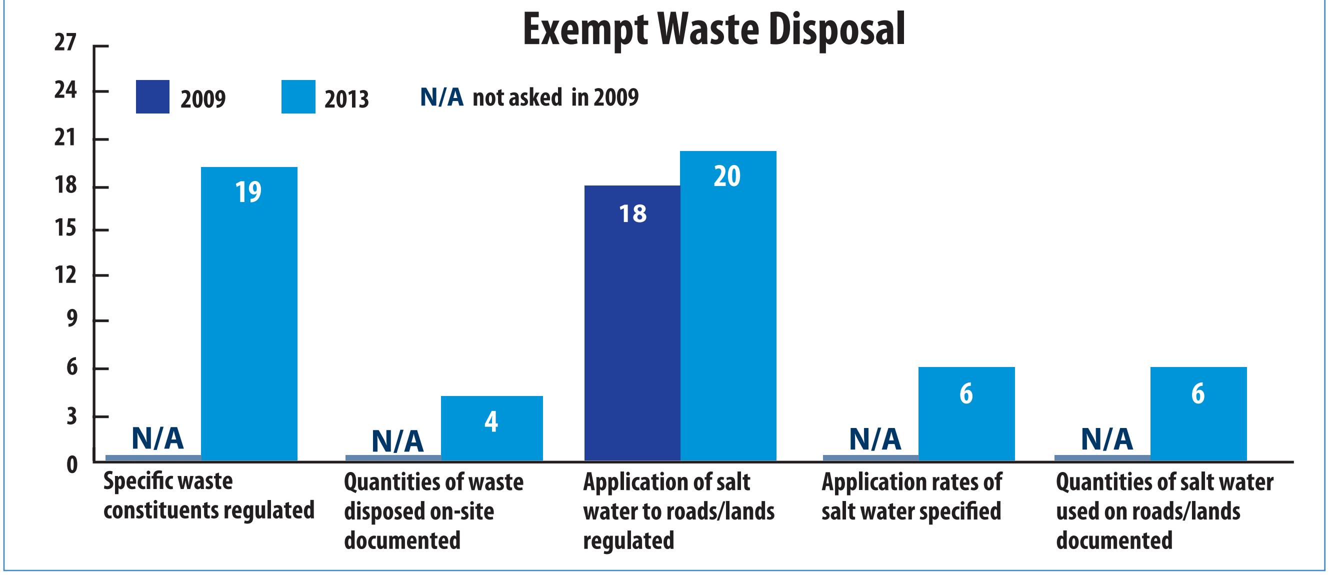
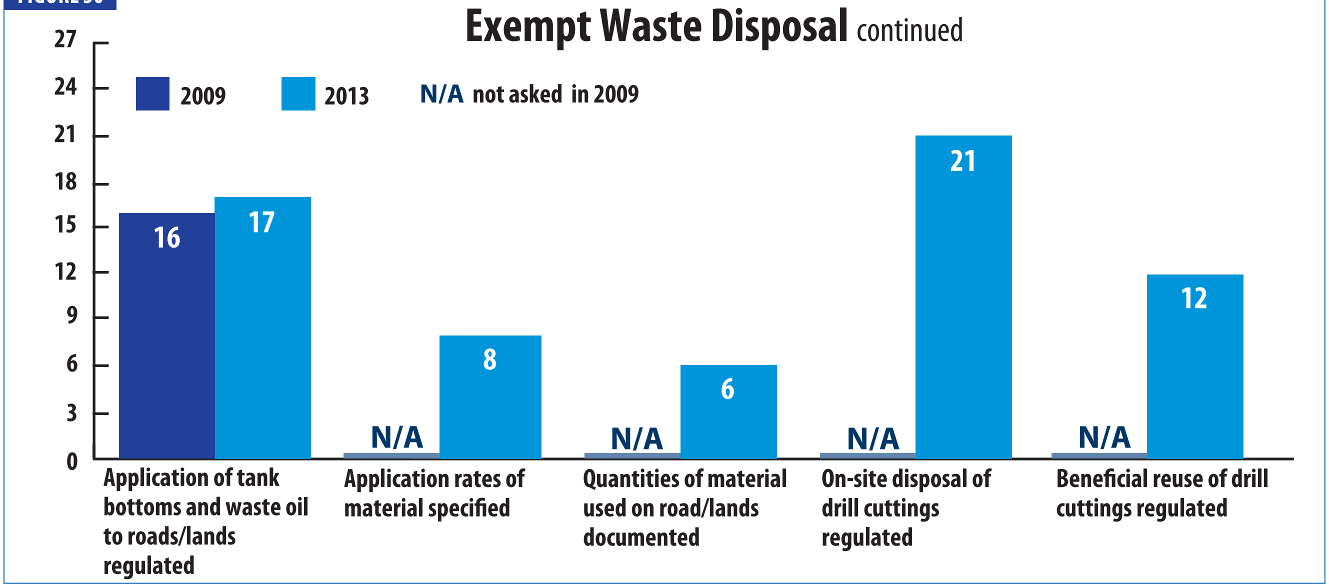


FIGURE 30



45 *EPA Office of Compliance Sector Notebook Project: Profile of the Oil and Gas Extraction Industry,* EPA/310-R-99-006 (Oct. 2000).

surface water sources due to dispersion of these wastes into roadside ditches. However, a 2000 EPA report covering Crude Oil Tank Bottoms and Oily Debris stated that "when conducted in accordance with state requirements, roadspreading can be considered a beneficial use of a material that would otherwise require disposal."[46] Further, another 2000 EPA report covering Completion and Workover Wastes reported that "no incidents were identified where roadspread completion/workover fluids or other completion/workover wastes were responsible for environmental damages."[47]

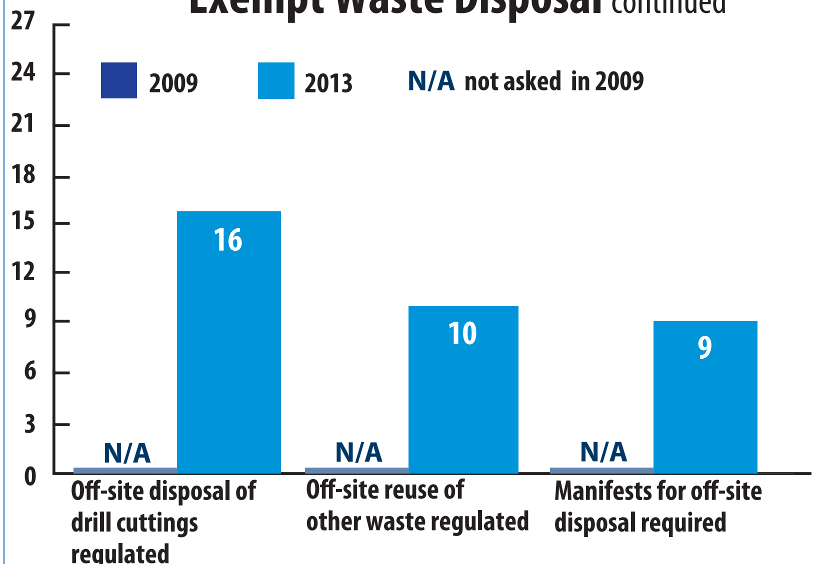
2009-2013 Comparisons

In 2009, 23 states regulated the on-site disposal of RCRA Subtitle C exempt waste such as drill cutting and tanks bottoms. Of these, 16 allowed tank bottoms and waste oil to be applied to roads or land. By 2013, this number had risen to 17. In addition, several new 'other waste' elements were reviewed in 2013, including:

- On-site disposal of drill cutting regulated (21 states)
- Beneficial re-use of drill cuttings regulated (12 states)
- Off-site reuse of other waste regulated (10 states)
- Manifests for the transportation of wastes off-site required (9 states)

FIGURE 31

Exempt Waste Disposal continued



Figures 29, 30, and 31 show a select group of elements reviewed.

Spill Response

Spills of oil and gas products and wastes on a lease can occur under a variety of circumstances, including leaks from flowlines, wellheads, tanks, and pits. Although many state oil and gas agencies require the reporting of E&P waste spills within a specified time period, this does not mean the oil and gas agency will retain jurisdiction over the management of the spill. In several states, jurisdiction over a spill depends on factors such as the location and volume of the spill and the affected environmental media. In at least four states, spills are managed under split jurisdiction. For example, in Illinois and Indiana, if an oil or produced water spill enters water, it falls under the jurisdiction of the state water quality or pollution control agency. In Indiana, spills of oil or saltwater in soils that do not reach a waters of the state are managed by the Indiana Department of Natural Resources (IDNR), Division of Oil and Gas, while spills that enter waters of the state fall under the jurisdiction of the Indiana Department of Environmental Management (IDEM). The jurisdictional nexus for a spill is spelled out in a Memorandum of Agreement between the IDNR and IDEM (Appendix 7).

Spill Reporting

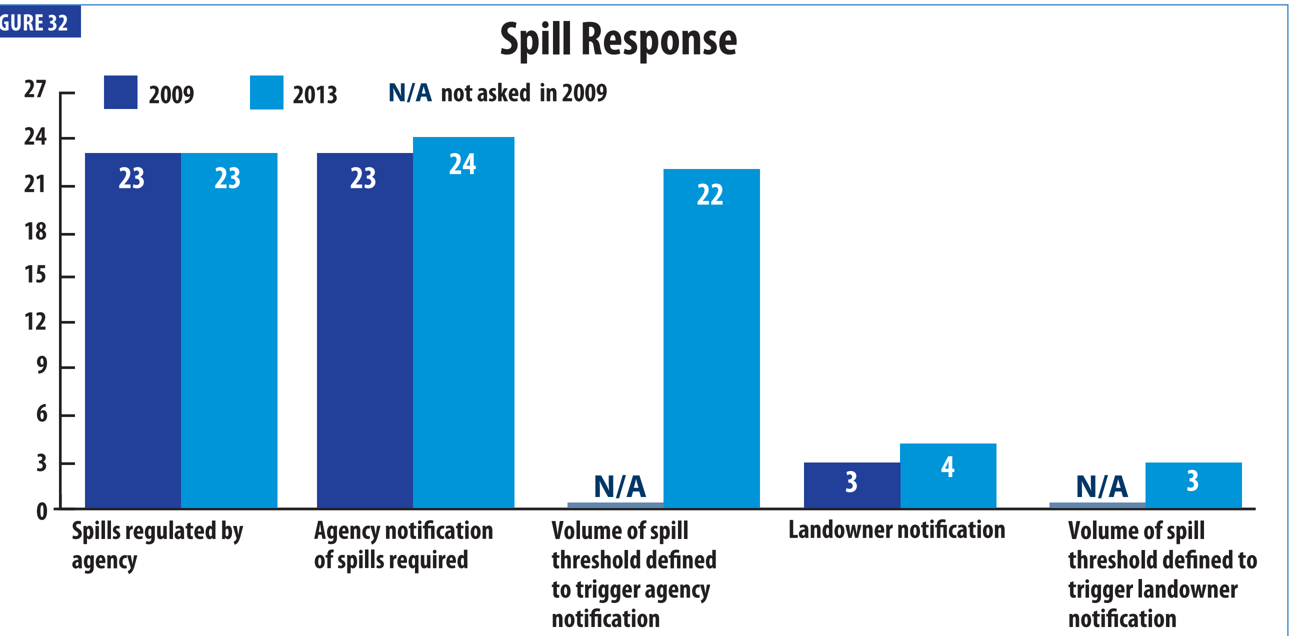
Requirements for reporting a spill of oil and gas products or wastes are often dependent on the nature, location, extent, and volume of a spill. In many cases, when a spill is contained within a secondary containment structure, does not leave the lease or enter surface water, or is small (<1-5 barrels), the reporting of spills is made only to the oil and gas regulatory agency. Otherwise, spill reports are typically made both to the oil and gas agency and to the state environmental regulatory agency. In most cases, both verbal and written notices are required with different timeframes for reporting. In a few cases, state regulations require an operator to also report the spill to the landowner.

46 EPA, Office of Solid Waste, *Associated Waste Report: Crude Oil Tank Bottoms and Oily Debris* (Jan. 2000).
47 EPA, Office of Solid Waste, *Associated Waste Report: Completion and Workover Wastes* (Jan. 2000).

Remediation/Disposal

In most cases, oil spills can be managed on-site using land-farming or bio-remediation techniques such as the mixing of oil with the soil, fertilization of the site, watering of the site, and periodic tilling and monitoring of remediation. In Indiana, the Division of Oil and Gas utilizes a formal Spill Management Guide as a manual to implement cleanup requirements. When an oil spill into soils renders the soil saturated to the point where bio-remediation would not be effective, the affected soils are typically managed by removal and disposal into a special waste landfill.

FIGURE 32



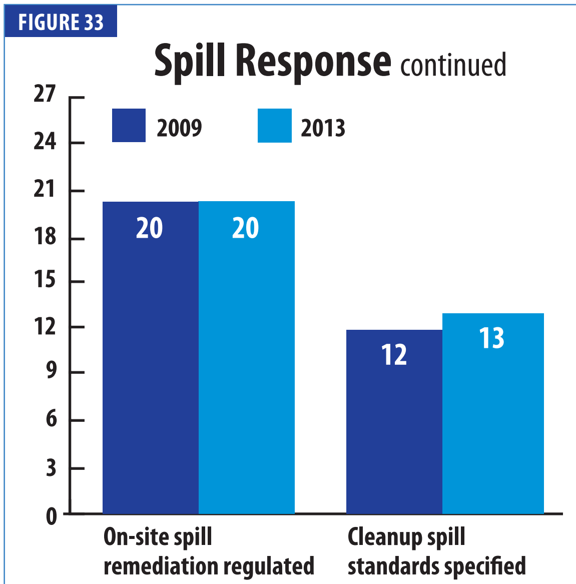
Spills of produced water tend to be more damaging to soils and vegetation than oil spills. Produced water has the capability of damaging the soil matrix resulting in soil compaction. Further, the salt content of produced water is typically sufficient to cause damage to sensitive vegetation such as food crops and trees. Additionally, the sodium absorption ratio (SAR) of soils impacted by produced water can be sufficiently high to prevent vegetative growth.[48] To deal with the issues of spilled produced water some states have guides for in-situ remediation of saline soils.

Regardless of agency jurisdiction over management of a spill, 13 states have specific cleanup standards related to spills.[49] For example, Colorado's regulations specify the cleanup standards for organics and inorganics in soil and groundwater, including allowable concentrations for total petroleum hydrocarbons, benzene, toluene, ethyl benzene and xylene, TDS, and various metals.

2009-2013 Comparisons

In 2009, 23 oil and gas agencies regulated spills of oil and produced water from oil and gas operations; 23 states also required the submission of a report of spills based

FIGURE 33



48 *See generally*, Kerry Sublette, *Remediation and Restoration of Hydrocarbon and Brine Contaminated Soils* (Oct. 2013).

49 In this case, the number is based on a review of state oil and gas rules and responses to GWPC's survey of state oil and gas agencies which specified cleanup standards for their agencies and for other state environmental agencies.

on the location, extent, and quantity; 20 states regulated on-site spill remediation; and 12 implemented specific cleanup standards. Except for the sub-elements of agency notification of spills required, and cleanup standards specified, these figures did not change for 2013. However, two new elements were added for 2013:

- Volume of spill threshold to trigger agency notification (22 states); and,
- Volume of spill threshold to trigger landowner notification of spills required (three states).

Figures 32 and 33 show a select group of elements reviewed.

2013 Regulatory Proposals

Five states had rulemakings concerning spill response in late 2013, making it a common topic of rulemaking during this period. With public scrutiny of oil and gas operations and especially accidents at an all-time high combined with the increased rate of production, rapid and effective spill response is a priority. The most common elements of Spill Response addressed in this round of rulemaking include timeliness of notification to regulator and surface owner, volume triggers, on-site remediation rules, and clean-up standards geared toward the substances spilled and the medium where the spill occurs.

State Programs

To gain a more complete understanding of regulatory functioning, this study profiled selected areas of state oil and gas regulatory programs, including program staffing, budgets, permitting, inspections, orphan sites programs, and witnessing of field processes, as well as supplementary documents that fall outside the traditional bounds of notice-and-comment regulation.

Regulatory Variability: Strength of State Programs

Critics of regulatory variability between states may assume that more regulation is always better and that differences between programs indicate flaws or inadequacies. Some studies cited the variability between state programs as de facto evidence that some programs are better or worse than others at protecting water resources. The fact that there are differences between state programs has also been used to call for national regulation of oil and gas activities like hydraulic fracturing. In fact, the variability between state programs is a natural outgrowth of the unique characteristics of each state. There is no such thing as "national" geology, geography, topography, or hydrology. State programs protect water resource best because they address the unique conditions that exist locally.

From the public viewpoint it may appear reasonable to conclude that all state programs should implement the same level of operational requirements and that they should be the most technologically advanced. This is not necessarily true. Implementing the exact same requirements regardless of circumstances could be beneficial in some situations but disastrous in others. For example, it might seem like a good idea to require that surface casing be set at a minimum distance below the deepest underground source of drinking water (USDW). While that might work in most cases, in some places over-pressured and contaminated zones are located below, but in close proximity to, the deepest USDW. In such a case, the mere drilling of the hole into the deeper zone could result in the contamination, rather than the protection, of USDWs. State regulatory programs understand the regional and local conditions that provide the basis for appropriate regulatory requirements. The professional staffs in these programs not only know the local geologic conditions, but in many cases were involved in crafting the regulations in a manner designed to provide the greatest protection for the environment given those conditions.

It may be time to dispense with the notion that a one-size-fits-all regulatory approach would somehow be better than the so-called "patchwork quilt" of regulations built by individual states. When it comes to regulations protecting groundwater, it is not a question of most -- it is a question of best. And the question of which regulations are best for a state is most effectively answered by each state's regulatory programs, given state regulators' understanding of the unique circumstances that exist within their states.

On the other end of the spectrum there are those who ask: "If state control is better because it is closer to the issue wouldn't a significant degree of local control be even better yet?" In limited situations, the answer to that question can sometimes be yes. For example, in Oklahoma and Texas local governments regulate some aspects of oil and gas activity. In most cases, however, local political subdivisions are not equipped to handle the rigors of an extensive oil and gas regulatory program. They often do not have the technical or field staff, funding, understanding of local geologic conditions, or petroleum engineering experience to properly or safely monitor oil and gas E&P. Traditionally, where local regulations exist, they have tended to complement the state regulatory programs or manage aspects of oil and gas that are not regulated by the state.

In almost all cases, the GWPC believes states are situated at the most effective level to regulate oil and gas E&P. State regulations are evolving through a process of continuous improvement acquired through greater knowledge of geology, engineering, and technology, and there is no reason to believe that overlaying additional federal controls on the regulatory process would lead to better, safer, or more environmentally protective development of oil and gas. However, it should be noted that research conducted by federal agencies can play a significant role in the development of state regulations and programs.

Role of Supplementary Documents in Regulation

A comprehensive understanding of a state's regulatory program requires looking at the use of supplemental documents. State agencies utilize a wide variety of guides, manuals, policies, and similar tools to complement and expand their regulatory programs. These documents provide guidance—often on a daily basis—for agency employees and industry entities alike, helping all parties apply broad regulations to more discrete events, circumstances, and permit conditions. While this section does not provide a comprehensive overview of the unique supplemental documents and tools at work in each state, it serves to acknowledge the existence of these additional materials and provide examples that illustrate their role in oil and gas regulation.

- **Field Rules.** These rules (sometimes called orders) are often specific to a particular oil and gas field, pool, zone, or other narrowed geologic location, supplementing more broadly applicable statutory and regulatory requirements. They allow regulatory agencies to incorporate geologic, engineering, and other types of unique data for a field into a more focused set of rules for operators in different regions of the state. These rules often relate to regulations that require local details and unique information such as well spacing, drilling, and completions operations or allowables. For example, North Dakota has a special field rule addressing proper spacing for the development of the Clarks Creek-Bakken Pool in McKenzie County, and California's Bellevue Field Rules require annular cement fill to the surface or at least 500 feet above the uppermost oil, gas, or anomalous pressure zones.
- **Guidance, Manuals, Instructions, and Handbooks.** These documents break down certain aspects of rules and regulations, most often related to requirements or conduct necessary for particular processes or operations. These supplements to a state's regulatory program assist entities in navigating certain aspects of their operations in a manner that satisfies all applicable regulations. In some instances, agencies will go through a public notice and comment period when they write or amend these documents. These materials address various aspects of field operations, and can provide an all-in-one resource for operators, bringing together relevant rules from various agencies in a state that regulate aspects of oil and gas operations. For example, Kentucky's principle secondary document is called an "Operator's Manual" and includes rules from multiple agencies, while Alaska publishes industry guidance bulletins that describe the conduct of specific operations, such as *Bulletin No.10-02A*, which applies only to mechanical integrity testing. New Mexico has an environmental handbook that contains the requirements for discharge plan approvals, groundwater contamination investigations, waste oil treating plants, below-grade tanks, and several other environmental topics. Pennsylvania publishes various technical guidance documents that provide additional information to operators beyond the language of the rules regarding spills, well integrity, wastewater permitting, and other similar topics.
- **Policies, Notices, and Orders.** Policies, notices, and orders can set forth the manner in which agencies expect operators to conduct their operations within the scope of the existing oil and gas rules. These documents may simply indicate how an agency intends to interpret and apply certain rules generally, or may bind specific parties directly. Often, these documents are used to address very specific or unique aspects of operations or to clarify certain rules that an agency has found to be particularly confusing or problematic. For example, Colorado has a policy specific to bradenhead

monitoring during hydraulic fracturing treatments in the Greater Wattenberg Area. Indiana published a policy letter memorandum on coal seam protection clarifying requirements for new wells that also included a FAQ section. Sometimes, notices will be published to bring operator's attention to revisions in certain requirements and how those revisions apply in specific situations. For example, Arkansas published a notice to operators regarding revised casing requirements for wells drilled in specific counties. In Kansas, precedential orders may bind immediate parties facing a special circumstance while also creating precedent for future similar situations, one example being a particular application to establish special field rules for horizontal wells in the Mississippi formation. Michigan's State Supervisor of Oil and Gas has the authority to issue "Supervisor of Wells Orders" which serve as direct notices regarding requirements applicable to a particular situation that requires special attention. *Supervisors Order #2-73*, for example, sets forth casing and sealing requirements for certain wells drilled with rotary tools.

- **Forms.** Forms are perhaps the most common supplementary documents used by state agencies to implement regulations. Although rules will sometimes specify the information that must be contained in a report to the agency, they will more often simply require that an operator report information about their activities on a form "prescribed by the agency." The forms used to submit reports are usually developed by the agency and include such reports as Well Completion or Recompletion, Sundry Notices, Notices of Intent, Well Stimulation, Well Plugging and various other reports used to provide well and site specific information to the agency. Even where a rule specifically states what has to be reported to an agency, the forms used to submit the report may expand upon the rule language and include information not specifically listed in the rule. In some cases the information about a particular activity may be contained on more than one form. For example Well Completion or Recompletion reports usually contain information about the depth of the well, the construction specifications, testing and some well stimulation activity such as materials used. In addition some Well Treatment reports may contain information about the pressures used in the treatment process, the specific chemicals that may have been used, the actual depths of each treatment interval and other information. As a result these forms must be reviewed in tandem to gain an overall understanding of a well treatment. Although forms are not rules, the information contained on the form is typically mandatory. Failure to provide the information listed on a required reporting form is a violation of state rules and usually may result in enforcement action regardless of whether a state rule lists the particular information required by the report.

- **Best Management Practices (BMPs).** These documents describe practices in the oilfield that are recommended as the best available means of conducting a particular activity. They do not typically have the force of law, but rather serve as recommendations only. Ohio has a best management practices document addressing oil and gas wellsite construction, while Oklahoma has a document entitled *Pollution Prevention at Exploration and Production Sites in Oklahoma—Best Management Practices for Prevention and Control of Erosion and Pollution.*

Staffing and Equipment

Oil and gas agencies are typically staffed by natural resource professionals including managers, geologists, engineers, administrators, and usually attorneys. In 16 of the 19 states responding to a GWPC survey, a geologist or engineer must review drilling permit applications. In some states, a college degree (Associates or Bachelors) or equivalent industry experience is required to qualify for a field inspector position. States provide specialized field equipment to inspectors for many purposes. For example, in 18 of the 19 states responding to the survey, field inspectors are equipped with laptop or equivalent electronic data capture equipment that allow them to see the inspection and enforcement history of a well or surface facility and to submit electronic inspection reports to a district or central office for review and follow-up. In 10 of the surveyed states, inspectors are also equipped with kits to perform field tests of water quality. Further, 18 surveyed states equip their field staff with GPS receivers that can be used to accurately locate a well, determine a tank battery or pit location and boundaries, and assist in the accurate identification of facilities. Finally, 10 of the surveyed states equip their field staff with Smartphones to aid in communication with district and central offices and with other inspectors. District and central office staff are typically equipped with personal computers and have access to vehicles to conduct field site visits and attend public meetings and hearings. In addition to internal staff, most oil and gas agencies have access to other state resources including technical and field staff of other state environmental agencies and legal services of the State Attorney General's Office. For example, in some states it is the responsibility of the Attorney General to provide legal services for the collection of penalties issued by the oil and gas agency. In other states, an environmental agency may provide field services such as sampling and analysis, specialized equipment such as electromagnetic meters to measure soil conductivity and identify underground saltwater plumes, and technical expertise from staff chemists, biologists, toxicologists and other technical staff.

Budgets

Based on figures from the 19 surveyed states, oil and gas agencies had a combined operating budget of $200,211,761 for 2012. The total active oil and gas related well count in the surveyed states was 1,043,873. This means that, nationwide, on a per well basis, states have less than $200 available for all agency functions, including but not limited to oversight and inspection of particular wells. From state to state, the dollars available per well range from as little as $41 in one rural state with relatively accessible shallow and single-zone completions and relatively low production to a high of $1,400 in a state with very remote well locations, deep and multiple production intervals, and relatively large amounts of production.

Inspections

Site inspections are one of the core functions of a regulatory program. In 2013, the 19 states that responded to a survey cumulatively conducted over 268,992 inspections. The total number of state inspectors in the surveyed states was 459. As with budget figures, however, the ranges of wells per inspector vary from state to state. The variation in numbers of wells per inspector from state to state may relate, in part, to differences in such factors as well densities, depths and types, inspection frequency, inspector duties, age of production, and types of inspections conducted (e.g., witnessing of well construction and plugging vs. routine inspections).

While the time it takes to conduct an inspection varies widely depending on the density and accessibility of wells, the criteria used to conduct inspections, and the experience of the inspector, many states have policies to inspect wells on a routine schedule. Any increase in the current frequency of well inspections would require additional staff. Therefore, it is critical for states to focus their existing inspection efforts where they will do the most good. Using indicators such as prior enforcement history; proximity to drinking water sources; sensitive ecosystems, and urban areas; well types and ages; and types of activities such as plugging and well construction, agencies can inspect those facilities which pose the greatest risk of harm to the environment and human health. Some states, like Nebraska, utilize the GIS function of their RBDMS program to overlay the areal extent of source water protection areas over a well location map. By using the proximity of oil and gas wells to source water protection areas, they can prioritize inspections so that wells in these areas receive increased attention.

Data Management

The importance of having and managing good regulatory data cannot be overstated. Information lies at the heart of effective regulatory implementation. The regulatory agencies' ability to collect, store, extract, analyze, and accurately present data is essential to the protection of water resources.

By sharing and validating data across agency jurisdictions, with regulatory field staff, regulated industries, and the public, decision-makers can accurately assess trends in energy production, water quality, and supply, and maintain the delicate balance between competing natural resources such as petroleum and water. However, the fact remains that, nationwide, much environmental compliance monitoring data is not yet in electronic format. Even in agencies where automated data systems exist, vast filing systems of wholly paper-bound archives provide the only access to important legacy background data. Obstacles to converting these archives to electronic databases include lack of funding and overstretched personnel resources.

Wise natural resource management requires access to caches of stored data for trend analyses and interpretation of the environmental effects of fossil fuel and mineral extraction operations on water quantity and quality. Even in agencies that do manage large amounts of data through client-server database applications, the extensive variability in the development tools used to create these systems and the differences in their form and function have created many technical obstacles in sharing data between the agencies and with the public. Overcoming the barriers created by early software programming and hardware choices has been difficult, with the result that large quantities of data historically have been accessible by only a few people. The increasing use of the Internet, however, points to the future of database development and implementation.

With the evolution from paper-based forms submittal and manual processing to electronic submittal, scanning, processing, and web-based publication of technical data, the states have spent the past two decades developing, continually improving, and incrementally rolling out GWPC's RBDMS. This transition is being accomplished within the constraints of agency workloads and program funding. Currently, 24 state oil and gas agencies use one or more modules of RBDMS.

RBDMS has been enhanced many times to include new features, such as modules for managing oil and gas production data and for tracking multilateral well construction details, downhole locations, inspection reports, and other monitoring data.

Information technology advances have cleared some of the hurdles to data usage and exchange of data between disparate databases and agency jurisdictions in areas such as:

- Conversion of paper archives to electronic databases in state agencies throughout the nation;
- Development of web interfaces to improve access to information and to provide gateways for data exchange where information is kept in proprietary databases;
- Application of Geographic Information Systems (GIS) technology to present data in a visual format (see Appendix 10);
- Use of monitoring data which exists in data systems spanning jurisdictional boundaries such as state oil and gas and water quality agencies, USGS, EPA, and USDA;
- Integration of oil and gas data with water quality, injection, and other environmental data streams; and,
- Electronic capture and submission of field data.

One of the more recent developments in data management involves the reporting of hydraulic fracturing chemicals. In 2010, the GWPC and the IOGCC began a joint project designed to set up a nationwide, state-by-state data system capable of storing chemical disclosures and presenting them to the public on demand. This effort became known as FracFocus. The FracFocus system is an educational and disclosure presentation system designed to inform the public about the process of hydraulic fracturing and provide them with the means to see a report of the chemicals that were used on a particular hydraulic fracturing job. The FracFocus website, www.fracfocus.org, includes information on hydraulic fracturing and how it works, groundwater protection, chemical use, regulations by state, and disclosure presentation (Appendix 14). It also addresses frequent questions and includes a form for the public to use to pose questions. To date, more than 3,000 inquiries from the public have been addressed through this system. Although the system was initially designed to provide for voluntary submission of disclosures, as of July 1, 2014, 16 states had required or permitted use of the FracFocus system as their means of chemical disclosure, with several more pending.

The FracFocus system contains more than 77,000 chemical disclosures submitted by over 650 companies

Companies have been able to submit chemical disclosures to the FracFocus system since January of 2011. As of the writing of this report, over 77,000 disclosures had been submitted to the system by over 650 companies. These disclosures can be found by the public using a *Find a Well* search form that allows them to search by state, county, well name, operator, API number, and, more recently, by job date, ingredient name, and Chemical Abstract Service (CAS) number. Disclosures are presented in the Adobe® portable document file (PDF) format.

Information contained on FracFocus disclosures includes the location of the well by state, county, and coordinate location, the name of the oil and gas operator, the true vertical depth of the well, the volume of water or other fluid used as the base carrier fluid for the fracture job, and a list of the products, suppliers, ingredients, and their percentages by mass for each chemical used in the fracture job. (For further details about the FracFocus program, see "Chemical Disclosure" in the *Well Treatment, Stimulation and Fracturing* chapter.)

State agencies have historically developed and operated oil and gas databases tailored to meet their day-to-day state regulatory needs. Federal databases are not designed to provide the operational functionality of state databases, but they can use data from state database systems to provide a national picture of oil and gas operations. Recently, the GWPC began development of an "oil and gas data gateway" in partnership with the Energy Information Administration. This project is designed to link oil and gas data from various data systems together so that information contained in individual state databases, federal databases, and databases like FracFocus can be accessed through a single site. The value of this gateway is that data residing in individual data systems can be aggregated in a manner that facilitates cross-cutting analysis.

Special Programs

Many states have additional programs for enhancing environmental protection of water resources. One of the most widespread is the orphan well program utilized by many states to plug improperly abandoned wells when the well owners cannot be found or are unable to pay for proper abandonment. Of the states responding to a GWPC survey, 17 have an orphan well plugging program. More than 53,000 wells are in such programs nationwide and more than 15,000 improperly abandoned wells have been plugged by these programs during the past five years. All 17 of these programs use funds dedicated specifically to an orphan well fund to plug wells. California and Indiana both provide incentives for operators to "adopt" orphan wells for the purposes of putting them back into operation. Such allowances lessen the number of orphan wells and allow states to stretch their orphan well dollars further, while also putting formerly abandoned wells back into operation.

As noted earlier, some states have implemented processes designed to target inspections based on criteria such as enforcement history, environmental sensitivity, presence of wellhead protection areas, and other relevant factors. These programs allow states to utilize their staff resources in a manner that is the most efficient and provides the greatest environmental benefit. For example, Nebraska uses a GIS overlay of wellhead protection areas to design their well inspection program. Ohio provides the state geological survey with the opportunity to review and comment on Class II UIC permits based on seismic risk profiles.

The Kansas Corporation Commission operates a system called KOLAR (Kansas Online Automated Reporting System), which includes aerial photos of wellsites, pits, and tanks to identify nearby water bodies and enhance site inspections. Kansas also utilizes a sensitive area designation in its inspection program.

Each of the 27 state oil and gas agencies in the study maintains a website where the public can get access to agency actions such as permitting, regulations, hearings, helpful documents, and in some cases direct access to agency electronic files through web-based interfaces and GIS mapping programs.

In 2012 and 2013, the GWPC sponsored two forums, with DOE funding support, to address the topic of stray gas in groundwater. Groundwater investigations in a number of states identified well construction deficiencies or deterioration of wellbore integrity as contributing factors to stray gas incidents that have locally disrupted domestic water supply usage. During forums in Cleveland, OH and Grapevine, TX, state regulators, industry experts and other stakeholders discussed state wellbore integrity standards and improvements in wellbore construction and integrity monitoring standards that could effectively prevent future stray gas incidents. During the forums the issue of annular pressure monitoring was discussed. In this regard it was noted that Texas was the first state to mandate pressure monitoring at the bradenhead as a means to evaluate wellbore integrity. Pennsylvania, a state that has led in the development of methodologies for responding to and investigating stray gas incidents, also includes wellhead pressure monitoring requirements as part of their well construction rule amendments.

State Oil and Gas Regulatory Exchange (SOGRE)

The SOGRE is an important effort developed by the GWPC and the IOGCC as part of the States First initiative.[50] The goal of the Exchange, in support of the States First initiative generally, is to

50 *States First initiative*, IOGCC website, http://www.statesfirstinitiative.org/

help states institutionalize a process of continuous improvement of oil and gas regulatory programs. It is anticipated the SOGRE will be able to offer the following services by the end of 2014:

Information and Education Services

Examples of information and education service include, potential efforts such as a multi-state survey of field inspector salaries, technical workshops, or information gathered and exchanged between states experiencing common issues.

Assistance with Rule Updates

Depending on the type of assistance a state desires, the SOGRE will provide either peer reviews or peer consultations on particular regulatory topics, such as well integrity regulations or storage pit regulations. Peer reviews will be based on lists of "regulatory elements", developed for particular subjects over time, which are deemed by the SOGRE to be worthy of consideration when a state is updating its rules on a given topic. Peer consultations will draw on the expertise of regulatory peers in multiple states, but will not necessarily be based on formally adopted lists of regulatory elements. In addition to peer reviews and consultations, the SOGRE will, if requested, advise or assist states on multi-stakeholder reviews of one or more focused regulatory areas.

Convening Services

The SOGRE will convene forums for state policy and technical staff to share the way they do business, review internal operations, and open up opportunities for extrapolating effective practices from one state to another. The SOGRE will also sponsor multi-stakeholder forums for state policy and technical staff to meet with other interested stakeholders to discuss issues of mutual interest. Convening a forum on stray gas or seismic events, produced water, or improving data systems would be examples of such services.

Other Programs of the States First initiative

Class II UIC Peer Reviews

An integral part of the States First initiative is the Class II UIC Peer Review program. This program was begun as a stand-alone regulatory review process by the GWPC in the 1990's. Under the initial program more than a dozen states underwent a review of their Class II UIC programs. A report for each review was written and resides in the library at the GWPC main office in Oklahoma City. It was felt that the Class II UIC Peer Review program should be included as part of the SOGRE. The program has been revised to include current aspects of underground injection control including induced seismicity and the use of diesel fuel in hydraulic fracturing. The program involves a three-step process that includes state completion of a questionnaire, an in-state review by a team of two technical staff from UIC programs in other states, with participation from up to two observers from EPA regional UIC programs, and facilitation by GWPC staff and/or a contractor, and a final report by the review team that contains the team's findings, conclusions, and recommendations.

Inspector Certification Course

Another element of the States First initiative involves the certification of field inspectors. This program, which is an update to a previous course implemented by the IOGCC, is a coordinated effort with Penn State University, The University of Texas at Austin and the Colorado School of Mines. The certification course is designed to evaluate the knowledge and expertise of field inspectors against an established set of criteria and to certify those that meet the criteria. Under the previous Inspector Certification course 185 inspectors from 12 states received training.

Field inspection of wellsite in Geauga County, Ohio Source, Ohio DOGRM

KEY MESSAGES AND CONSIDERATIONS

For an overview of recent activities related to the key messages and suggested actions made in the 2009 report, see Appendix 13.

Key Message 1: Rules

Since 2009, states have made considerable overall progress on the areas tracked by this report. As oil and gas E&P has increased dramatically around the country, and notably in states without a recent history of oil and gas activity, the public has expressed increasing concern about the safety and environmental impact of oil and gas development. In response, state oil and gas regulatory agencies have revised their regulations to improve the quality of operations. The following subsection provides observations and suggests regulatory elements for consideration when rules are being revised.

Permitting

Trends:
Several elements of permitting have been adopted by a large number of states since 2009, including:

- Public notice required prior to issuance
- Permits denied or delayed if applicant is not in compliance
- Permits can be revoked for non-compliance

These suggest that regulators are acknowledging stakeholders and asserting agency authority to manage non-compliance on the part of operators at an early stage. These are positive trends which are likely to continue.

One emerging aspect of permitting is requiring a review of the geology around a wellbore to evaluate potential subsurface fluid pathways that could interfere with full containment during completion operations (sometimes referred to as "Area of Review"). Several states are considering such a requirement, and more should do so over the coming years. In a similar vein, more states are asking operators to provide analysis of stratigraphic confinement when well stimulation occurs close to a protected water zone or in uncertain geology. In most cases, when thousands of vertical feet separate the stimulated area and protected water zones, this analysis can be brief and serves an informational purpose. In the cases where stratigraphic containment is in doubt, such an analysis decreases the risk of protected water contamination when state rules also require appropriate operational modifications.

Considerations:

1(a): Continue trends toward transparency through the use of permitting as a compliance mechanism, and toward requiring an analysis of AOR and of confining zones with respect to particular well operations such as hydraulic fracturing

Formation Treatment/Stimulation/Fracturing

Trends:
Several major trends have emerged in this area over the past four years. A growing number of states are now directly regulating the practice of hydraulic fracturing, focused especially on disclosure of chemicals used in the practice, public and regulator notice of hydraulic fracturing activity prior to commencement, and monitoring and reporting of pressures during hydraulic fracturing. Other emerging trends include requirements for baseline water testing prior to, and monitoring following, hydraulic fracturing treatment; water sourcing reporting; and cement evaluation reporting.

Other trends have emerged slowly and consideration might be given to future use. One trend is requiring mechanical integrity testing prior to hydraulic fracturing treatment. Another is requiring that hydraulic fracturing be suspended upon discovery of a loss of mechanical or formation integrity. The existence of mechanical integrity means that materials within the well are isolated from the formation and protected water, while the lack of mechanical integrity means there is a risk of undesirable communication between well fluids and the formation or protected water. Testing for mechanical integrity prior to well stimulation, the period in which the well is under its greatest stress, is a preventative measure to ensure that the well is prepared to handle the high pressures associated with hydraulic fracturing. Monitoring hydraulic fracturing treatment pressures and other indicators during the treatment is essential to conducting a proper treatment, and also provides immediate feedback on subsurface problems. Unexpected pressure changes or pressures exceeding tolerances are indicative of a loss of mechanical integrity or a formation specific condition such as the existence of high pressure zones or natural fractures, and for worker safety and protection of subsurface resources, hydraulic fracturing operations should cease immediately upon discovery of these conditions and not recommence until the source of the problem is identified and a mitigation plan is in place.

Considerations:

1(b): Mechanical Integrity Testing requirements prior to well stimulation

1(c): Monitoring and reporting requirements during well stimulation, and suspension of well stimulation when mechanical or formation integrity is compromised

Well Integrity

Trends:

Proper well integrity is essential to protecting groundwater during construction, completion, and production. In recent years, key states have engaged in major revisions to their well integrity programs. Highlights of these revisions include:

- Increased protection of groundwater through enhanced cementing requirements
- Increased agency attention to the depths of groundwater when reviewing permits
- States that address intermediate casing are providing more detailed specifications, like cementing requirements
- More states are providing casing standards
- More states are requiring corrective actions when there's evidence of cement failure
- More states are requiring the use of cement evaluation logs under specifically defined circumstances
- More states are requiring notification prior to casing and cementing

Considerations:

None of the above policies are pursued universally, and this report encourages all consideration of these aspects of well integrity when appropriate. Several specific well integrity policies merit consideration including:

1(d): Comprehensive well integrity testing during construction, especially Formation Integrity Testing (or "shoe" testing) prior to drill out

1(e): Centralization standards for production/long string

1(f): Isolation of flow zones capable of over-pressurizing an annulus and corrosive zones

1(g): Providing standards for reconditioned casing

1(h): Specifying mix-water quality standards and requirements for free water content in cement

Temporary Abandonment

Trend and Consideration:

Most states allow operators to temporarily abandon wells following completion. Operators use this status for a variety of purposes, from delaying production until economically advantageous to delaying timely plugging of unproductive wells. The first use is to be encouraged while the latter use is to be discouraged. Recognizing this, state regulators are increasingly imposing stringent time limits on temporary abandonment status, while regularly renewing TA status under specific circumstances.

Well Plugging

Trends:

A properly plugged well will permanently protect groundwater and other natural resources surrounding the wellbore. While plugging principles have been well-established for decades, there are some notable trends in this area:

- More states are allowing operators to submit cement tickets in lieu of witnessing
- More states are specifying the method (e.g., pump and plug or "displacement") of plugging
- States are requiring more detailed reporting on plugging

Some of these trends are positive, but allowing operators to submit cement tickets in lieu of witnessing can be problematic because, unlike field inspector witnessing, a cement ticket is not a verifiable demonstration of either the amount or quality of the cement used, nor does it describe the methods used to place that cement.

Considerations:

1(i): Witnessing plugging operations in lieu of allowing the submission of cement tickets to satisfy reporting requirements

1(j): Cement placement across all protected water zones

Storage in Pits

Trends:

Various trends emerged regarding storage in pits. The number of states with competency standards for liners increased significantly, along with the number of states with a freeboard requirement. In addition, more states are specifying duration of use. Finally, several states have added requirements related to pit closure, including prior authorization, landowner notice, and soil sampling. There is a growing trend toward the use of modular, site-assembled containment structures, sometimes referred to as "above-ground pits." Along with greater use, the storage capacity of these units is also increasing. Some states are in various stages of developing regulations to address the design, construction, and operation of modular storage units. Significant environmental risks are associated with modular storage facilities if they are not properly designed, constructed, and maintained given that failure will typically be of catastrophic nature with an instantaneous and total loss of containment.

Considerations:

1(k): Permitting or authorization based on characteristics of the fluids stored

1(l): Specific design, construction, and operation requirements including liners, freeboard, leak detection, duration of use, and operator inspection and maintenance

1(m): Siting restrictions taking into consideration surrounding land use, proximity to drinking water sources, 100-year flood plain boundary, and separation from groundwater (confined and unconfined)

1(n): Closure specifications including disposition of fluids, solids, and liners from the pit, and site restoration

Storage in Tanks

Trends:

Fluid storage in above-ground, enclosed tanks is increasing. Currently, with the exception of secondary containment provisions, most states do not specify tank design, siting, or operation requirements.

Considerations:

1(o): Permitting or authorization based on the characteristics of the fluids being stored

1(p): Specifications that address design, construction, and operation of tanks, including tank materials, overfill prevention, spill containment, leak detection, and operator inspection, maintenance and record keeping

1(q): Siting evaluation taking into consideration surrounding land use, proximity to drinking water sources, and 100-year flood plain boundaries

1(r): Closure specifications including disposition of fluids and solids, tank removal and disposition, and site restoration

Transportation of Produced Water for Disposal

Trends:

The most common form of transportation of produced water is by truck. Although other transportation methods are in use, the focus of this regulatory evaluation was on produced water transporters and the results of this evaluation indicated that fewer than half of the oil and gas agencies surveyed required transporters to be permitted or required the recording of the volume of produced water transported off-lease.

Considerations:

1(s): Permitting or licensing of produced water transporters and the recording of the volume of produced water transported off-site

1(t): Use of MOU/MOA between oil and gas agency and other state agencies where the oil and gas agency does not directly regulate transportation of produced water

Produced Water Recycling and Reuse

Produced water recycling and reuse was a newly added element for the 2013 review. Therefore, there are no quantitative trends to specify. However, the data currently indicate that oil and gas agencies generally have not yet addressed this topic. While water reuse and recycling could have several environmental advantages, care should be taken to identify and address environmental issues inherent to these processes.

Considerations:

1(u): Chemical characterization and management of side streams

1(v): Regulation of use of produced water for purposes other than well stimulation

1(w): Design, construction, operation, and removal standards for recycled water pipelines

1(x): Use of MOU/MOA between oil and gas agency and other state agencies where the oil and gas agency does not directly regulate water recycling and reuse

Exempt Waste Disposal

Trends:

RCRA Subtitle C exempt waste disposal is widely regulated, with most oil and gas agencies addressing one or more elements reviewed, including on-site and off-site disposal of drill cuttings and application of produced water, waste oil, and/or tank bottoms to roads and lands.

Consideration:

1(y): Manifests for off-site disposal where appropriate

Spill Response

Trends:

The vast majority of states have regulations related to spill response that include agency notification on spills and on-site spill remediation. A smaller number of states specify a clean-up standard for spills.

Consideration:

1(z): Clean-up standards should be established that are relative to the characteristics of the material spilled and impacted media

Key Message 2: Emerging Issues

With the rapid expansion and rate of technological and operational advancement in the oil and gas industry in the United States over the past four years, a series of issues have emerged that were not tracked by the 2009 version of this report nor, because of their relative recent emergence as issues to be addressed, fully examined in the regulatory evaluation presented earlier in this report. However, these issues are worthy of presentation here and might be considered for more detailed state regulatory evaluations in the future.

Well Integrity

Proper well integrity is essential to protecting groundwater resources. Many aspects of well integrity are long standing and widely practiced, and the basics are likely universally understood. However, with an increasing number of operators and service companies of varying levels of expertise performing complex well stimulations in a more diverse set of basins, some less understood than others, regulators are pursuing a variety of new policies that could be summed up by the maxim, "look before you leap."

Before well stimulation can commence, and in some cases as a condition of permitting, regulators are increasingly looking for an analysis of stratigraphic containment and of potential conduits of fluids from the stimulated zone to protected water. Stratigraphic containment refers to the existence of impermeable layers between the stimulated zone and the shallowest zones of protected water. In most cases, this zone is thousands of feet thick, and stratigraphic containment is easy to show. However, when the zone is thinner or the geology is complex or unknown, in cases sometimes referred to as a "limited intervening zone" or a "minimum separation well," some states are requiring an analysis of whether there is sufficient isolation of protected groundwater — this analysis may include the specific hydrology and geophysical characteristics of the intervening zone, identifying geologic names and descriptions of penetrated formations, structural mapping, geomechanical analysis, and 3D modeling of fracture propagation. This analysis might be conducted by the operator or regulatory agency, and can inform how a stimulation job is structured to minimize the risk of groundwater contamination.

A related concept, "Area of Review," is borrowed from the UIC program for use in the production context. A growing handful of states require operators to examine the subsurface in the area around their proposed wells for natural and artificial conduits that penetrate the fractured zone and the stratigraphic containment zone and could potentially transmit formation or fracturing fluids to protected waters (in some cases, regulators undertake this analysis themselves). These potential conduits most frequently take the form of improperly abandoned wells or poorly constructed production wells. Operators might then be required to explain why these identified conduits do not present a risk of contaminating protected water by way of a mitigation plan to avoid the conduits, by working with operators of nearby production wells, or even by plugging proximate improperly abandoned wells. In areas of the country with a heavily faulted geology or a long history of dense oil and gas development, such analysis and possible mitigation measures may substantially decrease the risk of protected groundwater contamination.

During stimulation operations, two policies can help both operators and regulators decrease the risk of groundwater contamination and accidents that threaten worker health and safety — kick reporting, and mandatory suspension of stimulation operations when problems are encountered. Kick reporting, which is required in at least one state where the kick is significant enough to trigger certain management responses, helps regulators understand formations by indicating when and where the kick occurred and under what circumstances. By building a database of significant kicks, regulators can better judge blowout risks and respond accordingly. Suspension of operations under certain defined circumstances may seem obvious, but it is still worthwhile to consider such steps as not every operator can be relied upon to make the correct risk/reward calculation.

Finally, proper well integrity does not stop when production starts. By taking a lifecycle approach to well integrity, states may consider ways to decrease the risk of groundwater contamination and blowouts over the decades that a well is in production. Annular pressure and bradenhead monitoring is one example of this approach. States might determine whether there are significant numbers of wells exhibiting sustained annular pressure and consider developing programs to assess the risks and respond to those risks appropriately.

Water Sampling and Analysis

Sampling and analysis of water resources potentially impacted by the oil and gas well drilling, completion, and operation activities is an issue that is definitely a topic of discussion and debate and in a number of states already incorporated into regulatory requirements. In states where water sampling and analysis is required, differences exist in a number of details including the following.

- Radius from wellsite in which sampling will be performed;
- Number of required sampling locations and rationale for selecting these locations;
- Frequency of sampling events (including pre- and post-drilling sampling);
- Suite of analysis to be performed on each sample; and
- Reporting of analytical results.

As part of any data gathering effort, it is important to specify sampling and analysis procedures and quality assurance and quality control activities to provide a basis for evaluation of analytical results and assist in a determination of potential impacts.

Water Sourcing and Produced Water Management

Various factors, including drought conditions that heighten the visibility of competing water users for fresh water sources and limited choices for produced water disposal, are driving efforts to utilize alternate sources of water for well completions and the evaluation of options for managing produced water. Possible alternate water sources include brackish and/or saline groundwater and reuse of produced water. When utilizing these alternate water sources, some form of treatment may be required. As part of this treatment process, a waste stream consisting of a concentration of constituents removed from treated water is frequently generated. This waste stream must be managed and ultimately disposed in compliance with appropriate waste management rules and regulations and in a manner protective of human health and the environment. Thus the effort to minimize the fresh water footprint of well completion activities presents additional environmental risk components that must be properly addressed.

Produced water can potentially be treated in water treatment facilities designed to handle the range of constituents that are present. Previously mentioned in this report were the problems that have been documented when POTWs are used to treat produced water. Without sufficient pretreatment of the produced water, POTWs typically cannot effectively and reliably remove constituents present. In many cases, introducing produced water into a POTW treatment process adversely impacts the treatment system's capabilities resulting in non-compliance of the NPDES permit and adverse impact to the receiving water body.

Centralized waste treatment facilities specifically designed to handle produced water are an option as long as the treatment process can remove and/or reduce the constituent concentrations to a level that meets subsequent water use parameters (such as utilization for hydraulic fracturing of subsequent wells) or NPDES permit discharge limits. Allowing surface discharge of treated produced water presents challenges in both setting appropriate discharge limits and consistently treating the produced water to meet these limits. Produced water constituents vary between well locations and over time. The establishment of discharge limits requires a characterization of the fluid to be treated, which is difficult where the constituent concentrations vary widely. Similarly, the engineering of a water treatment facility capable of treating an influent with varying characteristics to specific discharge is difficult. The treatment process must be capable of producing a consistent effluent regardless of influent characteristics, weather conditions, and any equipment and/or facility mechanical issues.

It was previously noted that water treatment operations will produce a waste stream consisting of a concentration of constituents removed from the fluid as part of the treatment process. Options for management of these novel waste streams include disposal and beneficial reuse. In all cases the waste stream must be characterized and disposal or reuse options appropriately implemented based on this characterization.

In addition to treatment operations and waste stream management requirements, the use of brackish and/or saline groundwater and the reuse of produced water results in the need for increased storage capacity and additional transportation of this fluid. Storage facilities will be needed to hold the fluid before and after treatment and during the span of time from produced water generation until it is used for subsequent well completions. Additional transportation is required to move this fluid from the point of generation to and from storage locations, to and from treatment facilities, and to the point of reuse. Absent permanent infrastructure, transportation will be performed either by trucking or the use of temporary pipelines. In both cases, increased adverse environmental risks from potential leaks and spills must be appropriately addressed.

Naturally Occurring Radioactive Material (NORM)

Radium forms naturally from the decay of uranium and thorium, elements that commonly occur in sandstones and shales in sedimentary environments. Radium's two principal isotopes, radium-226 (Ra-226) and radium-228 (Ra-228) have been documented in the formation waters in many sedimentary basins, and have been measured in water co-produced with oil and gas. Concentrations of NORM in formation water vary regionally and depend on variations in the background radiation of surrounding sedimentary rock. During E&P activities, NORM can be brought to the surface in produced water and drill cuttings and may end up being present in other equipment and facilities that routinely come in contact with these materials. As a radioactive element, radium may represent a potential health hazard if released into the environment where Ra-226 and Ra-228 can accumulate in plants and animals, water, and clay sediments.[51] State regulations and guidance regarding the proper disposal, handling and exposure limits for NORM in materials associated with oil and gas development is still in its nascent stages but is an emerging field for regulation, particularly in states overlying the Appalachian Basin.

Key Message 3: Regulatory Coordination

Coordination of effort is a key component of effective regulation. To properly and effectively regulate E&P activities state, local, and federal regulatory agencies should communicate routinely and develop MOAs and MOUs that describe the jurisdictional nexus between regulatory agencies within a state, between state, local and federal agencies and between individual states. While most states have developed some interagency agreements that define the boundaries of each agencies' responsibilities and some have even developed agreements between states (e.g., Agreement between Texas and Louisiana regarding UIC issues), care must be taken to ensure that these agreements become the framework for day-to-day operational regulation.

Considerations:

3(a): Interagency and interstate communication on issues of regulatory importance should continue to remain a priority

3(b): Agreements should be incorporated into proce-

51 USGS, *Radium Content of Oil- and Gas-Field Produced Waters in the Northern Appalachian Basin (USA)*, Scientific Investigations Report 2011-5135 (2011); Pennsylvania Dep't of Envtl. Protection, Oil and Gas Related Topics: Radiation Protection, Oil & Gas Development Radiation Study, http://www.portal.state.pa.us/portal/server.pt/community/oil_gas_related_topics/20349/radiation_protection/986697.

dural documents agencies use to implement regulatory programs

3(c): Coordination of action at the field level should be stressed and should be incorporated into the agency culture to avoid jurisdictional gaps that could result in environmental harm

Key Message 4: Data Management

The capture, storage, and communication of information are major parts of any regulatory program. Timely access to accurate and comprehensive information about well construction, testing, field inspections, compliance and a host of other data can provide agency personnel with the means to evaluate and make appropriate decisions regarding the application of regulations. Field access to information and the ability to capture and transfer data bi-directionally between the field and an agency office is a key component of most state programs. Additionally the continued transfer of agency information from hard copy to electronic formats is facilitating the process of data access.

Considerations:

4(a): Rapid and comprehensive access to regulatory information at both the office and field level should remain a priority, and processes that enhance this ability should be implemented whenever possible

4(b): Consideration should be given to providing information to the public through web enabled systems, both to decrease the level of effort currently expended in fulfilling public records requests and to improve regulatory transparency

4(c): Connecting disparate data systems to provide a broader range of information through accessible portals and to facilitate data exchange should be a priority

Key Message 5: Foundational Scientific Research

Research into the scientific principles related to areas of concern is a critical part of determining the relative risk of activities. Dissemination of the information learned from research is necessary to help the regulatory community evaluate and, where needed, take appropriate action to protect water resources.

Considerations:

5(a): Basic scientific research related to field operations that could potentially affect the protection of water resources should be encouraged and facilitated. Specific areas of research needed include but are not limited to:

- **5(a)(1):** Evaluations of the risks associated with NORM and TENORM
- **5(a)(2):** Evaluations of the extent, causes, and risks of induced seismicity
- **5(a)(3):** Comprehensive and focused research into the relative risk to surface water and groundwater posed by the practice of hydraulic fracturing specifically and E&P operations generally
- **5(a)(4):** Continued research into the characterization and occurrences of stray gas migration relative to natural conditions and human activities
- **5(a)(5):** Characterization of formation water and produced water in order to: (1) facilitate the use of brackish water supplies and recycling; and (2) inform regulatory oversight of treatment and discharge when produced water is neither recycled nor sent to disposal wells

5(b): Conferences and symposia focusing on the results of scientific studies should be held to disseminate information learned through research

[This page is intentionally blank]

ACRONYMS & TERMS

ACRONYM/ TERM	MEANING
ANSI	American National Standards Institute
Annulus	The space between two casing strings or a casing string and a borehole
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BHP	Bottom Hole Pressure
Biocide	An ingredient added to a fluid to prevent the growth of biologic organisms
BLM	Bureau of Land Management, U.S. Department of the Interior
Bradenhead	A casing head in an oil well having a stuffing box packed (as with rubber) to make a gastight connection
CBM	Coalbed Methane (Also known as Coalbed Natural Gas)
CBL	Cement Bond Log
Cement	A mixture of cement and water with no aggregates included. Commonly referred to as "Portland" or "neat" cement. NOTE: Cement may also contain additives used for specific purposes in oil and gas drilling and well completion
Centralizer	A device that is placed on the outside of a casing string to keep the casing centered inside the wellbore.
CIBP	Cast Iron Bridge Plug
CWA	Clean Water Act of 1977 (Successor to the Federal Water Pollution Control Act of 1972)
DOE	U.S. Department of Energy
E&P	Exploration and Production
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
Friction reducer	An ingredient added to a fluid to minimize the friction between the fluid and the casing through which it is being pumped
Gas	Means natural gas consisting of "hydrocarbons which at atmospheric conditions of temperature and pressure are in a gaseous phase"[22]
Groundwater	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
GWPC	Ground Water Protection Council
Hydraulic Barrier	A natural or artificial barrier through which the flow of fluid is substantially inhibited
Hydraulic Fracturing	The practice of pumping fluids and proppant under pressure into a rock formation for the purpose of causing fractures in the rock matrix and propping open the fractures to create preferential flow pathways.
IOGCC	Interstate Oil and Gas Compact Commission
Kick	Unintended intrusion of high pressure oil or gas into a wellbore
Matrix treatment	A well treatment designed to return the formation to its original condition. Acid jobs are an example of a typical matrix type of treatment.
NETL	National Energy Technology Laboratory
NORM	Naturally Occurring Radioactive Material (When concentrated by human activity it is typically referred to as TENORM-Technically Enhanced Naturally Occurring Radioactive Material)

ACRONYM/ TERM	MEANING
NPDES	National Pollutant Discharge Elimination System
OGAP	Oil and Gas Accountability Project
Packer	A device that can be run into a wellbore with a smaller initial outside diameter that then expands externally to seal the wellbore. Packers are used as barriers within the well, as seats for tubing and for other purposes.
Permeability	A measure of the resistance offered by rock to the movement of fluids through it.[22] (Note: As used in this report, the term also applies to non rock materials such as soil, clay etc...)
Plugging	The process of sealing a well with cement and other materials as a means of permanent closure
POTW	Publicly Owned Treatment Works (A water treatment facility designed to treat water for public use)
Proppant	A solid material (usually sand or ceramic beads) used to prop open the fractures created during the process of hydraulic fracturing.
RCRA	The Resource Conservation Recovery Act of 1976 and amendments
SDWA	The Safe Drinking Water Act of 1974 and amendments
Side streams	Constituents removed from fluids during the treatment process
SPCC	Spill Prevention Countermeasures and Control
STRONGER	State Review of Oil and Natural Gas Environmental Regulation
TA	Temporary abandonment of a well
TDS	Total Dissolved Solids (Typically reported in mg/L or Parts Per Million (PPM))
TPH	Total Petroleum Hydrocarbons (Typically reported as a % by volume or in Parts Per Million)
UIC	The Underground Injection Control program authorized by the SDWA
UL	Underwriters Laboratory
USDW	Underground Source of Drinking Water as defined in 40 CFR Part 144.3
VDL	Variable Density Log

Appendix 1

Survey of State CBM Hydraulic Fracturing Practices, February 2008
(Selection of states based on the DOE Map of Major and Minor Coal Producing States 12/31/2000)

	Question: Is diesel used as a fracture fluid additive for CBM zones that are also USDW's?			
State	**Person Contacted**	**Date**	**Yes/No**	**Additional Notes**
Alabama	Dave Bolin, Alabama State Oil and Gas Board	12/13/2007	No	
Alaska	Jim Regg , Alaska Oil and Gas Conservation Commission	12/19/2007	No	
Arizona	Steve Rauzi, Arizona Geological Survey	2/11/2008	No	(No CBM production)
Arkansas	Lawrence Bengal, Arkansas Oil and Gas Commission	2/12/2008	No	
Colorado	Tricia Beaver, Colorado Oil & Gas Conservation Commission	12/14/2007	No	
Illinois	Doug Shutt, Illinois Division of Oil and Gas	2/8/2008	No	
Indiana	Mona Nemecek, Indiana Division of Oil and Gas	2/7/2008	No	
Kansas	Alan Snider, Kansas Corporation Commission	12/14/2007	No	(No USDW CBM zones)
Kentucky	Marvin Combs, Kentucky Division of Oil and Gas	2/8/2008	No	(No CBM production)
Louisiana	Jim Welsh, Louisiana Office of Conservation	2/11/2008	No	(No USDW CBM zones)
Maryland	Ed Larrimore, Maryland Department of Environment	2/11/2008	No	(No CBM production)
Mississippi	Lisa Ivshin, Mississippi Oil and Gas Board	2/11/2008	No	(No CBM Production)
Montana	Tom Richmond, Montana Board of Oil & Gas Conservation	12/13/2007	No	
New Mexico	Mark Fesmire (Former director), New Mexico Oil Conservation Division	2/7/2008	No	
North Dakota	Mark Bohrer, North Dakota Oil and Gas Commission	2/7/2008	No	(No CBM production)
Ohio	Scott Kell, Ohio Department of Natural Resources	12/13/2007	No	
Oklahoma	Lori Wrotenbery, Oklahoma Corporation Commission	12/26/2007	No	(No USDW CBM zones)
Pennsylvania	Dave English, Pennsylvania Department of Environmental Protection	12/14/2007	No	
Tennessee	Mike Burton, Tennessee Oil and Gas Board	2/8/2008	No	(No CBM production)
Texas	Leslie Savage, Texas Railroad Commission	2/12/2008	No	
Utah	John Baza, Utah Department of Natural Resources	12/13/2007	No	
Virginia	Bob Wilson, Virginia division of Gas and Oil	12/14/2007	No	(No USDW CBM zones)
Washington	Ron Teissere, Washington Department of Natural Resources	2/11/2008	No	
West Virginia	James Martin, West Virginia Department of Environmental Protection	12/14/2007	No	
Wyoming	Janie Nelson, Wyoming Oil & Gas Conservation Commission	12/19/2007	No	

Appendix 2

Oil and Gas Production by State Sorted by Oil Production Ranking for 2013

State	Oil Production (000) bbls.	Gas Production (Mmcf)
Texas	88432	7475495
North Dakota	28620	179004
California	17236	246822
Alaska	16923	351259
Oklahoma	9462	2023461
New Mexico	8667	1215773
Louisiana	6117	2955437
Colorado	5509	1709376
Wyoming	5270	2022275
Kansas	3749	296299
Utah	3099	490393
Montana	2102	66954
Mississippi	1986	63843
Alabama	886	215710
Illinois	790	2125
Michigan	682	129333
Ohio	649	84482
Arkansas	565	1146168
Pennsylvania	491	2256696
West Virginia	354	529860
Nebraska	307	1328
Kentucky	254	106122
Florida	196	18681
Indiana	196	8814
South Dakota	156	15085
New York	30	26424
Nevada	27	4
Tennessee	22	5825
Missouri	18	0
Arizona	3	117
Virginia	1	146405

Source: U.S. Energy Information Administration, 2013 oil and gas production figures

Appendix 3

List of 2013 Matrix areas of State Oil and Gas Regulations Related to Water Protection and numbers of states with requirements

Areas and Related Elements	Number of States in 2009	Number of states in 2013
1 General Authority		
1 Agency has a definition of groundwater that is used as a protective measure	N/A	27
2 Permitting		
2A Types of permits/ prior authorizations required		
2A1 Drilling, re-drilling, workover, conversion etc…	27	27
2A2 Plugging	22	22
2A3 Treatment, Stimulation or Fracturing	8	10
2A3a A review of the area around the wellbore and within the reach of the horizontal axis of the wellbore is required to check for natural and artificial conduits	N/A	4
2A3b A review of the geology and separation interval between the fractured zone and protected groundwater zones is required	N/A	5
2A4 Land application of exempt waste	13	14
2A5 Storm water (e.g. wellsite construction)	5	7
2A6 Discharge to POTW or treatment facility	N/A	6
2A7 Discharge to commercial Class II disposal well	N/A	24
2B Public notice required prior to issuance	7	16
2C Permits can be denied or delayed if applicant is not in compliance	11	20
2D Permits can be revoked for non compliance	9	20
3 Formation Treatment, Stimulation or Fracturing		
3A Specific regulations governing practice	4	13
3B Prior authorization required	8	10
3C Public notice required	1	6

Appendix 3 *continued*

3D Specific requirements	4	4
3D1 Specific materials/ chemicals prohibited (e.g. diesel fuel, 2-BE, etc…)	3	4
3D2 Agency requires submission of specific information about constituents	5	12
3D3 Inspector witnessing required	2	2
3D4 Pressure limitations specified	1	7
3D5 Minimum Depth Required	2	2
3D6 Adjacent water well testing and monitoring required	2	5
3D7 Wellbore mechanical integrity test before commencement of fracturing or re- fracturing required	N/A	7
3D8 Monitoring and recording of stimulation operations required throughout the stimulation process	N/A	8
3D9 Cessation of operation is required upon evidence of mechanical integrity breach or failure	N/A	9
3D10 Surface equipment mechanical integrity test before commencement of fracturing or re-fracturing required.	N/A	2
3D11 Fracturing fluid must be confined to the target reservoir	N/A	4
3E Reporting required	21	21
3E1 Materials	16	20
3E2 Volumes	17	20
3E3 Chemicals	9	21
3E4 Pressures	9	11
3E5 Depths	20	22**
3E6 Perforation intervals	N/A	19
3E7 Cement evaluation logs required under specific conditions	N/A	12
3E8 Wellbore schematic including hole size and casing size for each string	N/A	17
3E9 Volumes of water used for hydraulic fracturing reported by category (e.g. recycled, fresh, brackish, saline)	N/A	10
4 Well Integrity		
4A Surface casing through and below all protected groundwater zones required	25	25
4A1 Cementing from bottom to top required	26	27
4A2 The depths of protected groundwater are determined or approved by regulator on a well-specific basis or defined by rule	N/A	26
4A3 Casing shoe extends below the base of protected groundwater adjacent to a competent formation	N/A	14
4A4 Centralizers required at intervals sufficient to provide for zonal isolation by the cement	N/A	6

Appendix 3 *continued*

4A5 Surface casing string is pressure tested prior to drill-out to verify casing integrity and cement placement	N/A	13
4A6 Formation Integrity Test/Shoe Test following drill-out of surface casing string required	N/A	4
4B Intermediate casing required	13	14
4B1 Cementing from bottom to top required	4	9
4B2 Cementing from bottom to next cemented string required	5	9
4B3 Cementing from bottom to specific distance above bottom required	11	16
4B4 Cementing of casing as necessary to isolate protected groundwater encountered below the casing seat required	N/A	1
4B5 Cementing of casing as necessary to isolate flow zones capable of over-pressurizing any casing annulus or adversely affecting the cement job required	N/A	15
4B6 Cementing of casing as necessary to isolate corrosive zones required	N/A	13
4B7 Minimum standard for the height of cement above the zones that are sealed and isolated required	N/A	6
4B8 Centralizers required at intervals sufficient to provide for zonal isolation by the cement	N/A	16
4B9 Casing string must be pressure tested prior to drill-out to verify casing integrity and cement placement	N/A	5
4B10 Formation Integrity Test/Shoe Test following drill-out of intermediate casing string required	N/A	14
4C Long/Production string casing required	24	24
4C1 Cementing from bottom to top required	6	6
4C2 Cementing from bottom to next cemented string required	6	6
4C3 Cementation from bottom to specific distance above bottom required	18	21
4C4 Cementing of casing as necessary to isolate protected groundwater encountered below the surface casing seat required	N/A	13
4C5 Cementing of casing as necessary to isolate flow zones capable of over-pressurizing any casing annulus or adversely affecting the cement job required	N/A	11
4C6 Cementing of casing as necessary to isolate corrosive zones required	N/A	6
4C7 Minimum standard for the height of cement above the zones that are sealed and isolated required	N/A	19
4C8 Centralizers required at intervals sufficient to provide for zonal isolation by the cement	N/A	7
4C9 Casing string must be pressure tested prior to drill-out to verify casing integrity and cement placement	N/A	17

Appendix 3 *continued*

4D Casing must meet API Standards	5	7
4D1 Casing must be properly rated for expected conditions	N/A	10
4D2 Specific regulations for use of reconditioned casings	N/A	8
4E Cement must meet API standards	4	8
4E1 Established limit on free water in cement	N/A	5
4E2 Mix water quality is evaluated with respect to the cement being used	N/A	6
4E3 Authority to require specific blends to isolate problematic zones	N/A	10
4E4 Cement slurry must be mixed and pumped at a rate to maintain consistent density	N/A	2
4F Cement evaluation logs or other approved methods are required under specifically defined circumstances	9	14
4G Cement set-up period (Wait On Cement time) required before resuming drilling based on compressive strength standards	20	20
4H Does the rule place a limitation on the constituents of drilling fluid (Please define)	N/A	9
4I Operator required to notify an inspector prior to installing casing and/or commencing cementing operations	5	11
4J Borehole conditioning	N/A	2
4J1 Mud removal prior to cement emplacement required	N/A	1
4J2 Circulation must be established prior to commencement of cementing, if technically feasible	N/A	2
4J3 If circulation cannot be established, standards address how cement seals will be emplaced to effectively isolate specified zones	N/A	2
4J4 Borehole must be essentially static prior to cement circulation	N/A	4
4K Casing pressure test at a pressure greater than the anticipated fracture pressure required prior to fracturing	N/A	4
4L Minimum annular space of at least 0.75”, between each wellbore and casing, or each casing/ casing annulus required	N/A	5
4M Corrective action required if there are circulation problems or other indicators of deficient/defective cement	N/A	17

Appendix 3 *continued*

5 Temporary Abandonment		
5A Temporary abandonment allowed	25	26
5B Prior authorization required	24	25
5C Renewal allowed	24	26
5D Duration of TA/ Shut-in status limited	9	11
5E Well integrity demonstration or specific construction required	20	20
6 Production Operations		
6 Post-completion tubing, casing, and Braden head pressures are monitored	N/A	9
7 Well Plugging		
7A Cementing or removal of uncemented casing required	17	20
7B Cement must meet API standards	8	12
7C Materials other than cement allowed (e.g. bentonite) when consistent with performance objectives Note: Except for spacers	10	11
7D Cement placement above producing zones required	22	25
7E Cement placement across all protected water zones required	22	22
7F Wellbore must be essentially static at the time cement plugs are emplaced	N/A	8
7G Bridge plugs required	6	10
7H Standards specify the thickness and spacing of required plugs	N/A	19
7I Plugging plan submission prior to plugging required	20	21
7J Standards specify when and how the plugs must be tagged or tested	13	13
7K Timeframes established for plugging dry holes, inactive wells	N/A	20
7L Notice of intent to plug required	22	26
7M Cement tickets allowed in lieu of witnessing	5	16

Appendix 3 *continued*

7N Plug tagging/ placement verification required	13	13
7O Cement plug strength specified	6	6
7P Plugging method specified	14	17
7P1 Pump and plug required	7	10
7P2 Dump bailing allowed	21	21
7P3 Bullhead plugging allowed	N/A	17
7Q Reporting required	26	27
7Q1 Cement type (e.g. Class A)	17	17
7Q2 Cement volume (e.g. Sacks or Cu. Ft.)	18	21
7Q3 Bridge plugs (e.g. CIBP, Cement Retainer etc…)	17	24
7Q4 Casing left	20	25
7Q5 Plug placement intervals	20	24
7Q6 Timeframe for reporting established	N/A	26
8 Storage in Pits		
8A Pit types allowed		
8A1 Drilling/ workover	27	27
8A2 Salt water storage	19	20
8A3 Waste storage	10	14
8A4 Emergency	12	14
8A5 Burn Off	6	8
8A6 Temporary oil storage	5	6
8B Prior authorization required	19	18*
8C Prior surface owner notification required	6	6
8D Inspection before use required	7	10
8E Construction requirements		
8E1 General	17	17
8E2 Specific	14	14

Appendix 3 *continued*

8E3a Design requirements for storage pits	N/A	12
8E2b Modular, site-assembled containment structures prohibited	N/A	1
8E2c Leak detection	N/A	9
8E3 Liners required	23	23
8E3a Liner inspection in lieu of direct leak detection methods allowed	N/A	9
8E3b Compatibility of liner with stored fluids and setting evaluated	N/A	9
8E3c Natural allowed	17	18
8E3d Artificial required	12	12
8E3e Competency standards specified	15	22
8E3f Seaming standards specified	7	12
8E3g Bed preparation standards specified	12	12
8E3h Reporting of detected leaks required	N/A	13
8E3i Corrective action in response to leaks required	N/A	18
8F Freeboard required	16	20
8G Siting or Setback requirements		
8G1 Distance from surface water specified	10	13
8G2 Prohibited in water table	12	13
8G3 Vertical separation from water table specified (seasonal fluctuations addressed?)	N/A	11
8G4 Siting within 100 year floodplain and/ or in floodway allowed	N/A	12
8G5 Setback from drinking water sources (groundwater or surface water) required	N/A	7
8H Inspection during operation required	N/A	12
8I Duration of use regulated	16	23
8J Closure requirements		
8J1 Prior authorization required	6	12
8J2 Prior notice to surface owner required	1	3
8J3 Soil sampling required	3	8
8J4 Closure report required	5	7
8J5 Site restoration to prior use mandated	N/A	10
8J6 Closure can be waived with landowner permission	N/A	10
9 Storage in Tanks		
9A Prior authorization required	5	5

Appendix 3 *continued*

9B Inspection of tanks before use required	1	2
9C Design and construction standards established	N/A	7
9C1 Tank materials specified	5	7
9C2 ASTM, ANSI, API or other technical specifications required	1	1
9C3 Maximum volume per tank specified	N/A	1
9C4 Maximum aggregate tank volume per site specified	N/A	1
9C5 Are tanks with 10% or more volume (including piping) below ground surface allowed	N/A	8
9C6 External level meters/monitors required	N/A	3
9C7 Overfill controls required	N/A	3
9C8 Pre-construction plans must be submitted to agency	N/A	3
9D Siting or setback requirements		3
9D1 Distance from surface water specified	2	4
9D2 Depth to ground water considered	0	2
9D3 Siting within 100 year floodplain and/ or in floodway allowed	3	11
9D4 Setback from drinking water sources (groundwater or surface water) required	N/A	4
9E Secondary containment required	22	23
9E1 Capacity specified	20	21
9E2 Permeability specified	11	12
9E3 Maintenance and on-going inspections required	16	16
9E4 Standing fluids in containment area prohibited	13	16
9E5 Surface discharge of waste fluids in containment area regulated	17	17
	N/A	2
9F Tank removal and site restoration requirements	N/A	6
9F1 Site restoration to prior use mandated	N/A	8
9F2 Soil sampling required	N/A	2
9F3 Closure report required	N/A	5
9G Requirement for certain wellsite fluids to be maintained in tanks	N/A	4
10 Transportation of Produced Water for Disposal		
10A Permitting of produced water transporters	N/A	10
10B Manifests/trip tickets recording volume of produced water transported off-site required	N/A	12

Appendix 3 *continued*

11 Produced Water Recycling and Reuse		
11A Produced water treatment specifically regulated	N/A	5
11A1 Regulations specific to side streams (solid and liquid) generated as part of produced water treatment	N/A	4
11A2 Chemical characterization of side streams (solid and liquid) required	N/A	3
11B Produced water used for purposes other than well stimulation allowed	N/A	17
11C Produced water used for drilling mud for drilling of surface casing portion of the well allowed	N/A	7
11D Design and construction standards for recycled water pipelines	N/A	1
11E Recycled water pipeline operations	N/A	2
11E1 Pressure and flow monitoring required	N/A	1
11E2 Leak detection required	N/A	2
11E3 Response actions to address leaks required	N/A	4
11E4 Re-inspection and testing after pipeline repairs prior to resuming operation required	N/A	2
11F Recycled water pipeline removal required	N/A	4
12 Exempt Waste Disposal		
12A On site- disposal of waste regulated	23	23
12A1 Specific waste constituents regulated	N/A	19
12A2 Quantities of waste disposed on-site documented	N/A	4
12B Application of salt water to roads/ lands regulated	18	20
12B1 Application rates specified	N/A	6
12B2 Quantities of material applied on roads/lands documented	N/A	6
12C Application of tank bottoms and waste oil to roads/ lands regulated	16	17
12C1 Application rates specified	N/A	8
12C2 Quantities of material on roads/lands documented	N/A	6
12D On-site disposal of drill cuttings regulated	N/A	21
12E Beneficial re-use of drill cuttings regulated	N/A	12
12F Off-site disposal of drill cuttings regulated	N/A	16

Appendix 3 *continued*

12G Off-site reuse of other waste reuse regulated	N/A	10
12H Manifests for off-site disposal required	N/A	9
13 Spill Response		
13A Spills regulated by the agency	23	23
13B Agency notification of spills required (Within what time period?)	23	24
13B1 Volume of spill threshold to trigger notification	N/A	22
13C Landowner notification of spills required (Within what time period?)	3	4
13C1 Volume of spill threshold to trigger notification	N/A	3
13D On-site spill remediation regulated	20	20
13E Cleanup spill standards specified	12	13

N/A means this element was not reviewed in 2009

* This number does not represent a drop in states but rather, a recognition that one state had a notification rather than an authorization requirement

**This number is greater than the total reporting number because it includes information captured on Well Completion or Re-completion reports.

Appendix 4

Text of the Memorandum of Agreement between USEPA and BJ Services Company, Halliburton Energy Services, Inc. and Schlumberger Technology Corporation

Authors Note: Although reformatted from the original file for this report, this appendix contains the unabridged text of the agreement minus the actual signature pages of the parties.

A MEMORANDUM OF AGREEMENT
Between
THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
And
BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation

Elimination of Diesel Fuel in Hydraulic Fracturing Fluids Injected into Underground Sources of Drinking Water During Hydraulic Fracturing of Coalbed Methane Wells

12 December, 2003

I. PREAMBLE

A. This is a voluntary agreement between the United States Environmental Protection Agency (EPA) and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation (the service companies are collectively referred to as the "Companies;" individually as "Company"), by which the Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into coalbed methane (CBM) production wells in underground sources of drinking water (USDWs) and, if necessary, select replacements that will not cause hydraulic fracturing fluids to endanger USDWs. While the Companies do not necessarily agree that hydraulic fracturing fluids using diesel fuel endanger USDWs when they are injected into CBM production wells, the Companies are prepared to enter into this agreement in response to EPA's concerns and to reduce potential risks to the environment.

Appendix 4 *continued*

B. Hydraulic fracturing is a technique used by the oil and gas industry to improve the production efficiency of production wells, including CBM production wells. A hydraulically-created fracture acts as a conduit in the rock or coal formation that allows the oil or gas to travel more freely from the rock pores. To create such a fracture, a viscous, water-based fluid is sometimes pumped into the coal seam under high pressures until a fracture is created. These fluids consist primarily of water, but in some cases they also contain various additives. Diesel fuel has been used as an additive in hydraulic fracturing fluids for the purpose of enhancing proppant delivery.

C. The Companies and EPA recognize that the primary purpose of this agreement is to eliminate the use of diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs.

II COMMON AGREEMENTS AND PRINCIPLES

A. The Companies and EPA acknowledge that only technically feasible and cost effective actions to provide alternatives for diesel fuel will be sought. The determination of what is technically feasible and cost-effective will vary and it is at the discretion of each Company to make that determination.

B. The Companies and EPA will exercise good faith in fulfilling the obligations of this Memorandum of Agreement (MOA).

C. Nothing in this agreement constrains EPA or the Companies from taking actions relating to hydraulic fracturing that are authorized or required by law. Nothing in this agreement should be understood as an EPA determination that use by the Companies of any particular replacement for diesel fuel is authorized under the Safe Drinking Water Act (SDWA) or EPA's Underground Injection Control (UIC) Regulations, or that the elimination of diesel fuel or use of any replacement fluid constitutes or confers any immunity or defense in an action to enforce the SDWA or EPA's UIC regulations. Nothing in this Agreement shall, in any way, be considered a waiver of the Companies' right to challenge any subsequent regulations or limitations on the use of hydraulic fracturing or its components by any state or Federal agencies.

D. All commitments made by EPA in this MOA are subject to the availability of appropriated funds and Agency budget priorities. Nothing in this MOA, in and of itself, obligates EPA to expend appropriations or to enter into any contract, assistance agreement, interagency agreement, or other financial obligations. Any endeavor involving reimbursement or contribution of funds between EPA and the Companies will be handled in accordance with applicable laws, regulations, and procedures, and will be subject to separate agreements that will be effected in writing by representatives of the Companies and EPA, as appropriate.

Appendix 4 *continued*

E. EPA and the Companies will bear their own costs of carrying out this agreement. The Companies agree that activities undertaken in connection with this MOA are not intended to provide services to the Federal government, and they agree not to make a claim for compensation for services performed for activities undertaken in furtherance of this MOA to EPA or any other Federal agency.

F. Any promotional material that any Company develops may advise the public of the existence of this MOA and its terms, but must not imply that EPA endorses the purchase or sale of products and services provided by any Company

G. This MOA does not create any right or benefit, substantive or procedural, enforceable by law or equity against the Companies or EPA, their officers or employees, or any other person. Nothing herein shall be deemed to create any requirement under any existing law or regulation**.** This MOA does not direct or apply to any person outside the Companies and EPA.

III. EPA ACTIONS

A. To the extent consistent with Agency authorities and policies governing recognition awards, EPA agrees to consider providing the Companies with recognition for their achievements in replacing diesel fuel in fracturing fluids injected into USDWs for CBM production and for their public service in protecting the environment. In addition, EPA agrees to provide appropriate information to the public, other Federal agencies and Congress, regarding actions taken by the Companies under this MOA. EPA agrees to obtain the Companies' approval on any specific language intended for public distribution that discusses the Companies' participation in this MOA and agrees to notify the Companies sufficiently in advance of EPA's intention to publicly use the Companies' name or release information, including press releases, concerning the Companies' participation in this MOA.

B. EPA agrees to contact appropriate individuals representing states, industry, and the Department of Energy to inform them of progress in implementing the MOA and to solicit their cooperation, as appropriate, in implementation of the MOA.

C**.** EPA agrees to issue a final version of the draft report entitled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* as soon as reasonably possible.

D. The parties agree that nothing in this MOA is intended to affect, in any way, the existing criteria and process for identifying exempted aquifers under 40 C.F.R. Parts 144 and 146.

Appendix 4 *continued*

E. EPA agrees to consider other measures as appropriate to aid implementation of the MOA, including measures to facilitate efforts undertaken by the Companies pursuant to this MOA.

IV. THE COMPANIES' ACTIONS

A. The Companies agree to eliminate diesel fuel in hydraulic fracturing fluids injected into CBM production wells in USDWs within 30 days of signing this agreement. If necessary, the Companies may use replacement components for hydraulic fracturing fluids that will not endanger USDWs.

B. The Companies agree to notify the Assistant Administrator for EPA's Office of Water within 30 days after any decision to re-institute the use of diesel fuel additives in hydraulic fracturing fluids injected into USDWs for CBM production.

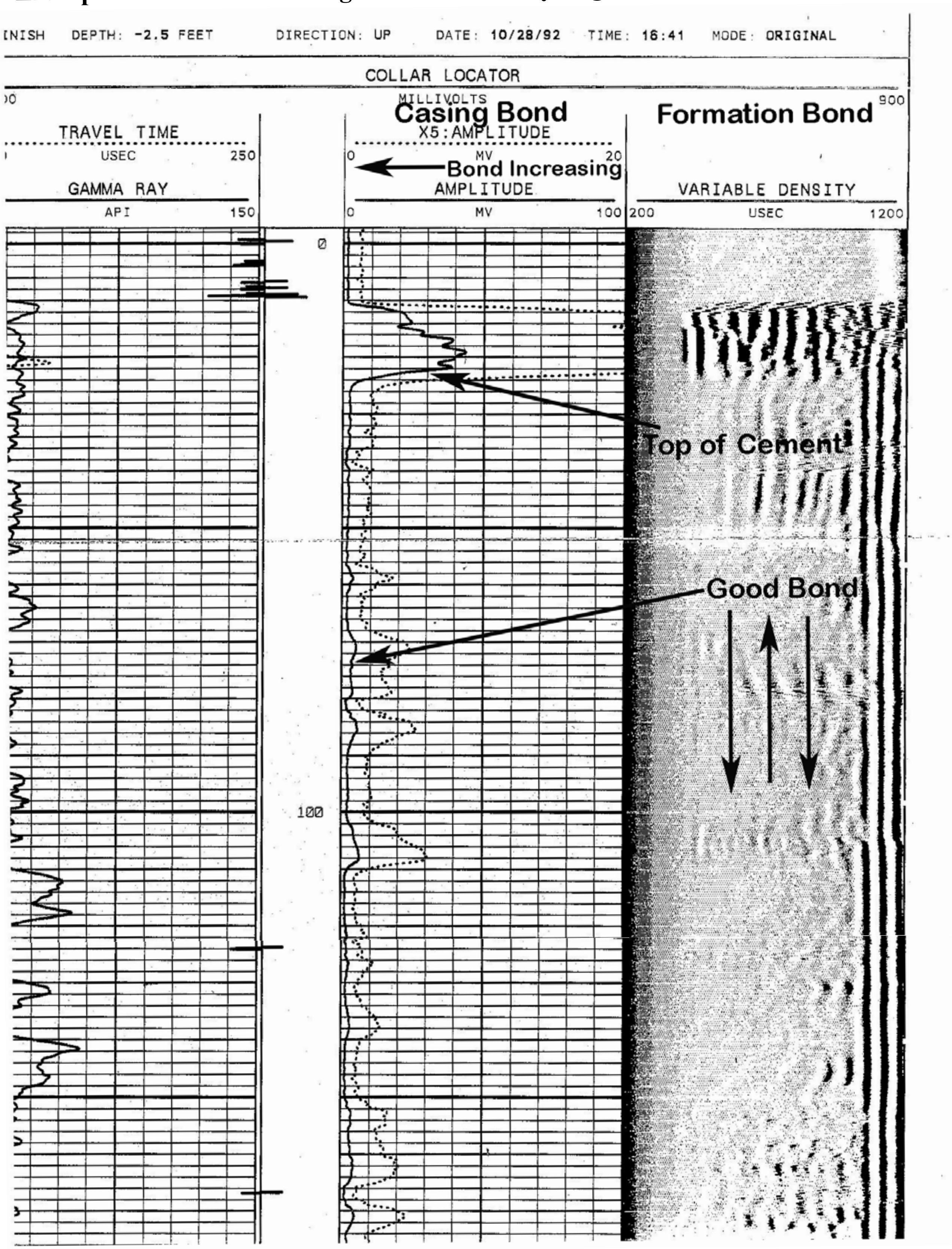
C. The Companies and EPA may, upon unanimous consent of the signatories, include additional provisions in, or make modifications to, this MOA. Such additions or modifications must contribute to the goal of preventing the endangerment of USDWs. Nothing herein shall be construed as requiring the
adoption of any such additional provisions or modifications.

V. DISPUTE RESOLUTION AND TERMINATION OF AGREEMENT

A. Any Company or EPA may terminate its participation in this MOA by providing written notice to the other signatories. Such termination as to that Company (or, if EPA terminates the MOA, as to all) will be effective 30 days after the receipt of written notice and will result in no penalties or continuing obligations by the terminating Company (or, if EPA terminates the MOA, any signatory). If EPA or any Company terminates the MOA, EPA and/or that Company will refrain from representing that the Company is continuing to cooperate with EPA on replacing diesel fuel in hydraulic fracturing fluids injected in USDWs for CBM production, provided that they may continue to make reference to activities undertaken
through the date of this termination. If its participation in this MOA is terminated by any Company, the MOA shall have no further force and effect for the terminating Company, and the terminating Company shall have no further obligation under the MOA.

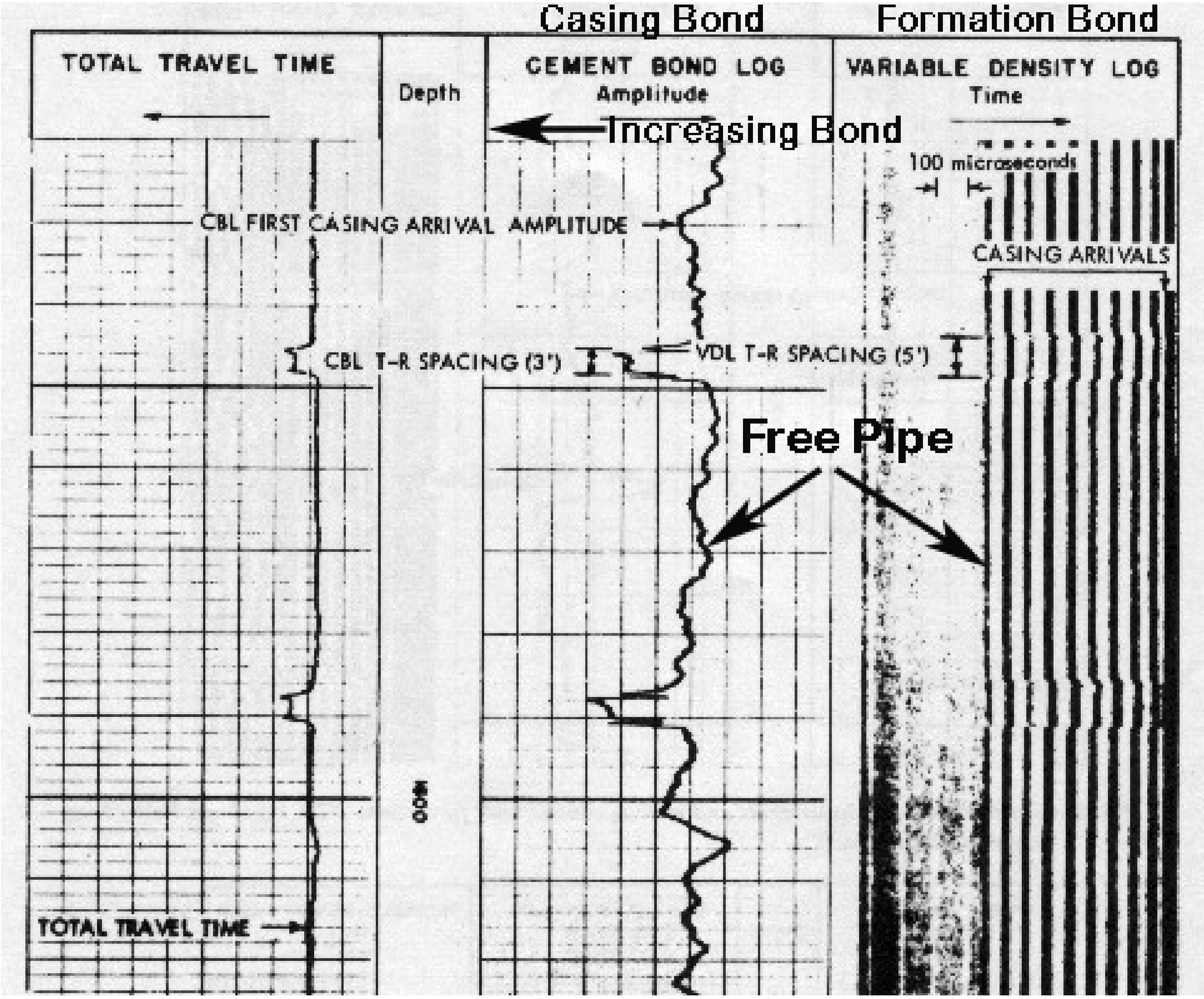
Appendix 5

Example of Cement Bond Log/ Variable Density Log Showing Good Cement Bond



Appendix 6

Example of Cement Bond Log/ Variable Density Log Showing No Cement Bond/ Free Pipe



Appendix 7

MEMORANDUM OF AGREEMENT
BETWEEN THE
INDIANA DEPARTMENT OF NATURAL RESOURCES
AND THE
INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Purpose and Intent

1) This Memorandum of Agreement (MOA) establishes policies, responsibilities, and procedures pursuant to statutes and rules with respect to a regulatory program regarding notification for and cleanup of spills related to petroleum exploration and production activities.

2) This agreement is entered into by the Indiana Department of Natural Resources and signed by the Director of the Department of Natural Resources (Director) with the Indiana Department of Environmental Management and signed by the Commissioner of the Department of Environmental Management (Commissioner).

3) This agreement shall become effective when approved by the Director and Commissioner.

Agency Authorities

4) The Indiana Department of Natural Resources, Division of Oil and Gas (Division) has authority over spills of crude oil, crude oil tank bottoms and saltwater related to petroleum exploration and production activities. The Indiana Department of Environmental Management (IDEM) Office of Environmental Response is responsible for and has authority over spills of any substance into the environment.

5) Nothing in this agreement is intended to affect any programs related to the environment that are not directly under the authority of the Division.

Agency Responsibilities

6) The Division shall respond to all spills of oil and saltwater from the operation and maintenance of tanks, pipes, pumps, valves, and wells related to oil and gas exploration and production and shall have responsibility for spills that meet the following criteria:

- Spills contained within the boundaries of an approved secondary containment structure regardless of volume; or
- Spills not contained within the secondary containment structure if the spill volume is less than 1000 gallons and does not threaten to enter ditches, creeks, ponds or other waters of

Appendix 7 *continued*

the state

- Spills of oil when less than 55 gallons leave the facility boundary.

7) The IDEM shall be responsible for spills of oil and saltwater from the operation and maintenance of tanks, pipes, pumps, valves, and wells related to oil and gas exploration and production that meet the following criteria:

- Spills not contained within the secondary containment structure if the spill volume is greater than 1000 gallons; or
- Spills that enter or threaten to enter ditches, creeks, ponds, or other waters of the state regardless of volume.
- Spills of oil when greater than 55 gallons leave the facility boundary
- Spills when threats to public health are actual or imminent.
- Spills that are not contained and free material not removed within the time specified in the working agreement.

1) The Indiana Department of Environmental Management is also responsible for any spills not specifically covered by the program to be implemented under the terms of this MOA.

2) The Division shall implement a program related to spills of crude oil, crude oil tank bottoms, and saltwater resulting from petroleum exploration and production that requires an owner or operator to contain, remediate, reuse, remove and treat, or dispose of spills and spill contaminated materials in accordance with promulgated rules, policies, and best management practices.

3) The Division shall promulgate rules that are based on a review of similar regulatory programs in other oil and gas producing states. These rules shall include provisions concerning spill containment, cleanup standards, bioremediation, excavation and disposal, and site remediation.

4) The agency deemed to have responsibility for a spill shall be the lead agency. The lead agency shall provide the on scene coordinator and shall be responsible for the notification and coordination of all state and local agencies involved in the spill.

Communication

5) The parties agree to maintain a level of cooperation and coordination to assure the successful and effective administration of a spill notification and cleanup program. This shall include appropriate and timely contact between the Division and the IDEM. To facilitate this line of communication the Division and the IDEM shall develop a system for reporting, evaluating, and responding to spills.

Appendix 7 *continued*

6) The IDEM is responsible for keeping the IDNR apprised of the meaning and content of statutes, rules, technical standards, policy decisions, directives, and any other factors which may affect this agreement or the program. The IDNR shall promptly inform IDEM of any resource allocation changes such as budget or equipment, any proposed, pending, or enacted modifications to statutes, rules or guidelines, and any judicial decisions or administrative actions which the IDNR believes might affect the Divisions ability to administer the program.

7) The strategies and priorities for implementation of the program shall be established by this agreement. If requested by either party, meetings will be scheduled at reasonable intervals between the Division and the IDEM to review specific operating procedures, resolve problems, or discuss mutual concerns involving the administration of the program.

1) Disputes arising out of the implementation of this agreement shall be resolved through negotiation between the Division and the IDEM. The process of dispute resolution shall be initiated via referral from the Division Inspector and ERS Responder to the next higher level of authority within their respective agencies. The Director of the Division of Oil and Gas and the Emergency Response Branch Chief of the IDEM shall be the final authorities for dispute resolution.

Conformance with Laws and Rules

2) The Division and IDEM shall administer a spill notification and remediation program consistent with the intent of IC 14, IC 13, promulgated rules, this MOA, and any separate working agreements which may be entered into between the Director or his/her designee (IDNR) and the Commissioner and his/her designee (IDEM) as necessary for the full administration of the program. This program shall also specifically conform to the intent of 327 IAC 2-6.1.

Duration of MOA

3) This agreement will remain in effect until such time as either of the parties determines that the program implemented under this agreement is no longer functioning in the manner intended, is not operating in the best interests of the citizens of Indiana, is not protective of the environment, or is no longer authorized or funded.

Enforcement

4) When this agreement has been fully implemented the IDEM will consult with the Division before taking enforcement actions related to spills that are deemed the responsibility of the Division under this agreement. Every effort shall be made to obtain consensus between the agencies with respect to enforcement actions. This paragraph is intended to provide for timely, coordinated, and non duplicative enforcement.

Appendix 7 *continued*

Review and Modifications

5) This agreement and any working agreements shall be reviewed annually by the Indiana Department of Environmental Management and the Division to determine its adequacy and legality. This agreement may be modified upon the initiative of either agency. Modifications must be in writing and must be signed by the Director and Commissioner. Modifications become effective when signed by both the Director and Commissioner. Modifications may be made by revision prior to the effective date of this agreement or subsequently by addenda attached to this agreement and consecutively numbered, signed and dated.

Appendix 8

List of state oil & gas contacts by state for the 27 study states

State	Contact Name	Contact E-mail or phone
Alabama	Butch Gregory	bgregory@ogb.state.al.us
Alaska	General E-mail	aogcc.customer.svc@alaska.gov
Arkansas	Lawrence Bengal	larry.bengal@aogc.state.ar.us
California	General E-mail	DOGGR_Headquarters@conservation.ca.gov
Colorado	General E-mail	Dnr.cogcc@co.us
Florida	General phone	850-488-8217
Illinois	Doug Shutt	doug.shutt@illinois.gov
Indiana	Herschel McDivitt	hmcdivitt@dnr.in.gov
Kansas	Ryan Hoffman	r.hoffman@kcc.ks.gov
Kentucky	Kim Collings	kim.collings@ky.gov
Louisiana	Jim Welsh	Jim.welsh@la.gov
Michigan	Hal Fitch	fitch@michigan.gov
Mississippi	Lisa Ivshin	livshin@ogb.state.ms.us
Montana	Tom Richmond	trichmond@mt.gov
Nebraska	General phone	308-254-6919
New Mexico	Scott Dawson	scott.dawson@state.nm.us
New York	General E-mail	dmnog@gw.dec.state.ny.us
North Dakota	General E-mail	oilandgasinfo@nd.gov
Ohio	Rick Simmers	Rick.simmers@dnr.state.oh.us
Oklahoma	Ron Dunkin	r.dunkin@occemail.com
Pennsylvania	General E-mail	www.depweb.state.pa.us
South Dakota	Derric Iles	Derric.iles@usd.edu
Texas	Leslie Savage	Leslie.savage@rrc.state.tx.us
Utah	John Baza	Johnbaza@utah.gov
Virginia	General phone	276-415-9700
West Virginia	James Martin	James.a.martin@wv.gov
Wyoming	General phone	307-234-7147

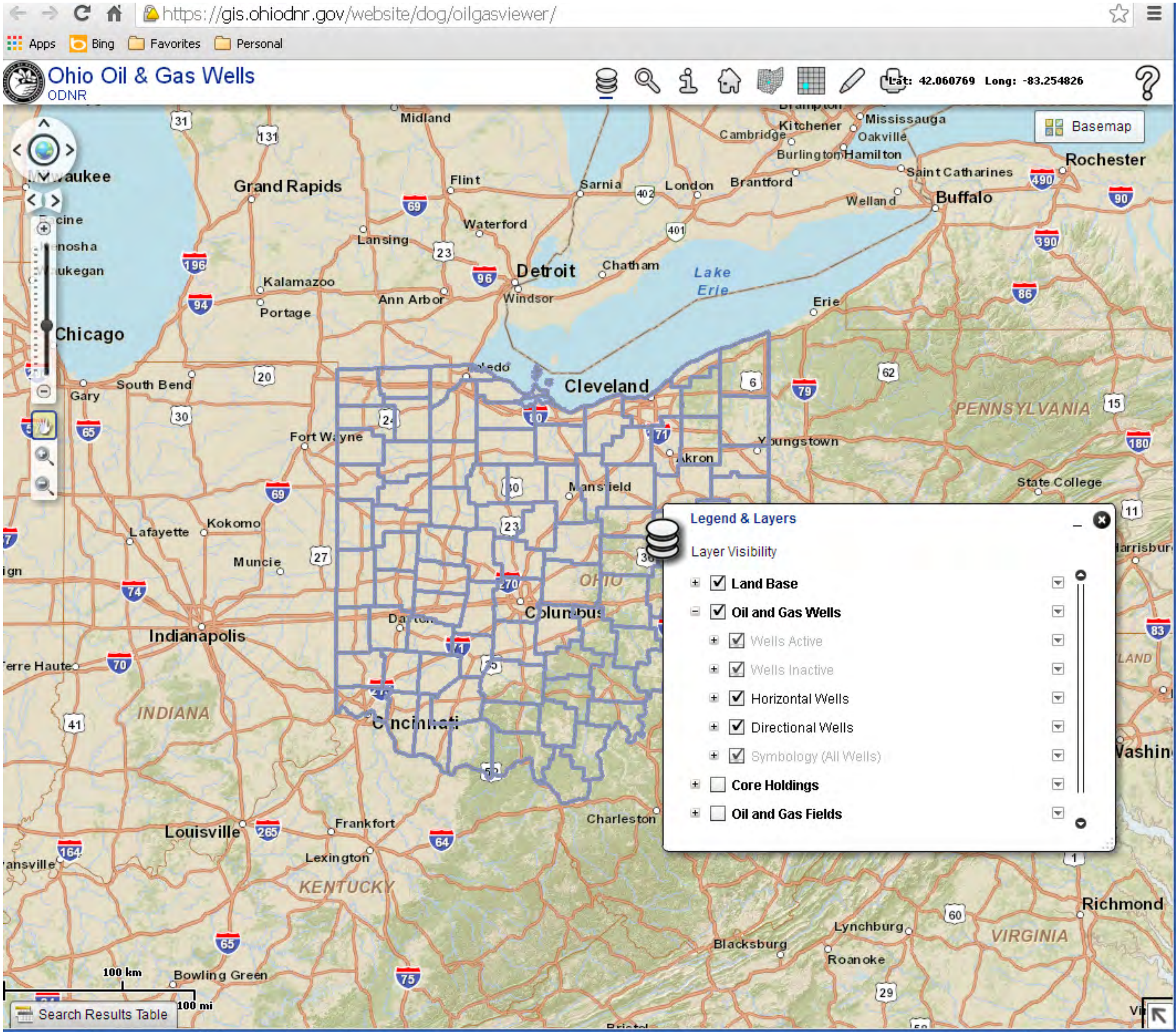
Appendix 9

Hyperlinked list of state regulations websites for the 27 study states

State	Contact E-mail or phone
Alabama	http://www.ogb.state.al.us/documents/misc_ogb/goldbook.pdf
Alaska	http://www.doa.alaska.gov/ogc/Regulations/RegIndex.html
Arkansas	http://www.aogc.state.ar.us/OnlineData/Forms/Rules%20and%20Regulations.pdf
California	http://www.consrv.ca.gov/dog/pubs_stats/Pages/law_regulations.aspx
Colorado	http://cogcc.state.co.us/
Florida	http://www.dep.state.fl.us/water/rulesprog.htm#oil_gas
Illinois	http://www.dnr.illinois.gov/adrules/documents/62-240.pdf
Indiana	http://www.in.gov/dnr/dnroil/2609.htm
Kansas	http://www.kcc.state.ks.us/regs/index.htm
Kentucky	http://www.lrc.ky.gov/kar/TITLE805.htm
Louisiana	http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=62&pnid=0&nid=37
Michigan	http://www.michigan.gov/documents/deq/ogs-oilandgas-regs_263032_7.pdf
Mississippi	http://www.ogb.state.ms.us/docs/20130320.RULEBOOK.pdf
Montana	http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=36.22
Nebraska	http://www.nogcc.ne.gov/NOGCCrulesstatutesindex.aspx
New Mexico	http://www.emnrd.state.nm.us/OCD/documents/SearchablePDFofOCDTitle19Chapter15created3-2-2012.pdf
New York	http://www.dec.ny.gov/energy/1630.html
North Dakota	https://www.dmr.nd.gov/oilgas/rules/rulebook.pdf
Ohio	http://oilandgas.ohiodnr.gov/laws-regulations/oil-gas-law-summary
Oklahoma	http://www.occeweb.com/rules/rulestxt.htm
Pennsylvania	http://www.portal.state.pa.us/portal/server.pt/community/laws%2C_regulations___guidelines/20306
South Dakota	http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=74:12
Texas	http://www.rrc.state.tx.us/rules/rule.php
Utah	http://oilgas.ogm.utah.gov/Rules/Rules.htm
Virginia	http://leg1.state.va.us/000/reg/TOC04025.HTM#C0150
West Virginia	http://www.dep.wv.gov/oil-and-gas/Resources/Regulations/Pages/default.aspx
Wyoming	http://wogcc.state.wy.us/rules-statutes.cfm?Skip='Y'

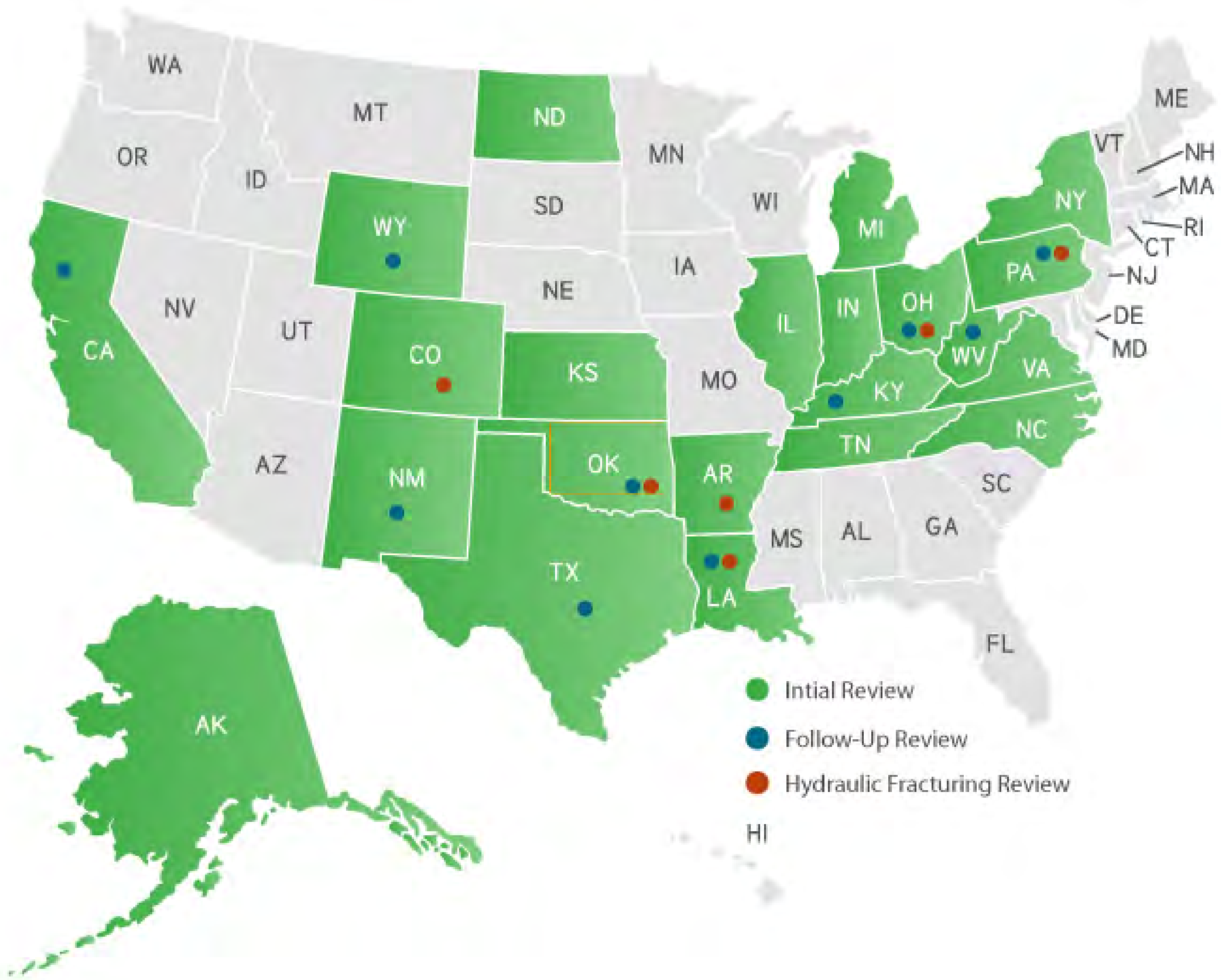
Appendix 10

Ohio DMMR On-line Well GIS Interface



Appendix 11

Map of states with a STRONGER review
(From STRONGER, Inc. website)



Appendix 12

Key Messages and Suggested Actions from 2009 Report

Key Message 1: Claims that the oil and gas E&P industry in the U.S. is unregulated are not supported by the findings of this report. We believe enactment of national regulations on oil and gas exploration and production would be costly to the states, duplicative of state regulation, and ultimately ineffective because such regulations would be too far removed from field operations. Current state regulation of oil and gas activities is environmentally proactive and preventive. All oil and gas producing states have regulations which are designed to provide protection for water resources such as those governing the authorization for drilling, completion, operation and closure of wells. Most state oil and gas agencies also have requirements on the management of fluid handling facilities and spills.

The content and specificity of regulation varies somewhat from state to state. While some states may have detailed regulations in an area such as pits, another state may have more generalized requirements. The reasons for these variations are related to factors such as geography, geology, climate, publicly perceived needs, and age, amount and type of production. For example, states with a principal focus on non coalbed methane gas production may have fewer regulations governing pits unrelated to drilling. This would be expected since; in general, conventional gas production tends to result in smaller amounts of co-produced water than coalbed methane production. Consequently, there is less need for complex or detailed pit construction requirements for pits unrelated to drilling. It should be noted that recent development in shale gas reservoirs throughout the U.S. has resulted in the use of formation treatment practices such as fracturing that are now returning large amounts of fluids to the surface. Consequently, regulations in some states with this recent activity may not yet reflect this with respect to surface storage and management of treatment fluids.

It is very important to note that many of the items listed in the Suggested Action 1 are already properly addressed in a number of state oil and gas regulatory programs. Therefore, the inclusion of an item on the following list of suggested actions is not intended to show that a particular program or specific state lacks the authority or capability to protect water resources through the application of its existing regulations. The purpose of the list is to provide states with an evaluation tool which may be used to assess current regulations and determine if a need exists for updates or revisions.

Suggested Action 1: While current state oil and gas regulations provide multiple mechanisms to protect water resources, there may be regulatory areas which could be reviewed and upgraded if needed including:

Appendix 12 *continued*

- Casing and cement: The following specifications should be considered:

    - Construction materials and methods meeting a specific industry standard such as the API RP-65;
    - Surface casing set to a sufficient depth below the deepest groundwater or USDW; whichever is more appropriate in a given state;
    - Cement circulated to the surface on the outside of surface casing or cement circulated on the intermediate or production casing string into at least the next larger cemented casing string (e.g. from production casing to intermediate casing or intermediate casing into surface casing etc…);
    - Production casing required and set with an amount of cement sufficient to prevent the upward migration of fluids under all reservoir conditions;
    - Centralizers used at appropriate intervals to assure that a cement sheath surrounds the casing strings;
    - Prior notice of casing and cementing operations to regulatory agencies to provide them with an opportunity to witness well construction and, in the absence of witnessing, the submittal of appropriate proof of proper casing and cementing records

- Temporary Abandonment (TA): For wells that are placed on TA status in locations where bottom hole pressure is sufficient to raise fluid levels to a height which could intersect a groundwater zone or USDW, or in fields where enhanced recovery is being used, the following requirements should be considered:

    - casing integrity demonstrations; including the placement of bridge plugs, when necessary, to prevent groundwater contamination; or
    - assurance that static fluid levels in the well are below groundwater zones

- Plugging: Materials and methods used in plugging should be limited to those that, through an appropriate verification or certification process, are deemed effective in maintaining the long term ability of a well or wellbore to prevent the upward migration of fluids. The use of non standard plugging materials and methods such as "brush plugs", "bentonite clay" and "bullhead plugging" should be carefully assessed before being allowed. Unless a bridge plug is used as the base for plugging or a well is plugged from the bottom of the hole, the tagging of plugs should be considered to demonstrate that unsupported cement plugs remain where they were placed.

- Tanks: Tank materials and construction methods should meet an appropriate industry or technical standard and tanks should be maintained in a manner that prevents leakage. In the absence of an adopted industry standard, the materials required in tank construction

Appendix 12 *continued*

should be suitable for their usage as determined by the appropriate state agency. For example, the use of tanks that are made of non corrosion resistant steel should not be used for the storage of produced water since many oil and gas brines are corrosive in nature. The use of well constructed containment dikes surrounding tank batteries, where needed to prevent water contamination, should be considered. Further, containment dikes should meet a permeability standard, as demonstrated by testing methods such as a percolation rate test, or a holding time standard. There should be a requirement that areas inside the dike be kept free of fluids unless a release from a tank has occurred or after rainfall events so they will serve the purpose for which they were constructed. Regulations should specify how long releases or other fluids inside a containment dike should be allowed to remain before removal.

- Pits: Pits used for long term storage of produced fluids or other RCRA exempt waste should be required to utilize a natural or artificial liner, where needed to protect groundwater. Liners should meet specific permeability and construction standards designed to prevent downward migration of fluids into groundwater. Pits should not be excavated to a depth that exceeds the seasonal high water table or used in areas where the underlying bedrock contains seepage routes, solution features or springs. Pits used for long term storage of produced fluids or other RCRA exempt waste should not be allowed within the boundaries of a designated 100 year flood event without implementation of construction requirements designed to prevent ingress and egress of fluids during a flood. Pits designated as evaporation pits should not be allowed in regions where average annual precipitation exceeds average annual evaporation and all evaporation pits should be lined as noted above to prevent downward migration of fluids. States should consider prohibiting the use of pits within the boundaries of public water supply and wellhead protection areas. Pit closure specifications including the disposition of fluids and solids in the pit and the disposal of pit liners should be implemented.

- Spill Remediation: Operators should be required to remediate soils affected by oil and saltwater spills to a specific cleanup standard such as a Total Petroleum Hydrocarbon (TPH) level for oil affected soil and a Sodium Absorption Ratio (SAR) for salt affected soil. The table used by Colorado; shown at the end of Chapter 5, provides an example of the type of cleanup standard that can be applied by a regulatory agency.

- Surface Discharge: The discharge of drilling or RCRA exempt E&P waste fluids at the surface should not occur without the issuance of a state NPDES permit if the discharge could enter water, or similar permit or an authorization administered by the oil and gas agency if the discharge could not enter water.

Appendix 12 *continued*

Key Message 2: Historically, some E&P activities have caused contamination of both surface and groundwater. Past practices related to pit construction, well cementing and operation, and well plugging were not always adequate to prevent migration of contaminants to surface and groundwater. However, the development and application of new regulations over the past twenty to twenty-five years has provided a more effective means for protecting water resources from various oil and gas E&P activities.

For example, the implementation of requirements for pit liners in many states has resulted in increased protection of shallow groundwater by preventing leaching of contaminants into the subsurface. Similarly, upgraded requirements for surface casing and cement have created better protection for groundwater formations from the intrusion of fluids from deeper zones and from well completion and treatment operations. In fact, based on over sixty years of practical application and a lack of evidence to the contrary, there is nothing to indicate that when coupled with appropriate well construction; the practice of hydraulic fracturing in deep formations endangers groundwater. There is also a lack of demonstrated evidence that hydraulic fracturing conducted in many shallower formations presents a substantial risk of endangerment to groundwater.

Suggested Action 2a: Comprehensive studies should be undertaken to determine the relative risk to water resources from the practice of shallow hydraulic fracturing. The studies should focus on evaluating both the theoretical and empirical relationship of hydraulic fracturing to groundwater protection. In conjunction with the knowledge of current practices, these studies should be used to develop a generic set of BMPs for the practice of hydraulic fracturing from which state agencies may as appropriate:

- develop their own state specific BMPs;
- develop additional state regulations relative to the practice

Suggested Action 2b: State and federal agencies should remain cautious about developing and implementing regulations based on anecdotal evidence alone. Nevertheless, complaints of groundwater contamination attributed to hydraulic fracturing should continue to be investigated by the appropriate state agency to determine whether or not groundwater has been affected and whether a causal relationship can be established between any impacts to groundwater and the implementation of hydraulic fracturing. Within this context, states should consider requiring companies to submit a list of additives used in formation fracturing and their concentration within the fracture fluid matrix. Further, states that do not currently regulate handling and disposal of fracture fluid additives and constituents recovered during recycling operations should consider the need to develop such regulations.

Appendix 12 *continued*

Suggested Action 2c: When a formation to be fractured is in close proximity to a USDW, as determined by the regulatory agency using state and site specific criteria, an appropriate cement evaluation tool such as, at a minimum, a cement bond log coupled with a variable density log (CBL/ VDL, See Appendices 5 and 6) should be run on the well before hydraulic fracturing occurs. These logs should be interpreted by a qualified person in the regulatory agency to determine if adequate cement to casing and cement to formation bond exists over a sufficient wellbore interval to prevent the upward migration of fluids within the casing/ formation annulus. In cases where the bond is questionable, remedial cementing followed by re-verification of cement quality should be conducted prior to conducting hydraulic fracturing.

Suggested Action 2d: Hydraulic fracturing in oil or gas bearing zones that occur in non-exempt USDW's should be either stopped, or restricted to the use of materials that do not pose a risk of endangering groundwater and do not have the potential to cause human health effects (e.g., fresh water, sand, etc.)

Key Message 3: Many states split jurisdiction between oil and gas and water quality or pollution control agencies over some aspects of oil and gas regulation including tanks, pits, waste handling and spills. Some oil and gas programs reside within an agency that also houses other state environmental programs. However, most are separate entities that may not have regulatory systems which are formally coordinated. The lack or formal coordination between state agencies can sometimes result in a case of jurisdictional confusion under which the management of environmental issues could be delayed.

Suggested Action 3: Where split jurisdiction of oil and gas operations exists, formal memorandums of agreement and regulatory implementation plans should be negotiated between state agencies with jurisdiction over parts of oil and gas operations so that coordination of effort can be achieved. Regular review and updating of these documents should also be undertaken to reflect jurisdictional changes and newly identified coordination issues.

Key Message 4: The state review process managed by STRONGER, Inc. is an effective tool for ensuring that state environmental regulatory programs related to the management of E&P waste are conducted in a manner that is protective of the environment. The success of the STRONGER process in promoting changes to state programs through its reviews and recommendations has resulted in an overall net increase in environmental protection for water resources and demonstrated that state regulation is a very effective means of managing E&P wastes.

Suggested Action 4a: The RCRA Subtitle C exemption for E&P wastes should be retained and E&P waste regulation should continue to be managed primarily at the state level.

Appendix 12 *continued*

Suggested Action 4b: STRONGER should continue its efforts to obtain volunteer states for initial review, conduct follow-up reviews to evaluate state response to initial review recommendations and revise its guidelines, as necessary, to stay current with respect to regulatory and technological advances.

Suggested Action 4c: STRONGER should evaluate whether to update its mission to include environmental elements of state oil and gas programs beyond the traditional area of E&P waste.

Key Message 5: The implementation and advancement of data management systems provides regulatory agencies with increasing capacity to track compliance, facilitate field inspections, and prepare reports that can be used to evaluate the effectiveness of state oil and gas regulations implementation. The exponential growth in data management capabilities, systems functionality and ease of use and access over the past several years has enhanced the ability of state agencies to more effectively manage the information they receive. However, there is still a need to convert paper records to electronic formats and to more fully integrate environmental data in a form that is accessible and easily understood.

Suggested Action 5: State oil and gas and other water protection agencies should continue to expand their data management capabilities and, within the confines of available funding, implement the latest technologies for electronically acquiring, storing, sharing, extracting and utilizing environmental data. The federal government should provide financial support to the state agencies efforts to hasten the pace of systems implementation and resulting data availability.

Appendix 13

Review of Activities Related to Key Messages and Suggested Actions from 2009

Suggestion One: Regulations

The 2009 Report made many suggestions for regulatory action, some of which will be repeated again in this 2013 report, as further improvement in these areas remains necessary. The originally offered recommendations were not comprehensively reviewed against adopted and proposed rules since 2009; however, in an effort to recognize progress, this section includes a few examples of trends in rulemaking that addressed some significant recommendations.

Select Suggestions Regarding Casing & Cement

- Suggestion: Construction materials and methods meet a specific industry standard such as API RP-65
    - In 2009: Five states required casing to meet API standards; four states required cement to meet API standards
    - By 2013: Two additional states required casing to meet API standards; four additional states required cement to meet API standards; two states have proposals regarding casing and cement standards
- Suggestion: Cement circulated to the surface on the outside of surface casing or cement circulated on the intermediate or production casing string into at least the next largest cemented casing string (*e.g.*, from production casing to intermediate casing or intermediate casing into surface casing, etc.)
    - In 2009: Twenty-six states required surface casing cement from bottom to the top; four states required intermediate casing cement from bottom to top, and five states required intermediate casing cement from bottom to next cemented string; six states required production casing cement from bottom to top, and six states required production casing cement from bottom to next cemented string
    - By 2013: One additional state required surface casing cement from bottom to top; five additional states required intermediate casing cement from bottom to top, and four additional states required intermediate casing cement from bottom to next cemented string; no additional states made changes to rules for production casing; two states have proposals pending regarding cement circulation

Select Suggestions Regarding Plugging

- Suggestion: Use of non-standard plugging materials and methods such as “brush plugs,” “Bentonite clay,” and “bullhead plugging” carefully assessed before being allowed

Appendix 13 *continued*

- In 2009: Ten states allowed materials other than cement
- By 2013: Eleven states allowed materials other than cement *when consistent with performance objectives*, and 24 states specifically allowed bullhead plugging

Select Suggestions Regarding Tanks

- Suggestion: containment dikes surrounding tank batteries
  - In 2009: Twenty-two states required secondary containment
  - By 2013: One additional state required secondary containment; two states have proposals requiring secondary containment
- Suggestion: Areas inside dike kept free of fluids unless a release has occurred or after rainfall events
  - In 2009: Thirteen states prohibited standing fluids in containment areas
  - By 2013: Three additional states prohibited standing fluids in containment areas; one state has a proposal on the subject

Select Suggestions Regarding Pits

- Suggestion: Liners meet specific permeability and construction standards designed to prevent downward migration of fluids into groundwater
  - In 2009: Fifteen states specified competency standards for artificial lining
  - By 2013: Seven additional states specified competency standards for artificial lining; one state has a proposal regarding competency standards

Select Suggestions Regarding Spill Remediation

- Suggestion: Operators required to remediate soils affected by oil and saltwater spills to a specific cleanup standard such as Total Petroleum Hydrocarbon (TPH) level for oil affected soil and Sodium Absorption Ratio (SAR) for salt affected soil
  - In 2009: Twelve states specified cleanup standards
  - By 2013: One additional state specified cleanup standards; three states have proposed cleanup standards

Select Suggestions Regarding Surface Discharge

- Suggestion: No discharge of drilling or RCRA-exempt waste fluids at surface without permit or authorization if discharge could not enter water
  - In 2009: Twenty-three states regulated onsite disposal of waste; 18 states regulated the application of salt water to roads/lands; ten states required chain of custody for off site disposal

Appendix 13 *continued*

- By 2013: No additional states added regulations regarding on-site disposal; two states added regulations regarding the application of salt water to roads; and nine states required manifests for offsite disposal (note: this matrix question changed slightly from its counterpart in 2009 regarding chain of custody, so the two numbers are not directly comparable); two states have proposed rules regarding waste disposal

Suggested Action 2a: Comprehensive studies should be undertaken to determine the relative risk to water resources from the practice of shallow hydraulic fracturing. The studies should focus on evaluating both the theoretical and empirical relationship of hydraulic fracturing to groundwater protection. In conjunction with the knowledge of current practices, these studies should be used to develop a generic set of BMPs for the practice of hydraulic fracturing from which state agencies may as appropriate:

- develop their own state specific BMPs;
- develop additional state regulations relative to the practice

Activity related to suggested action 2a since 2009: The American Petroleum Institute developed a hydraulic fracturing recommended practice. This practice, titled "HF1 –Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines", 1st Edition, October 2009, (API) contains:

- Industry practices for well construction and integrity for wells that will be hydraulically fractured
- Guidance identifying actions to protect shallow groundwater aquifers, while also enabling economically viable development of oil and natural gas resources

Suggested Action 2b: State and federal agencies should remain cautious about developing and implementing regulations based on anecdotal evidence alone. Nevertheless, complaints of groundwater contamination attributed to hydraulic fracturing should continue to be investigated by the appropriate state agency to determine whether or not groundwater has been affected and whether a causal relationship can be established between any impacts to groundwater and the implementation of hydraulic fracturing. Within this context, states should consider requiring companies to submit a list of additives used in formation fracturing and their concentration within the fracture fluid matrix. Further, states that do not currently regulate handling and disposal of fracture fluid additives and constituents recovered during recycling operations should consider the need to develop such regulations.

Appendix 13 *continued*

Activity related to suggested action 2b since 2009: Several states have updated their regulations related to the practice of well treatment, treatment reporting, well construction, etc. While some of these updates were prompted by public concerns, the actual regulations developed were based on technical and scientific principals and standard management practices. For example, Ohio updated its well construction requirements under a process that involved publicly held meetings of a workgroup that included technical, environmental, industry and regulatory personnel and took into account the latest advancements in well construction technology. The regulation also incorporated of elements of the Model Regulatory Framework, developed by Southwestern Energy and the Environmental Defense Fund.

Suggested Action 2c: When a formation to be fractured is in close proximity to a USDW, as determined by the regulatory agency using state and site specific criteria, an appropriate cement evaluation tool such as, at a minimum, a cement bond log coupled with a variable density log (CBL/ VDL, See Appendices 5 and 6) should be run on the well before hydraulic fracturing occurs. These logs should be interpreted by a qualified person in the regulatory agency to determine if adequate cement to casing and cement to formation bond exists over a sufficient wellbore interval to prevent the upward migration of fluids within the casing/ formation annulus. In cases where the bond is questionable, remedial cementing followed by re-verification of cement quality should be conducted prior to conducting hydraulic fracturing.

Activity related to suggested action 2c since 2009: Seven states have promulgated regulations that require a wellbore mechanical integrity test before commencement of fracturing or re-fracturing. In addition, eight states require the monitoring and recording of stimulation operations throughout the stimulation process. Finally, four states now specifically require fracturing fluid to be confined to the target reservoir.

Suggested Action 2d: Hydraulic fracturing in oil or gas bearing zones that occur in non-exempt USDW's should be either stopped, or restricted to the use of materials that do not pose a risk of endangering groundwater and do not have the potential to cause human health effects (e.g., fresh water, sand, etc.)

Activity related to suggested action 2d since 2009: No specific updates to state regulations in these areas were found.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist, and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Appendix 14

Example FracFocus 2.0 Disclosure Record

Job Start Date:	11/24/2012
Job End Date:	11/28/2012
State:	Colorado
County:	Garfield
API Number:	05-045-99999-00-00
Operator Name:	Test Oil and Gas Company
Well Name and Number:	Test well #1
Longitude:	-108.15661000
Latitude:	39.68376000
Datum:	NAD27
Federal Well:	YES
Total Base Water Volume (gal):	12,335,694
Total Base Non Water Volume:	

Frac Focus
Chemical Disclosure Registry
GROUNDWATER PROTECTION COUNCIL
Oil & Gas

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water	Encana	Base Fluid					
			Water	7732-18-5	1.00	99.92899	Recycled
Sodium Hypochlorite	Baker Hughes, Inc.	Biocide					
			Water	7732-18-5	0.76	0.00967	
			Sodium chloride	7647-14-5	0.30	0.00382	
			Sodium hypochlorite	7681-52-9	0.30	0.00382	
ALPHA 1427	Baker Petrolite	Biocide					
			Glutaraldehyde	111-30-8	0.30	0.00784	
			Didecyl dimethyl ammonium chloride	7173-51-5	0.10	0.00261	
			Quaternary ammonium compound	68424-85-1	0.05	0.00131	
			Ethanol	64-17-5	0.05	0.00131	
ASPEN FR-27	Aspen Polymers	Friction Reducer					
			Ethylene glycol	107-21-1	0.03	0.00096	
BioBalls	Santrol Proppants	Fluid Diverter					
			Polylactide Resin	9051-89-2	1.00	0.00000	% Trade Secret
Ingredients shown above are subject to 29 CFR 1910.1200(i) and appear on Material Safety Data Sheets (MSDS). Ingredients shown below are Non-MSDS.							
Other Chemicals	Other Chemicals	Other Chemicals					
			Sorbitan Monooleate	1338-43-8	0.00	0.00000	
			2-Propenoic acid, polymer with 2-propenamide, sodium salt	25987-30-8	0.00	0.00000	
			Isoparaffinic Solvent	64742-47-8	0.00	0.00000	
			Water	7732-18-5	0.00	0.00000	
			Ethoxylated Alcohols	66455-15-0	0.00	0.00000	
			Sodium Acetate	127-09-3	0.00	0.00000	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water
** Information is based on the maximum potential for concentration and thus the total may be over 100%

Note: For Field Development Products (products that begin with FDP), MSDS level only information has been provided.
Ingredient information for chemicals subject to 29 CFR 1910.1200(i) and Appendix D are obtained from suppliers Material Safety Data Sheets (MSDS)

Appendix 15

Comparison of Risk Factors for Pits and Tanks

Drilling and produced fluids can be stored in either pits or tanks. Each has advantages and disadvantages when it comes to managing risk, as outlined in the following table.

	Advantage	
Risk Categories	**Pits**	**Tanks**
Shallow groundwater contamination	-	-
Catastrophic failure	X	
Leak detection		X
Maintenance		X
Volume of storage	X	
Protection of wildlife		X
Protection from illegal dumping		X
Protection from acts of vandalism	X	
Loss of contents from flooding	-	-
Fire potential	X	
Confined entry risk	X	
Ease of closure and site remediation	-	-

A relative disadvantage in a storage method can be negated or even changed to an advantage by an additional design or operational component. For example, while pits can store a much larger volume of fluid than tanks on a per-barrel-cost basis, they have a greater potential for shallow groundwater contamination since they may be excavated into the ground and since their larger footprint cannot be visibly inspected, making it difficult to identify leaks quickly. However, a pit with an active leak detection system may have an advantage over a tank or tank battery with no leak detection. An active leak detection system also simplifies pit maintenance since it provides the ability to continually monitor liner integrity without the need for draining of the pit. Conversely, while it is easier to monitor for smaller leaks in tank systems, tanks are more prone to catastrophic failures, which can result in the release of much larger volumes of fluids in a single event. Also, while tanks are easier to maintain due to their accessibility, they typically require more frequent maintenance because of their exposure to the weather, exposure to potential corrosive properties of the material stored, and potential for vandalism.

Determining which fluid storage system to use in a specific circumstance involves an evaluation of the unique aspects of the location, purpose, and usage. In locations where groundwater is deeper and there are natural clay barriers between the surface and subsurface, pits may be a good option for temporary or even long-term storage of produced water and exempt waste.

Appendix 15 *continued*

Conversely, where groundwater is shallow or there are few barriers to downward migration of fluids, tanks may provide a better option for fluid storage. While it might appear that tank systems are the most environmentally protective in all cases, this is not borne out by the evidence. Each fluid storage system has plusses and minuses which makes it important that the decision regarding their use be made on a case by case basis.

Explanations of the tanks versus pits ratings are given below.

<u>Shallow groundwater contamination</u>

Although tanks are set above ground and typically surrounded by containment dikes designed to hold the contents of a spill or leak, they can pose a risk of contamination to shallow groundwater from leaks (especially those on the underside of the tank). Pits can be excavated to depths that are in close proximity to shallow groundwater. The presence of a leak detection system and routine inspection and maintenance will provide a distinct advantage to a storage facility (pit or tank) over a facility without these design and operational components. *Advantage neither*

<u>Catastrophic failure</u>

Pits are less prone to catastrophic failure than tanks. Pit liners can leak and result in migration of fluids from the inside of the pit. However, the complete failure of a pit liner in a manner resulting in a total loss of pit contents is rare. With respect to tanks, while the most common failure involves small leaks, a complete failure of a tank that has not been subject to routine inspection and maintenance is possible. *Advantage pits*

<u>Leak detection</u>

Unless a leak is occurring on the bottom of a tank where it cannot be seen, it is easy to detect leaks in tank systems, including the tanks and associated piping. With respect to leaks from the bottom of tanks, leak detection systems are available, and if inflows and outflows can be accurately determined, routine gauging of the tanks can be used to detect leaks. Further, overfilling of tanks can be managed by automated systems, which are much more difficult to install and use in pits. *Advantage tanks*

<u>Ease of maintenance</u>

In order to fully maintain pits it is necessary to drain their contents and inspect the pit liner, and when necessary, remove and replace liner systems. This is a costly and time-consuming process and involves the need to temporarily store potentially large volumes of fluids from the pit, which can result in the need to place significant numbers of temporary tanks on site for storage. Tanks

Appendix 15 *continued*

require maintenance such as painting, patching, and sometimes replacement, and they also need to be periodically drained and inspected so that any internal deterioration can be identified. However, the accessibility of tanks makes these jobs easier to manage and the smaller volumes of fluids in individual tanks reduce the need for large numbers of temporary tanks whenever draining for inspection and maintenance is required. *Advantage tanks*

<u>Volume of storage</u>

Tanks have a limited storage capacity. In locations where large volumes of fluid are produced or handled, the use of tanks is more difficult and costly due to the number of tanks needed. Pits can easily handle much larger fluid volumes at a more reasonable cost. *Advantage pits*

<u>Protection of wildlife</u>

Although it is common to net and fence pits, this practice can be more difficult if a pit has a large surface area. Closed-top tanks prevent the introduction of wildlife. *Advantage tanks*

<u>Protection from illegal dumping</u>

Closed-top tanks discourage disposal of unauthorized or improper fluids. Pits that are not fenced off from the public provide an inviting location to dump illegal substances. *Advantage tanks*

<u>Protection from acts of vandalism</u>

With their readily accessible valves, flowlines, above-ground profiles, and oftentimes catwalks, tanks are an inviting target for persons bent on mayhem. Tanks can be damaged and their contents readily released by a well-placed sledge hammer strike to a valve. In contrast, pits do not present an inviting target for a vandal. Removing fluids from a pit would be time-consuming and would require that a vandal have access to a high-capacity pump with discharge and intake lines. *Advantage pits*

<u>Loss of contents from flooding</u>

Any structure within the boundaries of a floodplain is susceptible to flooding. While construction details (e.g., the height of the berm of a pit or containment dike of a tank or tank battery) can protect the storage facility from rising water levels, neither pits nor tanks can be expected to withstand flowing flood waters and debris. *Advantage neither*

Appendix 15 *continued*

Fire potential

Both pits and tanks have the potential to be affected by fires. However, flammable surface contents in an open pit can typically be allowed to burn out, posing a low risk of injury or death. In contrast, fires in a tank battery can result in substantial damage from tank explosions and failures of the tank resulting in total loss of tank contents. Further, a tank failure resulting from a fire places all other tanks in a tank battery at risk, multiplying the overall risk. *Advantage pits*

Confined space entry

Pits, by their nature, are open to the air and do not subject individuals to risks associated with confined space entry. Conversely, tanks are closed units that can capture and hold noxious gases. This problem is especially notable where produced fluids contain hydrogen sulfide. *Advantage pits*

Ease of closure and site remediation

Both pits and tanks have unique closure and remediation issues. Pits must be drained and the fluids properly disposed of, liners removed and disposed of or shredded and interred, and the pit backfilled, graded, and sometimes seeded. Tanks must have their contents removed and properly disposed of, the tanks removed, the site leveled and graded, and the soils either removed and properly disposed of or remediated in place. *Advantage neither*

Appendix 16

The History of Oil and Gas Regulation

Prior to 1935: The Early Years

Most early regulations on well construction and plugging were not designed to protect ground and surface water from the impacts of oil and natural gas production. Rather, the principal focus was on protecting the petroleum resource from the effects of water incursion. Early casing and cementing programs of oil and gas wells were practical measures to prevent waters from adjacent non-productive formations and upper aquifers from flooding the oil-producing reservoir during drilling and production, which occasionally occurred in such volume that drillers "lost the hole" before penetrating the target oil horizon. In short, protection activities were incipient oil conservation measures recognizing that flooding out of the oil reservoir created "loss" of a valuable product. The prevailing thinking was illustrated in a 1919 technical book, *Practical Oil Geology*, in which Dorsey Hager states in a chapter entitled "Water: Enemy of the Petroleum Industry," that "The danger of water in oil fields must not be underestimated. Water flooding is a danger often present where care is not taken in advance to protect the wells."

Most oil producers of this period believed that royalty payments to the landowner for the privilege of extracting oil or gas from beneath their land adequately compensated the landowner for any surface and water resource damages caused to the property. These damages included accidental spillage of oil or salt water, leakage of produced water from storage and disposal pits, and loss of agricultural land taken out of production by the occupancy of property by oil-field-related equipment or structures or around the working vicinity of each well. Prior to the 1940s, pollution to groundwater from activities at tank battery locations that rendered fresh water aquifers unusable for a long period of time was not a concept widely understood by the oil industry, landowners, or state regulatory agencies. Even landowners who had experienced considerable damage to their farms first viewed surface pollution as a necessary evil and an inherent part of the oil or gas production process.

From the time the first documented oil well was drilled in Pennsylvania in 1859 by Colonel Drake to the early 1930s, the exploration and production industry generally proceeded without much formal regulation, either at the state or federal level. New York required the plugging of abandoned wells as early as 1879. Ohio reported enacting the first law for regulating methods used to case and plug oil and gas wells to prevent water from penetrating and contaminating the oil bearing rock in 1883. In 1890, Pennsylvania passed the first law requiring non-producing wells to be plugged in order to protect the integrity of the producing formation. In 1915, the Oil and Gas Division of the Oklahoma Corporation Commission (OCC) was given exclusive jurisdiction over all wells drilled for the exploration and production of oil and gas and in 1917,

Appendix 16 *continued*

the OCC was given authority over related groundwater protection and mandated to develop procedures for plugging and abandonment. The Texas Railroad Commission was given similar authorities in 1917 and 1919 respectively. California enacted a plugging program in 1915 and added a groundwater protection component in 1929. Other states set up oil and gas regulatory commissions, often without specific authority to promulgate regulations and where enforcement authority was only available under the general statutes and civil or county control.

The United States was, and still is, the only oil producing country in the world where mineral rights can be privately owned and the owner can enter into a lease agreement with a company to extract hydrocarbons in return for a royalty payment based on a percentage of each barrel produced and sold. By the early 1930s, due to this system of independent leasing, the oil market had sometimes exhibited dramatic misalignments of supply and demand. Around 1931, for example, a barrel of oil, which cost about 80 cents to produce, sold for as low as 15 cents.[53] Faced with the potential for serious gluts of unmarketable oil, several governors -- over the objections of oil producers, some state legislators, and landowners -- felt that some framework of government controls over the production of oil was necessary.

1935-1945: Oil and Gas Conservation Is Born

In 1935, after several aborted attempts to come up with an acceptable concept for government intervention into the supply-demand roller coaster, six states, Oklahoma, Texas, Colorado, Illinois, New Mexico, and Kansas, formed the Interstate Oil Compact Commission (IOCC).[54]

The purpose of the IOCC was to promote conservation of oil resources through an orderly development of oil reservoirs. Companies would predict a market demand for their product and the state agency would then set an annual or semi-annual extraction allowable for each producing field (or producing horizon) based on the market prediction. Governor Marland of Oklahoma supported a concept addressing “economic waste” and believed that government should prorate production to obtain a fair price for crude oil. This concept was eventually changed to embrace the term “physical waste” and the six states ratified the Compact agreement.

One of the early efforts of the Compact was the development of a set of model regulations that the states could use as a pattern to establish their own regulatory framework. Even though the model established a format for oil and gas conservation, the protection of groundwater from pollution was carried as a secondary consideration in most regulations, particularly as the regulations applied to well construction and plugging. In the early 1960s, the IOCC also developed a model for gas regulation similar to that created for oil in 1935.

---

[53] INTERSTATE OIL AND GAS COMPACT COMMISSION, MAKING A DIFFERENCE: A HISTORICAL LOOK AT THE IOGCC (2006), *available at* http://iogcc.publishpath.com/Websites/iogcc/pdfs/2006-FINAL-History-Publication.pdf.
[54] In 1991, the organization changed its name to the Interstate Oil and Gas Compact Commission (IOGCC).

Appendix 16 *continued*

From 1941 through the end of World War II, several state legislatures enacted moratoriums on the enforcement of environmental regulations and conservation practices controlling supply and demand, due to the increased need for oil for the war effort. As a result, in late 1941, the United States had a surplus capacity of about 1 million barrels of oil, approximately 80% of which was produced from Compact states. This experience proved the beneficial effects of conservation and, by 1945, the IOCC had grown in membership to 17 states and was a sustaining force in providing models for oil and gas producing states to follow in promulgating regulations.

1945 to 1970: U.S. Oil Production Dominance

Throughout the period 1946 to 1960, most oil and gas producing states established a regulatory agency to enforce oil and gas conservation practices. Still, the environmental protection aspects of the oil regulatory picture developed sporadically. State statutes regarding pollution abatement and control of oil field practices and waste emanated from individual events rather than from an overall "welfare of the nation" impetus. Kansas, for example, gave its Board of Health (not the Corporation Commission) authority in 1946 to issue orders against oil field brine disposal pits that were causing salt water pollution, but it wasn't until January 1958 that the Board could issue permits for acceptable pit usage and deny permits for those deemed to cause potential pollution. Texas adopted regulations in the late 1960s regarding the use of "evaporation pits" and several other states developed a stricter approach to how long produced fluids could be retained in pit. The concern over pit usage stemmed from a realization that these so-called "produced water evaporation pits" were little more than unsealed seepage pits and, as a result, domestic water wells were being contaminated with salt water.

The Environmental 1970s and 1980s

The 1970s brought the nation's environmental consciousness to the forefront. The passage of the Federal Water Pollution Control Act (FWPCA) in 1972 sent the message that discharges of pollutants to the nation's waterways, estuaries and drainages, even intermittent ones, were no longer acceptable and discharges of specific inorganic pollutants were to be regulated either by state or federal permit. Congress authorized formation of the U.S. Environmental Protection Agency (EPA) to implement the FWPCA and successive environmental and water resource protection acts. Section 311 of the FWPCA and its successor, the Clean Water Act (CWA) of 1977, elevated the consequence of accidental spillage of oil from a producing lease to a finable offense when the oil entered a flowing stream. The non-reporting of an oil spill was also a finable offense.

Another part of the CWA required containment dikes around tank batteries and oil storage facilities to prevent releases of oil to "navigable streams," which by definition included almost every intermittent upper reach of a stream if it connected to a potential flowing watercourse. This

Appendix 16 *continued*

program, called Spill Prevention Control and Countermeasures (SPCC), was administered under the direct implementation authority of EPA. Prior to the FWPCA, most state oil and gas regulatory agencies required operators to contain, report, and clean up serious oil spills on water. However, few operators were fined unless they refused to obey a state agency directive. EPA's enforcement of the SPCC program was sporadic throughout the first 20 years of the FWPCA and CWA and its overall impact on day-to-day oil and gas operations was minor. The CWA, however, marked the first time that the oil and gas producing industry was subject to direct dealings with a federal agency on environmental protection issues.

In 1974, Congress passed the Safe Drinking Water Act (SDWA), which authorized EPA to promulgate regulations for wells used to inject fluids into subsurface formations, including those used for disposal of excess produced water or injection of produced water to increase oil recovery. This section of the SDWA was called the Underground Injection Control (UIC) Program. Between 1982 and 1990, 20 oil producing states applied for and received primary enforcement authority (primacy) from EPA to administer the program under Section 1425 of SDWA. During the same period, 22 states and territories were delegated primacy for Class II wells under Section 1422 of SDWA. Delegation of authority for this program to the states under Section 1425 allowed those with longstanding oil and gas regulatory programs to demonstrate that their programs were equally effective in protecting groundwater as those promulgated and administered by EPA under Section 1422 of SDWA. The major initial impact of the UIC program was that operators had to verify the mechanical integrity of each of their injection wells once every five years. Prior to the UIC program, most regulatory agencies only required operators to test an injection well if it was known or suspected to be leaking.

The 1970s also marked the beginning of the decline in domestic oil production. Some landowners who were actively engaged in agriculture began to view the oil production on their acreage with its declining productivity as a nuisance, rather than a blessing. The state oil and gas regulators received increasing demands from landowners and tenants to have operators plug wells that were idle and appeared to be no longer productive. Many states set up "temporarily abandoned" or "idle" well programs that required operators to monitor the mechanical integrity and certify annually that these idle wells had a future purpose. In the 1980s and particularly after the 1986 depression in the industry, several states (Kansas, Texas, California, and others) received legislative authorization to establish dedicated funding to contract the plugging of abandoned wells. The use of these abandoned or "orphan" well plugging funds resulted in the permanent closure of thousands of wells that might have posed a threat to the environment.

Congress passed the Resource Conservation and Recovery Act (RCRA) in 1976 giving EPA the authority to regulate the disposition and disposal of solid waste with Subtitle C of the Act addressing the determination and management of hazardous waste and Subtitle D the management of non-hazardous waste. The regulatory drivers that led to RCRA include the Solid

Appendix 16 *continued*

Waste Disposal Act of 1965 and amended in 1970, the Water Quality Improvement Act of 1970, and the Resource Recovery Act of 1970. The latter established some of the conceptual framework for RCRA, including using the term "hazardous" separate from the term "solid" waste and the need to identify and dispose of classes of waste. RCRA, which amended the SWDA, set national goals that included protecting human health and the environmental from potential hazards of waste disposal and ensuring that wastes are managed in an environmentally-sound manner.

Fluids produced during E&P of oil and gas were originally excluded from RCRA Subtitle C and set aside for further study. Exemption from RCRA Subtitle C did not preclude these wastes from control under state programs, RCRA Subtitle D, or other federal regulations. In 1988, the EPA Administrator issued a Regulatory Determination that wastes produced in connection with oil and gas (E&P) operations would continue to be regulated by the states and would be "exempt" from the RCRA Subtitle C regulatory regime. In response to this decision, IOGCC developed a set of environmental program guidelines for states to use in strengthening their oil and gas waste management programs (other than the UIC program) and, beginning in 1991, the IOGCC created the state review committee, comprised of state oil and gas regulators, state environmental regulators, major and local oil and gas producers, and members of the environmental advocacy organizations to systematically review state oil and gas environmental regulatory programs against the guidelines. This process, called "state review," is ongoing today.

RCRA Exemption and State Review

Background

The 1976 Resource Conservation and Recovery Act (RCRA) language instructed EPA to develop regulations for the identification and management of hazardous waste. The following is a timeline of the actions that provided for the current exemption of oil and gas E&P wastes from the Subtitle C (hazardous waste) provisions of RCRA:

December 18, 1978—EPA published the first set of proposed hazardous waste management standards in the Federal Register (43 Fed. Reg. 58,946). This notice included a proposal to exempt six categories of "special wastes" from the RCRA Subtitle C regulations until further study could be completed. "Oil and gas drilling muds and oil production brines" were included as two of the six special wastes.

October 12, 1980—Congress enacted the Solid Waste Disposal Act Amendments of 1980 (Public Law 96-482), which amended RCRA. Among the amendments, Section 3001(b)(2)(A)—frequently referred to as the Bentsen Amendment—temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or gas." At the same time, Section 8002(m) required EPA to study these wastes and submit a Report to Congress evaluating

Appendix 16 *continued*

the status of their management and potential risk to human health and the environment by October 1982. EPA was also required to make a regulatory determination (within six months of the completing the Report to Congress) as to whether these wastes warranted regulation under RCRA Subtitle C or some other set of regulations.

August 1985—The Alaska Center for the Environment sued EPA for its failure to conduct the required study and submit its findings to Congress. EPA entered into a consent order obligating it to complete and submit the Report to Congress by August 31, 1987.

December 1987—EPA submitted a three-volume Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy (EPA530-SW-88-003, Volumes 1-3).

July 6, 1988—The EPA Administrator issued a Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes, July 6, 1988 (53 Fed. Reg. 25,466), which stated that EPA believed the regulation of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted. Rather than subjecting E&P waste to the Subtitle C provisions, EPA planned to implement a three-pronged strategy to address the issues posed by these wastes by improving federal programs under existing authorities such as Subtitle D of RCRA, the Clean Water Act, and the Safe Drinking Water Act; working with states to encourage changes and improvements in their regulations and enforcement; and working with Congress to develop any additional statutory authorities.

March 22, 1993—The EPA Administrator issued a Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy (58 Fed. Reg. 15,284), which clarified the regulatory status of wastes generated by the crude oil reclamation industry, service companies, gas plants and feeder pipelines, and crude oil pipelines. EPA only provided further clarification on the status of these wastes under the exemption and did not alter the scope of the original exemption in any way.

October 2002—EPA issued the publication, "Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations." This document provided a clarification of the exemption of certain oil and gas E&P wastes from regulation as hazardous wastes under RCRA Subtitle C. The document included background on the E&P exemption, basic regulations for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of E&P waste mixtures, and clarifications of several misunderstandings about the exemption.

The State Review Process

As a critical part of EPA's 1988 regulatory determination to exempt oil and gas wastes from the Subtitle C provisions of RCRA, EPA pledged to help states improve their regulatory programs. Subsequently, the Interstate Oil and Gas Compact Commission (IOGCC), which represents the

Appendix 16 *continued*

governors of oil and gas producing states, formed the Council on Regulatory Needs and received a grant from EPA to identify the categories of effective state regulatory programs. The Council was created in 1989 as a forum where state oil and gas and environmental regulators, environmental groups, and industry representatives could work together to achieve this goal. After eighteen months, the Council produced a guidelines document, which was published in 1990 and updated and expanded in 1994. The guidelines were used as the basis for reviewing state programs by multi-stakeholder review teams. The purpose of the state review program is to provide an ongoing assessment of the effectiveness of state E&P waste regulatory programs in protecting the environment.

The State Review Process Becomes "STRONGER"

Incorporated as a non-profit corporation in June 1999, State Review of Oil and Natural Gas Environmental Regulations (STRONGER) became the independent stakeholder governing body that manages the state review process. Its Board of Directors consists of three state regulators, three environmental/public interest representatives, and three industry representatives. EPA, DOE, and the Department of the Interior participate as non-voting Board members. The IOGCC also participates through its State Review Committee, which provides for liaison with the states, provides three state regulators to serve on the Board, and provides state regulators to participate in periodic updates to the guidelines. In 2000, and again in 2005, STRONGER updated and expanded the guidelines to remain current with emerging environmental concerns and regulatory program developments. Subjects addressed in the current guidelines include general/administrative, technical, abandoned sites, naturally occurring radioactive materials (NORM), and stormwater management. Following the 2000 guidelines revisions, STRONGER added regulations for participation, designed to govern the selection of participating states, preparation for reviews, conduct of reviews report writing, and dispute resolution. As of 2013, 22 states had undergone either an initial STRONGER review and follow-up review or a hydraulic fracturing review. (Appendix 11).

Post 1990: The Era of Environmental Regulation Refinement

The last two decades have provided new environmental regulatory challenges to oil and gas. Many states formed separate departments to administer overall environmental regulations because of the programmatic shift in emphasis toward protection of water and land resources and the special technical knowledge needed to implement programs. Such changes provided better coordination of environmental permitting and field inspection activities and improved documentation of accountable actions to state legislatures, the public, and the petroleum industry. Several states revised existing regulations concerning pits, tanks and well construction during this period to reflect the latest technological, environmental, and public policy needs of the state. There was also an increased level of enforcement against those operators who failed to

Appendix 16 *continued*

maintain compliance. During this period, several states including Kansas, Oklahoma, Indiana, and Louisiana set up formal penalty schedules and operator suspension procedures to address habitual or flagrant non-compliance. The types of penalties that, at one time, only applied to Class II (oil and gas related) injection wells were now utilized for a whole range of environmental programs. Operators were also subjected to increases in well and/or performance bonding requirements and additional financial assurance requirements.

In addition, increased environmental awareness has resulted in the implementation of several new environmental programs. Some of these programs are listed below.

- The discovery of coalbed methane (CBM) in Montana, Wyoming, the Four Corners area, and the Black Warrior Basin of Alabama, brought the search for gas into some categories previously unexplored for hydrocarbons. Colorado and California, which had always regulated oil and gas at the state level, now experienced increased pressure from citizens to have a significant part of regulation done through county or city ordinance, often in duplication to the mandate of the state regulatory agency. In 2008, Colorado revised its regulations to allow for expanded public participation in the permitting and environmental assessment of oil field sites. This participation included review by other state water protection agencies.

- In the mid-1990s citizens became concerned over the amount of naturally occurring radioactive material (NORM) that was being produced at some oil and gas lease locations. Some produced water had sufficient radium and other radioactive isotopes to develop a coating of precipitate in tubular goods and at pump connections. Operators were concerned when loads of salvage pipe were rejected by prospective buyers and were returned to them for disposal. As a result, some states such as Louisiana and Texas developed regulations governing the disposition of this pipe and other NORM materials and wastes.

- The Community Right-To-Know portion of Superfund (Section 312 of SARA Title III) of 1988 required oil operators to submit Material Safety Data Sheets (MSDS) reporting how much hydrocarbon was stored on-site at a lease facility. At the state level, this program is usually administered by the principal state environmental agency rather than the oil and gas regulatory agency. This law also has a provision under Section 304 whereby the operator has to make changes in a facility design if a large release of hydrocarbons occurs.

- The Oil Pollution Act (OPA) of 1990 has had some impact on oil and gas production operations, primarily throughout the U.S. coastal areas of Louisiana, Texas, Mississippi,

Appendix 16 *continued*

and Alabama. This act began as a reaction to the Exxon Valdez incident in Alaska in 1988 and required the use of double-hulled vessels to transport oil.

Today, many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field regulations, and "Best Management Practices (BMPs)." They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing, and plugging.

Inside back cover
[This page is intentionally blank]