UNIVERSITY of HOUSTON

FINAL REPORT

WELL STIMULATION REGULATION REVIEW FOR BSEE

E14PC00037

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1 ACRONYMS

API	American Petroleum Institute
BBL	Barrels
BLM	Bureau of Land Management
BOEM	Bureau of Energy Management
BOP	Blowout Prevention System
BSEE	Bureau of Safety and Environmental Enforcement
CEL	Cement Evaluation Log
DOI	Department of Interior
EIR	Environmental Impact Report
EMW	Equivalent Mud Weight
EPA	Environmental Protection Agency
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
SB	Senate Bill
SPE	Society of Petroleum Engineers
STMZ	Single-Trip Multi-Zone

2 DEFINITIONS

Abnormal Pressure	Any geopressure different from the established normal trend for the given area depth.
Acid Fracture	To part or open fractures in rock formations by using acidic fluid under hydraulic pressure.
Acid Stimulation	A well stimulation method using acid.
Additive	A product composed of one or more chemical constituents that is added to a primary carrier fluid to modify its properties in order to form hydraulic fracturing fluid.
Annulus	The region around a pipe in a wellbore.
Ballooning	Effect caused by a change in average pressure inside or outside of a tubing string.
Bending Stress	Compressive and tensile forces that develop in the direction of the beam axis under stressing loads.
Buckling	The tendency of a string of tubing bend and give way under pressure or strain.
Casing	A large-diameter pipe that is lowered and cemented in the wellbore to isolate the formation and formation fluids.
Conduit	Casing strings serving to directly transport fracturing fluids and additives from the pumps the formations to be stimulated.
Chemical Abstract Services (CAS) Number	The unique identification number assigned to a chemical by the division of the American Chemical Society that is the globally recognized authority for information on chemical substances.
Chemical Constituent/Ingredient	A discrete chemical with its own specific name or identity, such as a CAS number, that is contained in an additive.
Chemical Family	A group of chemicals that share certain physical and chemical characteristics and have a common general name.

Completion	The activities and methods used to prepare a well for production after drilling.
Conventional Reservoir	Reservoir in which formation characteristics and conditions allow for formation fluids to flow readily into the wellbore.
Design of Casing	The collective process of analyzing loads applied to a pipe (casing) string during a specified operation and selection of casing that exceeds the applied loading conditions. During the pipe selection process, casing shall include the pipe, connectors and all components of the casing string.
Direct Conduit	Direct conduct includes all pipe, connectors, and components of the casing string that are used for conveyance of any fluids and additives, including proppants, from the rig to the formations involved in the stimulation process. This conduit may include production casing, one or more of the intermediate casing strings, expendable or sacrificial casing, and liners. This conduit does not include conductor/drive pipe or surface casing.
Dog Leg	A bend in the wellbore trajectory, or path, where the direction of the well's path changes completely.
Drilling Fluids	Often called drilling *mud*, drilling fluids are used during the drilling process for the purpose of cooling and lubricating the bit, cleaning the hole bottom, circulating cuttings, and controlling formation pressure.
During Stimulation Operations	All operations related to the stimulation process including rig up, pressure testing, running the casing and completion equipment, perforating, high pressure pumping, post pumping operations, monitoring and flowback to include transfer of flow back fluids from their holding tanks to transport vessels.
Erosion	The effects of wear and material degradation caused by fluid flow; typically a slurry or suspended solids.
Expendable Casing	Casing or tubular string that is used to perform hydraulic fracturing stimulation treatments and is disposed of upon completion. It is typically stung into the liner. See Sacrificial Casing.

Failure	A failure constitutes a disruption in service because a piece of equipment breaks or is no longer serviceable. A failure can be a malfunction of the equipment.
Flowback	Flowback refers to the returned (produced) fluids—along with other formation particles—after a hydraulic fracturing stimulation treatment has completed.
Formation Pressure	The pore and fluid pressure within a reservoir; typically characterized by hydrostatic pressure.
FracFocus.org	The chemical disclosure registry website developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.
Fracture Gradient	The minimum pressure required to induce fractures in a geologic formation at a given depth.
Fracturing Fluids	Fluid, such as water, oil, or acid, used in hydraulic fracturing stimulation treatments.
Horizontal Well	A well that is drilled directionally until it reaches an angle that is nearly 90 degrees from the vertical.
Hydraulic Fracturing	A stimulation treatment in which mostly water-based fracturing fluids are pumped into the wellbore at pressures that exceed the formation fracture pressure with the purpose of inducing fractures into the formation to enhance the productivity of the well.
Monitoring	The process of, and all required equipment, for detection, acquisition, and display of all data during stimulation operations. Also, monitoring shall include onboard data storage, real time transfer of the data to a secure offsite storage facility and preservation of the recorded data for a minimum of two years after completion of the monitoring process.
Lower Tertiary	The Lower Tertiary refers to an offshore, subsurface geologic formation—a region, particularly in the Gulf of Mexico, where the rock formations are typically characterized by high temperature and high pressure. High sand content and the presence of evaporate sediment layers are common in this region.

Material Safety Data Sheet (MSDS)	A written or printer document that is prepared for a chemical mixture or ingredient considered to be hazardous under OSHA standards according to OSHA's regulations on hazard communication at 29 C.F.R. §1910.1200(g)(2).
Matrix Acidizing	A stimulation treatment in which acid is injected into the wellbore at pressures below the formation fracture pressure with the purpose of dissolving soluble particles in the rock to increase the permeability of the formation.
Offshore Frac Vessel	A mobile maritime vessel—usually as barge or ship—that houses and transports well stimulation equipment and material to perform offshore well stimulation treatments.
Operator	A person who assumes responsibility for the physical operation and control of a well.
Owner	A person who owns, manages, leases, controls, or possesses a well property.
Primary Carrier Fluid	The base fluid, such as water, into which additives are mixed to form the hydraulic fracturing fluid that transports proppant.
Product	A hydraulic fracturing additive that is manufactured using precise amounts of specific chemical constituents and is assigned a commercial name under which the substance is sold or utilized.
Production Casing	A section of tubing that is used to isolate production zones and contain formation pressure. Production casing is typically perforated to allow formation fluids to access the wellbore.
Proppant	Sand or any natural or man-made material that is used in a hydraulic fracturing treatment to prop open the artificially created or enhanced fractures once the treatment is completed.
Sacrificial Casing	Casing or tubular string that is used to perform hydraulic fracturing stimulation treatments and is disposed of upon completion. It is typically stung into the liner. See Expendable Casing.
Seismicity	The occurrence or frequency of earthquakes in a region; in the context of well stimulation for the purposes of this report.

Service Company	An entity that performs hydraulic fracturing treatments on a well.
Stimulation	A treatment or operation performed on an oil or gas well to increase and/or enhance its productivity.
Supplier	A company that sells or provides an additive for use in a hydraulic fracturing treatment.
Thermal Loading	The temperature effects that cause casing or tubing tension and compression to change due to thermal contraction/expansion.
Trade Secret	Any formula, pattern, device, or compilation of information that is used in a person's business, and that gives the person an opportunity to obtain an advantage over competitors who do not know or use it.
Unconventional Reservoir	A reservoir that requires an external driver—or stimulation—to enhance the accessibility and flow of formation fluids into the wellbore.
Vertical Well	A well that is drilled into the subsurface at an angle of nearly zero.
Zonal Isolation	The exclusion of fluids (e.g. water, gas) in one zone from mixing with oil in another zone.

3 OBJECTIVE

The objectives for the tasks defined here in follows:

- Conduct a regulatory analysis of well stimulation techniques domestically and internationally to identify technical industry standards used by regulatory authorities; and
- Compare and contrast these technical standards to current regulations observed by the Bureau of Safety and Environmental Enforcement (BSEE).
- Provide recommendations with regards to well stimulation practices, techniques, and regulatory standards to BSEE.

The requisite tasks associated with each of these objectives have been completed.

4 CONCLUSIONS

Primary conclusions resulting from an investigation of oil and gas regulations follow:

- Environmental protection was the central theme of existing regulations. Ranked in order of emphasis, the concerns include (1) chemical disclosure of stimulation fluids and additives, (2) ground water protection, (3) protection of the local populous and environment in areas proximate to the stimulation site and (4) safe handling and disposal of flowback fluids including formation water.
- Existing regulations do not provide technical guidance for stimulated wells that are in addition to requirements for non-stimulated wells.
- The most comprehensive fracturing regulations have been promulgated by Illinois followed by California.
- The growth rate of stimulation technology has exceeded the regulator's ability to promulgate timely rules and regulations that are consistent and appropriate with the expanding technology.
- The Lower Tertiary formation in the Gulf of Mexico's OCS poses challenges that are more complex, difficult and substantially higher pressured than other regions worldwide.

The scope of the regulatory investigation focused on the following areas:

1. Well construction;
2. Hydraulic fracturing-specific regulation;
3. Chemical disclosure;
4. Post-treatment reporting;
5. Casing design for pressure pumping;
6. Cement design for pressure pumping;
7. Safety regulations during stimulation operations;
8. Environmental impact assessment;
9. Waste management;
10. Seismicity; and
11. Risk assessment.

- Regulations for acid-specific well stimulation treatments were not identified for any U.S. state.
- Due to ongoing and accelerating issuance, the research and analysis of well stimulation standards can't be effectively completed.

5 SUMMARY OF RESULTS

Summaries of the main conclusions derived from the acquisition and analysis of well stimulation regulations follows:

- Results from the analysis of existing regulations suggested the need for expanded coverage;
- Environmental issues were the central theme in existing regulations;
- The potential ramifications from an offshore stimulation incident with associated pollution should be considered when drafting future regulations;
- Consideration for future OCS stimulation regulations should include a technical component because the failure consequences far exceed the consequences associated with land-based events;
- It seems the drafters of existing regulations did not have significant input from technically competent personnel with stimulation knowledge, experience and familiarity with unplanned and unanticipated events during stimulation operations.

Additional conclusions are addressed in other sections of this report.

5.1 ACQUISITION AND ANALYSIS OF WELL STIMULATION REGULATIONS

Acquiring stimulation regulations for the fifty (50) US states was a straight forward task. After analyzing the obtained regulations, several groupings of these regulations developed based on the following criteria including:

- States that do or don't produce significant and commercial quantities hydrocarbons,
- States that have or have not published oil and gas regulations
- States that have published oil and gas regulations that do or don't contain stimulation-specific rules.

Five (5) groups of US states were established, outlined in Table 1:

Table 1 – Grouping of US States by regulatory language.

Group No.	Description	Reference
1	Hydrocarbon-Producing, US States with Well Stimulation-Specific Rules	Appendix A
2	Non-Hydrocarbon-Producing, US States with Well Stimulation-Specific Rules	Appendix B
3	No hydrocarbon production, oil and gas regulations, with stimulation-specific rules.	Appendix C
4	Non-Hydrocarbon-Producing, US States without Well Stimulation-Specific Rules	Appendix D

Acquisition of foreign oil and gas regulations was a greater challenge than anticipated for several reasons:

- Most international oil and gas producing entities publish their regulations in the country's native language without an accessible English translation. Unsuccessful attempts were made to source these foreign regulations with the assistance of foreign graduate students from the Department of Petroleum Engineering at the University of Houston;
- Some foreign countries, such as China, delegates rulemaking responsibilities to state-owned oil and gas companies;

- All available regulations were studied and an Excel spreadsheet was developed as a means to compare/contrast the regulations. The compare and contrasting task was a complex challenge.
- Norwegian rules and regulations were acquired and studied. Many industry members consider Norway's regulations, as a whole, establish a *Gold Standard* for comprehensiveness and technical depth. Norway's NORSOK D-010, *Well Integrity Guidelines* were unique because they provided technical details, quantitative and qualitative, that are lacking in other regulations.

5.2 RECOMMENDATIONS FOR BSEE's CONSIDERATION FOR FUTURE OCS STIMULATION REGULATIONS

A significant effort was put forth towards the development of meaningful recommendations for BSEE's consideration for future OCS Stimulation Regulations These recommendations are contained in Section 8 of this report. Numerous obstacles had to be addressed including the following:

- US States regulations were limited in their primary focus subjects and, as a result, did not provide widespread guidance for future offshore regulations;
- Attributes of land-based stimulation technology are reasonably understood but not necessarily applicable to offshore applications;
- Offshore stimulation in the Lower Tertiary zone must address challenges including, but not limited to, abnormally high formation pressures and pressure gradients in the interval to be stimulated, perforation of long intervals in one trip of the perforating gun, high negative pressures while perforating, shock loads on the downhole equipment from perforating;
- Lack of prior OCS stimulation regulations that could have served as a building block for future regulations;
- Limited experience and technical publications exists for the Lower Tertiary;
- The industry had an expanding need to develop and downhole equipment that addresses stimulation-related loading conditions associated with stimulation in the Lower Tertiary zone; and

- Fracturing related casing/coupling failures observed in land operations may or may not be transferable to offshore stimulation.

6 INTRODUCTION

6.1 INTRODUCTION TO WELL STIMULATION

Well stimulation refers to any treatment performed to enhance the productivity of a well by improving the conductivity for formation fluids. Although several well stimulation methods have been employed by the industry throughout the years, there are currently two principal treatments that are routinely used to enhance oil and gas productivity today. They are acidizing and hydraulic fracturing.

Acidizing is a treatment applied to essentially enhance the conductivity of near-wellbore fluids. In matrix acidizing, acid is pumped into the wellbore at pressures below the fracture gradient—the minimum pressure required to induce fractures in rock at a given depth. The injected acid interacts with soluble formation particles to improve permeability, enhancing the conductivity of formation fluids in the vicinity of the wellbore. Although different acids may be used to treat different geologic formations, the stimulation principle is the same.

Acidizing has been used effectively for many years to reduce near-wellbore formation damage. Recently the role for acid has expanded to fracturing. In many cases, acid has been used as the lead fluid in hydraulic fracturing to etch the fracture surface and further increase fluid conductivity.

Hydraulic fracturing is a technique in which a specially formulated, water-based fluid is injected into the well at pressures exceeding the fracture gradient of the formation. Fractures induced by the fracturing fluid create new channels in the formation, providing reservoir fluids greater access to the wellbore. Solid particles (called proppants), mixed with the fracturing fluid, maintain these newly created fractures in an open position. After completion of a hydraulic fracturing treatment, a period of time exists where downhole fluids are returned to the surface during. This process is referred to as flowback. Flowback consists of a fraction of the original fracturing fluid, as well as dissolved minerals, hydrocarbons and formation water. Most US regulations impose strict standards for disposal of flowback fluids.

6.2 STIMULATION OVERVIEW

Well stimulation techniques were first conducted in the early twentieth century. U.S. patents for increasing and enhancing the productivity of oil wells dates back to as early as 1936. Hydraulic fracturing utilized in the commercial application of enhancing the productivity of oil-and-gas wells was first conducted in the late 1940's—almost a decade later. Advancements in well stimulation technology over the years and recent developments in the exploration of unconventional resources have made stimulation a routine option for enhancing the productivity of wells—particularly in the United States.

Hydraulic fracturing technology has actually been used by the oilfield for about 60[1] years and is applied in 85-90% of the natural gas wells currently drilled in the United States. Some estimate that as much as 60% of the natural gas and 30% of the oil produced in the United States each day would be stranded without hydraulic fracturing – and an astounding 80% of all wells drilled in the next decade will require it.

6.3 CONVENTIONAL AND UNCONVENTIONAL RESOURCES

The term unconventional has become increasingly common in recent years despite there not being a standard industry definition in place. Unconventional reservoirs have low permeabilities, usually less than one millidarcy, and are shale-based. In practice, unconventional reservoirs require an external driver—or stimulation—to commercially extract resources. On the contrary, it is understood that "conventional"

[1] Hydraulic Fracturing: Stimulating Reservoirs to Increase Natural Gas Production (http://public.bakerhughes.com/ShaleGas/fracturing.html)

reservoirs, usually sand, have greater permeabilities and produce resources without the use of any well stimulation treatment.

6.4 OVERVIEW OF DIFFERENCES IN STIMULATION PRACTICES BETWEEN THE U.S. STATES, AND THE OCS, INCLUDING THE LOWER TERTIARY

A brief comparison of stimulation practices between US land and the OCS including the Lower Tertiary will assist in placing OCS stimulation in its appropriate technical perspective. Current typical land practices uses a horizontal well to penetrate and expose long sections of the reservoir. Lengths of the lateral ranges from 500-600 ft up to 5,000 ft, or more. The reservoir pressure is in the general range of being normal, or 0.465 psi/ft (approximately 9 lbm/gal), but with a few exceptions where pressure may be in the range of 0.624-0.676 psi/ft — or 12-13 lbm/gal such as in portions of the Eagle Ford shale. The well fractured in stages. A case history example of a well that was drilled and hydraulically stage-fractured is provided in Appendix G. Post-stimulation flowback may require from 2-3 days up to 60 days.

Selection and arrangement of the stimulation equipment for OCS wells will be different than land wells. Figure 1 shows a sketch of the key equipment components arranged for fracturing on land while Figure 2 is an exemplar surface equipment layout for a land-based stimulation operation. The wellhead is the center point for spotting the requisite equipment. The wellhead is connected to the stimulation pumps with high pressure pump lines—up to 20,000 psi. Line diameters are typically 3-4 inches. A number of 500-bbl frac tanks are located around the site to provide the necessary fresh water supply, proppant, acid if it is to be used, and other necessary chemicals. All of the stimulation equipment is digitally connected to a control/command center where the equipment can be operated by a single individual. The control center also monitors, displays and captures data coming into the center. The land site layout usually can be expanded as required to accommodate the equipment requirements.

OCS stimulation does not have the same degree of flexibility for equipment arrangement as for land sites. A self-contained stimulation vessel is used. The “stim” or “frac” boat aligns its stern to one side of the rig where a high pressure, large diameter flexible “pump line(s)” is lifted up to the side of the rig and attached to a permanent receptacle. Safety latches are closed and locked to prevent "lift off" of the vessel's flexible line during high pressure operations.

Figure 3 shows a typical stimulation vessel used in the OCS area with various pieces of equipment. The subject vessel in this illustration is Baker Hughes's *Blue Orca*. It houses five Baker Hughes Gorilla™ pumps, each capable of delivering 2,750 HHP. The vessel can transport 2,500,000 lb_m (1,134 tons) of sand or equivalent proppant. Eight lined tanks hold 180,000 gallons of liquids.

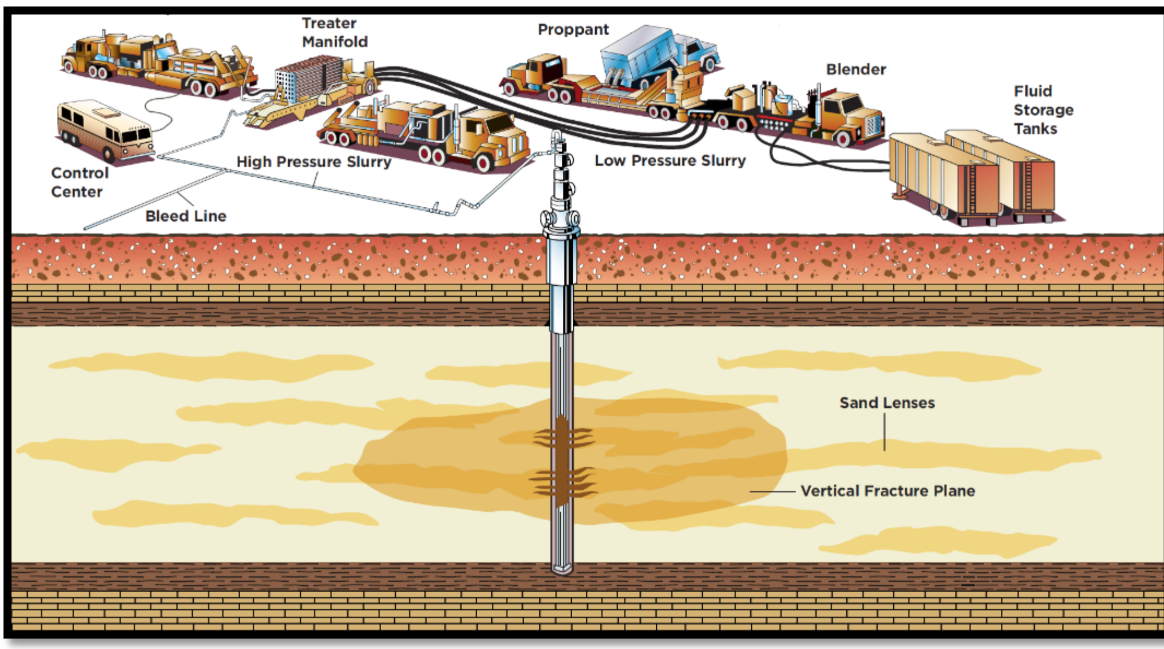

Figure 1 – Sketch of stimulation equipment on a land site.

Figure 2 – Stimulation equipment on a site in the Marcellus Shale.

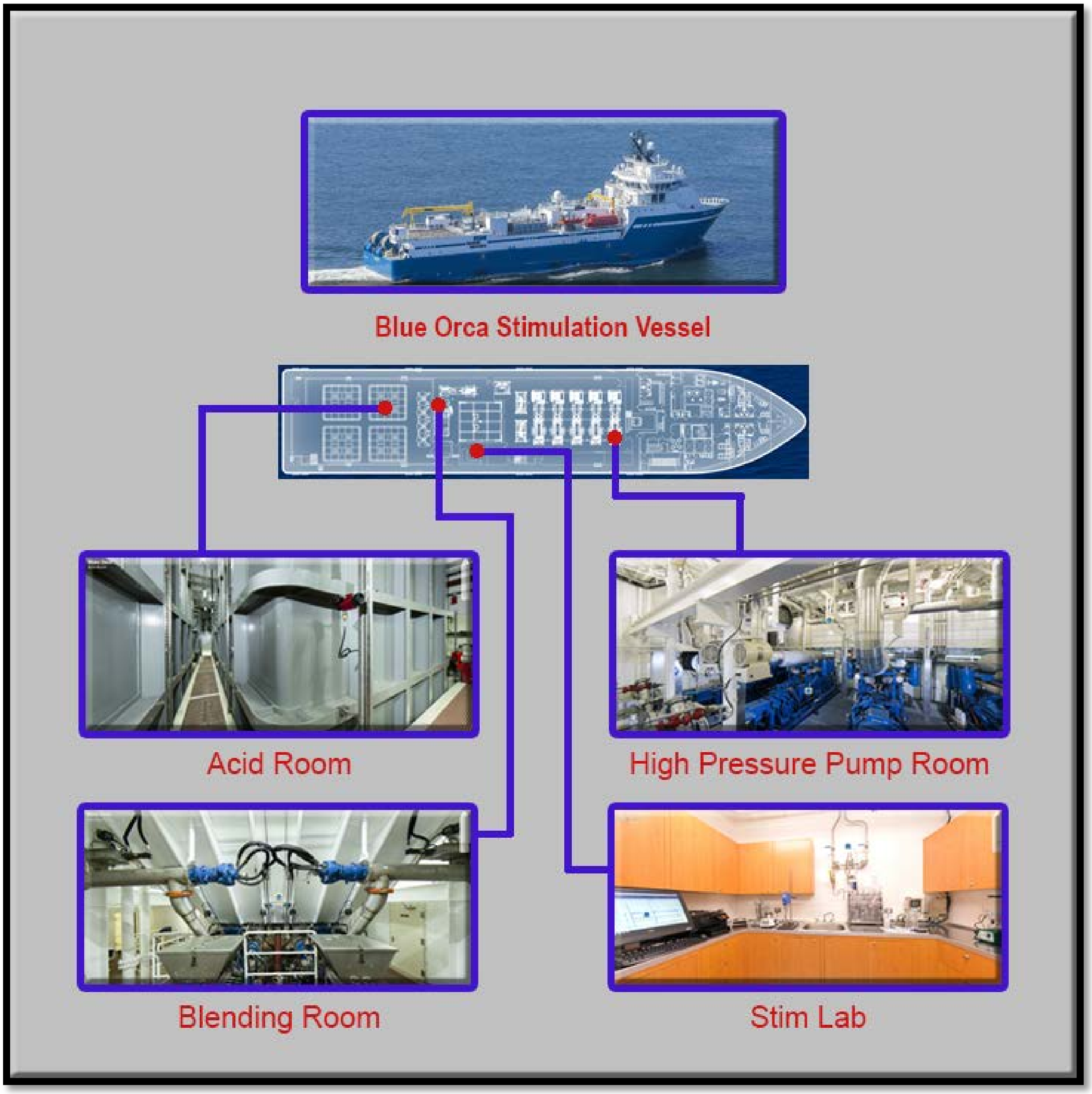

Figure 3 – Offshore stimulation vessel, Baker Hughes's Blue Orca.

6.5 OCS GEOLOGY AND THE LOWER TERTIARY FORMATION

A few words about rocks (formations) will assist in understanding OCS stimulation practices. Current stimulation operations in the OCS are associated with two rock types—*soft* or *hard* rock. The formation's Young's modulus is the rock property that controls the soft vs. hard rock classification. A geologically young formation is often described as soft. Geologically older formations have an increased Young's modulus, and consequently, increased hardness. Stimulation success in soft rock formations is typically less than desired.

As noted, the success of a fracturing operation is a function of the rock's hardness or Young's Modulus. A hydraulic fracturing operation applies significant pressure to a hydraulic-like fluid to create, open, and extend the newly created fractures. The fractures tend to close when the pressure is released. To avoid frac closure, an agent/material is mixed with the pumped fluids entering the fracture. This material is generally known as a proppant and is designed to "prop" open, the fracture or prevent fracture closure, when the fluid pressure is released. Soft formations collapse around the proppant and allow fracture closure. Hard rocks have a sufficiently high Young's modulus to prevent fracture closure, i.e. the proppant successfully maintains fracture separation which creates the permeable path for hydrocarbon flow into the wellbore. Although sand is the most widely used proppant, it may not be typically used in the Lower Tertiary because stresses associated with fracture closure crush the sand thus allowing frac closure. Instead, Bauxite is the preferred proppant because it is substantially stronger than sand and can resist crushing.

Until recently, OCS stimulation operations have been conducted on geologically young—or soft—formations. The Lower Tertiary formations, which are considered as hard rock have been the recent stimulation target, particularly in fields such as the Cascade and Chinook fields operated by Petrobras in the Gulf of Mexico. A typical profile for the Cascade and Chinook wells is shown in Figure 4. The Lower Tertiary formation is separated in two sections: (1) Wilcox 1 of Eocene origin and (2) and Wilcox 2, a Paleocene zone.

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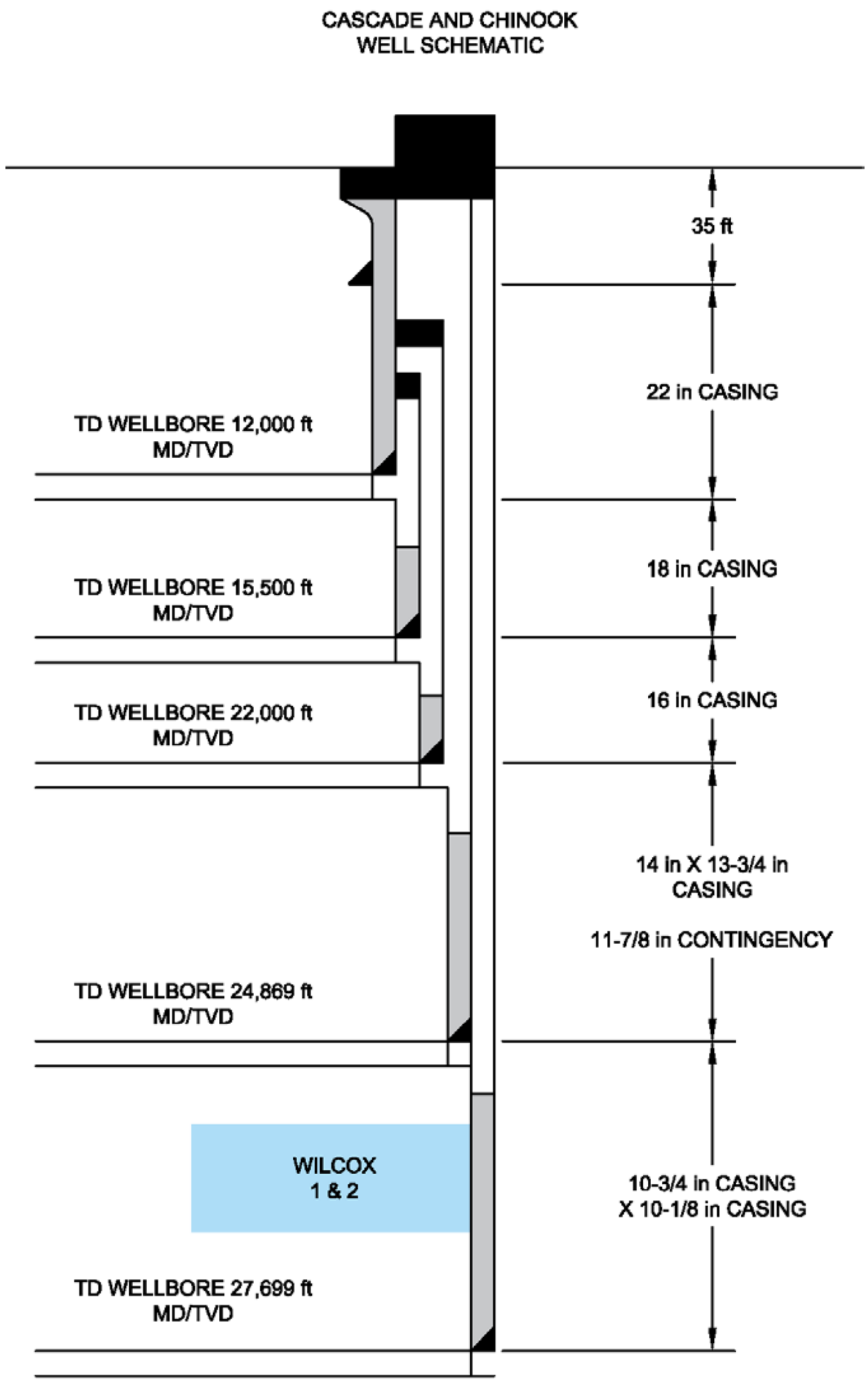

Figure 4 – Typical schematic for wells in the Cascade and Chinook Fields.

These reservoirs are characterized by a thick zone of sandstone and shale. Permeability estimates are less than 100 mD with poor vertical communication. The static formation pressure exceeds 19,000 psi and has a maximum temperature of 256°F, and a low gas-oil ratio. The operating window for drilling is shown in Figure 5. The hydrocarbon's gaseous phase has approximately 1.5% carbon dioxide (CO_2). These fields are found in water depths of about 9,000 ft, and the Lower Tertiary formation is nearly 26,000 ft TVD.

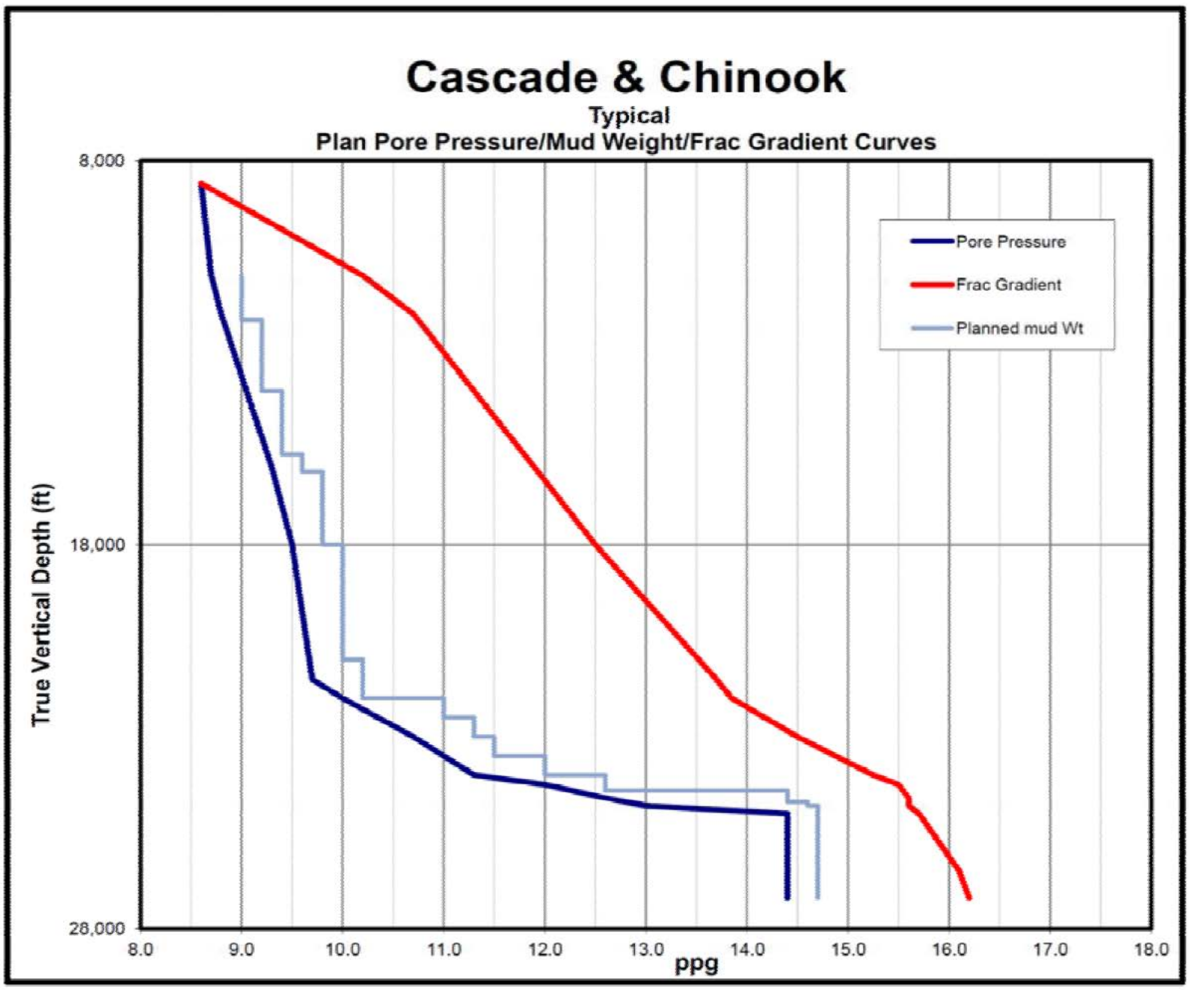

Figure 5 – Operating window profile for wells in the Cascade and Chinook fields. The window is substantially reduced in the lower hole sections.

Due to the extreme conditions associated with the Lower Tertiary, virtually every aspect of the completion process and particularly its associated equipment requires extensive testing and frequently requires design modifications. As an example, the use of bauxite as the proppant has resulted in erosion issues one manufacturer's downhole completion tools.

A single-trip multi-zone sand control (frac-pack) system seems to be used in many Lower Tertiary formations. The STMZ system reduces the number of required trips in the well and has been successfully used to simultaneously perforate sand thicknesses up to 1200 feet under negative differential pressures of about 12,000 psi. An example of a typical STMZ tool assembly setup is shown in Figure 6.

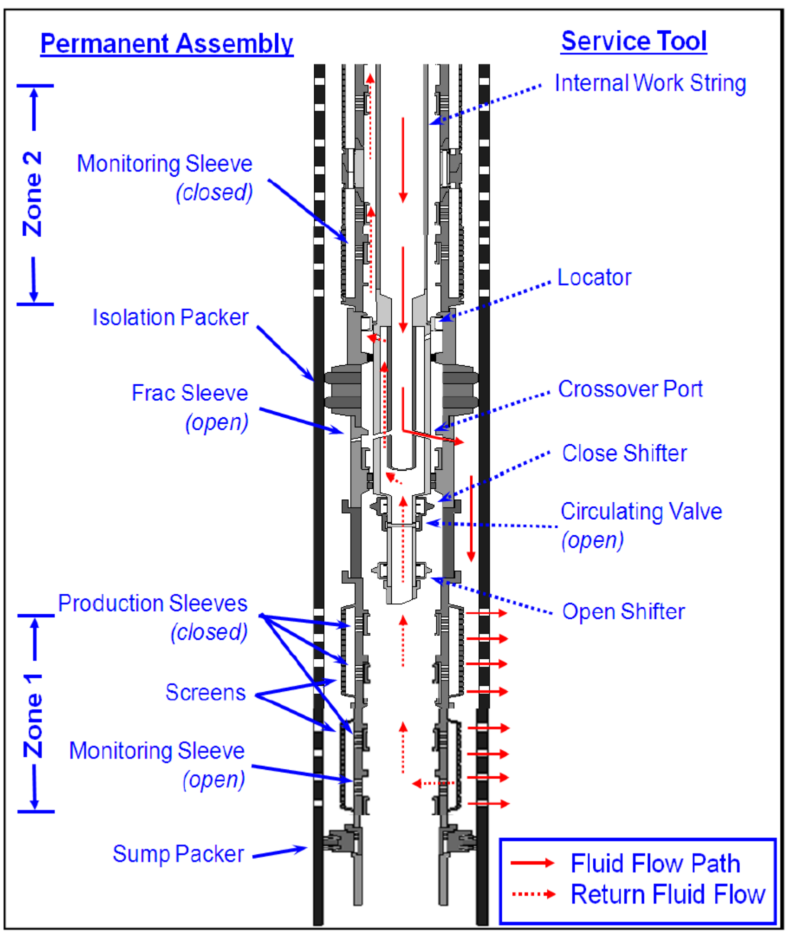

Figure 6 – STMZ completion used for some of the Lower Tertiary wells.

7 ANALYSIS OF WELL STIMULATION REGULATIONS

This report section describes the process used for regulation acquisition and the subsequent analysis. A means to compare and contrast regulations is discussed. Results are presented from the analysis of US and pertinent foreign countries.

7.1 ACQUISITION OF OIL AND GAS REGULATIONS

Oil and gas regulations from each of the fifty (50) US states were identified and acquired where they were available. The analysis results showed that thirty-two (32) of the fifty (50) states produced oil and/or gas and each of these states had published rules and regulations relating to various aspects of the oil industry. Further, eighteen (18) states did not produce meaningful quantities of hydrocarbons, however, six (6) of those non-hydrocarbon-producing states did, in fact, have oil and gas regulations in place. Hydrocarbon-producing U.S. states with well stimulation-specific rules are listed in Table 2. Hydrocarbon-producing U.S. states without any well stimulation-specific rules are provided in Table 3. U.S. states that do not produce meaningful quantities of hydrocarbons and do not have well stimulation-specific rules, in those states in which oil and gas regulations apply, are listed in Table 4.

The pertinent regulations from each of the thirty-eight (38) states that have oil and gas regulations were identified, downloaded, filed and studied. Further, of the thirty-eight (38) states, only twenty-four (24) contained stimulation-specific rules (shown in Appendix A). The recently released regulations from the U.S. Department of the Interior's Bureau of Land Management were also acquired and studied.

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Table 2 – Hydrocarbon-producing, US states with well stimulation-specific rules.

No	State	Regulatory Authority	Reference Source
1	Alabama	State Oil and Gas Board of Alabama	State Oil and Gas Board of Alabama Administrative Code, Oil and Gas Report 1, Rules and Regulations Governing the Conservation of Oil and Gas in Alabama and Oil and Gas Laws of Alabama with Oil and Gas Board Forms
2	Alaska	Alaska Oil and Gas Conservation Commission	Alaska Administrative Code
3	Arizona	Arizona Oil and Gas Conservation Commission	Arizona Administrative Code, Title 12. Natural Resources, Chapter 7. Oil and Gas Conservation Commission
4	Arkansas	Arkansas Oil and Gas Commission	General Rules and Regulations as of August 01, 2014
5	California	California Department of Conservation, Division of Oil, Gas and Geothermal Resources	Statues and Regulations for Conservation of Oil, Gas, and Geothermal Resources
6	Colorado	Colorado Oil & Gas Conservation Commission	Oil and Gas Conservation Act of the State of Colorado
7	Illinois	Illinois Department of Natural Resources	Illinois Administrative Code, Title 62. Mining, Chapter I. Department of Natural Resources, Part 245. Hydraulic Fracturing Regulatory Act
8	Kansas	Kansas Oil and Gas Conservation Division	General Rules and Regulations for the Conservation of Crude Oil and Natural Gas
9	Kentucky	Kentucky Department of Natural Resources	Commonwealth of Kentucky Oil and Gas Well Operations Manual
10	Louisiana	Louisiana Department of Natural Resources	Title 43. Natural Resources. Part XIX. Office of Conservation—General Operations. Subpart 1. Statewide Order No. 29-B
11	Mississippi	Mississippi Oil and Gas Board	State of Mississippi Statues, Rules of Procedures, Statewide Rules and Regulations
12	Montana	Montana Department of Natural Resources	Rule Chapter: 36.22 Oil and Gas Conservation
13	Nebraska	Nebraska Oil and Gas Conservation Commission	Rules and Regulations of the Nebraska Oil and Gas Conservation Commission
14	Nevada	Nevada Commission of Mineral Resources	Adopted Regulation of the Commission on Mineral Resources, LCB File No. R011-14
15	New Mexico	New Mexico Oil Conservation Commission	New Mexico Oil Conservation Division
16	North Dakota	North Dakota Industrial Commission	North Dakota Administrative Code, Rules and Regulations
17	Ohio	Ohio Department of Natural Resources	Ohio Administrative Code, 1501:9 Division of Mineral Resources Management – Oil and Gas
18	Oklahoma	Oklahoma Corporation Commission	Title 165. Corporation Commission, Chapter 10. Oil and Gas Conservation
19	South Dakota	South Dakota Department of Environment and Natural Resources	South Dakota Rules, Chapter 74:12:02:19 Hydraulic Fracturing Reporting Requirements
20	Tennessee	Tennessee Board of Water Quality, Oil and Gas	Rules of the Tennessee Department of Environment and Conservation

No	State	Regulatory Authority	Reference Source
21	Texas	Texas Railroad Commission	Reference Source: Texas Administrative Code, Title 16. Economic Regulation
22	Utah	Utah Division of Oil, Gas and Mining	R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.
23	West Virginia	West Virginia Department of Environmental Protection	Title 35. Legislative Rule, Series 8. Rules Governing Horizontal Well Development
24	Wyoming	Wyoming Oil and Gas Conservation Commission	Wyoming State Rules, Chapter 3. Operational Rules, Drilling Rules

Table 3 – Non-hydrocarbon producing US state with well stimulation specific rules.

No.	State	Regulatory Authority
1	North Carolina	Division of Energy, Mineral, and Land Resources

Table 4 – Hydrocarbon-producing, US States without well stimulation-specific rules.

No.	State	Regulatory Authority
1	Florida	Florida Geological Survey
2	Indiana	Indiana Department of Natural Resources, Division of Oil and Gas
3	Michigan	Michigan Department of Environmental Quality
4	Missouri	Missouri Department of Natural Resources, Division of Geology and Land Survey
5	New York	New York Bureau of Oil and Gas Regulation
6	Oregon	Oregon Department of Geology and Mineral Industries
7	Virginia	Virginia Department of Mines, Minerals and Energy
8	Pennsylvania	Pennsylvania Department of Environmental Protection

Table 5 – Non-hydrocarbon-producing, US states without well stimulation-specific rules.

No.	State	Regulatory Authority
1	Connecticut	*No oil and gas agency*
2	Delaware	*No oil and gas agency*
3	Georgia	Department of Natural Resources
4	Hawaii	*No oil and gas agency*
5	Idaho	Idaho Department of Lands
6	Iowa	*No oil and gas agency*
7	Maine	*No oil and gas agency*
8	Maryland	Maryland Department of the Environment
9	Massachusetts	*No oil and gas agency*
10	Minnesota	*No oil and gas agency*
11	New Hampshire	*No oil and gas agency*
12	New Jersey	*No oil and gas agency*
13	Rhode Island	*No oil and gas agency*
14	South Carolina	Bureau of Land and Waste Management
15	Vermont	*No oil and gas agency*
16	Washington	Division of Geology and Earth Resources, Washington Geological Survey
17	Wisconsin	*No oil and gas agency*

Largely with success, a similar effort was made to gather oil and gas regulations from international sources. The countries for which regulations were available and acquired include Norway, United Kingdom, and Canada's hydrocarbon-producing provinces. These three countries with oil and gas regulations are listed in Table 5. The European Union regulations were also studied. The difficulty encountered while gathering international regulations was that most countries published their respective regulations in their native languages and do not provide an English Translation. However, Norway is considered by most industry personnel as having the most demanding regulations in the industry and clearly surpasses all US-sourced regulations in terms of coverage.

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Table 6 – List of international countries with oil and gas regulations

No.	State	Regulatory Authority
1	Norway	Norwegian Petroleum Directorate
2	Canada	Government of Canada
3	United Kingdom	Environment Agency (EA) in England, Scottish Environment Protection Agency (SEPA) in Scotland and Natural Resources Wales (NRW) in Wales, Health and Safety Executive (HSE) and the Department of Energy and Climate Change (DECC)

Each set of regulations, domestic and foreign, was studied to identify any items that specifically applied to well stimulation. After identification, the pertinent fracture-related rules were excerpted and filed Regulations for the US states are found in Appendices A through D and the international regulations are in Appendix E. The US Federal Regulations, BLM and BSEE, are shown in Appendix F. Document formatting from state-to-state was understandably inconsistent. These Appendices show the documents as is from their original sources.

7.2 COMPARE AND CONTRAST THE ACQUIRED REGULATIONS

Each set of regulations was studied. As should be imagined, these regulations varied widely in terms of format, scope and depth. Some placed more emphasis on chemical disclosure for components of fracturing fluids while others were on ground water protection. Quickly, it became obvious that developing a means to compare-and-contrast the regulations would be a substantial challenge. A spreadsheet was developed as a means of comparison of specific topics from the regulations. The focus was to develop clear and objective comparisons but, admittedly, some of the work was reduced to subjective comparisons.

The spreadsheet developed for comparative purposes of US regulations is shown in Tables 7. Each line contains a state that has published oil and gas regulations. Columns have been established to identify various topics related to stimulation. Table 8 provides a description for each of the 11 topics.

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Table 7 – Comparison of U.S. States with oil and gas regulations containing stimulation-specific rules.

No.	State	Well Construction	Hydraulic Fracturing	Chemical Disclosure	Post-Treatment Report	Casing Design for Fracturing	Cement Design for Fracturing	Fracturing Through Production Casing	Safety Regulations During Stimulation	Environmental Impact Assessment	Waste Management	Seismicity	Risk Assessment
1	Alabama		•	•	•								
2	Alaska												
3	Arizona		•										
4	Arkansas	•	•	•	•								
5	California	•	•	•	•	•	•		•	•	•	•	•
6	Colorado		•	•	•								
7	Illinois	•	•	•	•	•	•		•		•		
8	Kansas			•									
9	Kentucky			•									
10	Louisiana			•							•		
11	Mississippi		•	•									
12	Montana	•	•	•					•				
13	Nebraska	•	•	•									
14	Nevada	•	•	•	•								
15	New Mexico		•										
16	North Carolina	•	•						•				
17	North Dakota	•	•	•									
18	Ohio	•	•										
19	Oklahoma												
20	South Dakota			•									
21	Tennessee		•	•	•						•		
22	Texas	•	•	•		•	•						
23	Utah		•	•									
24	West Virginia		•						•		•		
25	Wyoming		•	•									

Table 8 – Description of topics covered in the comparison spreadsheets.

Category	Description
Well Construction	The term “well construction” is commonly used as an encompassing description that includes the planning, drilling, and well completions. Some, but not all, of the items falling under this category include well planning, rig selection, drilling operations, design and installation of casing strings, cementing, drilling problems such as well control, and reporting to regulatory authorities. Regulations with respect to each of these items should apply to all wells within the jurisdiction of the regulation agency, whether the well is drilled/not stimulated or drilled/stimulated. This column denotes specific regulations for well construction that are applicable only to stimulated wells. As an example, does the regulation contain special instructions for casing design in a well to be fractured where those instructions are not applicable to all drilled wells?
Hydraulic Fracturing Stimulation	Do the regulations contain language applicable to the planning, process or execution of hydraulic fracturing?
Acid Stimulation	A distinction is made between acidizing processes that have been widely used for many years to increase production from conventional reservoirs and acid usage while stimulating unconventional reservoirs.
Chemical Disclosure	Are operators required to disclose the chemical composition of the fracturing fluids, additives and proppants? FracFocus.org is a commonly used website for chemical disclosures. These disclosures are in addition to required MSDS fact sheets.
Post Treatment Reporting	Is the operator required to submit a post-treatment report that outlines the key data from the well stimulation treatment? This submission is different than post-treatment reports prepared by the service provider for the operator. (Appendix E

Category	Description
	contains a sample post treatment report submitted to the Operator by the service provider.) The most comprehensive and preferred approach would be for the operator to submit a copy of post-treatment reports prepared by the service provider.
Casing Design for Fracturing	Casing for most wells is designed for burst, collapse, tension, compression, and perhaps bi-axial/tri-axial analysis. Most regulations specific to stimulation require only that the casing is designed to handle the maximum anticipated surface treatment pressures. Hydraulic stimulation loads the casing with many stringent conditions in addition to burst. Are these additional loading conditions addressed in the regulations?
Cement Design for Fracturing	Do the regulations contain unique cement provisions for wells to be stimulated versus well that will not be stimulated?
Fracturing Through Production Casing	Most Operators fracture through the production casing that has been run and cemented. To reduce the risk that stimulation may damage the production casing, some operators install a temporary casing string/liner, inside the existing casing, use for fracturing. This temporary string is removed after the stimulation is completed. Common terms for the temporary fracturing string are *expendable* or *sacrificial* strings.
Safety Regulations during Stimulation	Are additional safety regulations imposed during stimulation that aren't active for non-stimulated wells?
Environmental	Is a formal EIA required prior to stimulation or post-stimulation?

Category	Description
Impact Assessment	
Waste Management	This topic addresses only those waste products generated during stimulation operations with a focus on flow back processes including water, fracturing fluids, polymers, and proppants.
Seismicity	This topic addresses earthquake activity. As related to fracturing, does the stimulation process result in earthquake activity during or after stimulation? Pre- and post-stimulation seismicity studies may be required. Does the regulations require a long term monitoring program?
Risk Assessment	Is a formal risk assessment (RA) required for evaluation of real or imagined stimulation hazards?

An overview of the spreadsheet in Tables 7 and 8 can be used to quickly identify states with more or less regulations than other states. Each state was studied to identify its specific stimulation requirements.

As a general observation, most state regulations focused on environmental issues and failed to provide full coverage of stimulation-related issues. This observation is made from this investigator's perspective of having experiences in land-based stimulation operations and also an involvement in the investigation of failures occurring while stimulating a well. Simply stated, existing regulations are not current with modern stimulation technology.

For further explanation, consider the prior example of burst design for casing to be used during stimulation operations. Computer simulation analysis, which are based on assumed rock properties, can be used to predict the maximum anticipated surface treating pressures for each fracturing stage. Most current regulations require that the casing be pressure tested to a value equal to the calculated maximum anticipated surface treating pressure. This regulation does not consider the possibility of an unexpected sandout (screen out) where the surface pressure can quickly and easily exceed the maximum anticipated surface treating pressure before the pumps can be stopped. A more appropriate regulation would require pressure testing to a reasonable value greater than the maximum anticipated surface treating pressure.

Stimulations places additional loads and substantial stresses that don't apply to casing during non-stimulation completions. These loading conditions are described in greater detail in Section 8. The appropriate stress calculations for each loading condition can be complicated. Each independently calculated stress load must be added to other calculated stresses to determine the ultimate pipe load. Most of the regulations reviewed during this study fail to address these loading conditions.

7.3 INTERNATIONAL REGULATIONS

7.3.1 Norway

Oil and gas regulations are enacted and enforced by the Norwegian parliament—or *Storting.* Parliament enacts regulatory legislation with the support of ministries, subordinate directorates and standards agencies. For example, The National Petroleum Directorate (NPD) is administratively subordinate to the Ministry of Petroleum and Energy (MPE). Private and independent organizations such as Standards Norway develop regulations for oil and gas industry practices. Standards Norway is particularly recognized for their NORSOK standards which are the focus for the regulations covered in this report. The following is an excerpt from the foreword of *NORSOK D-010* covered in Appendix E.

> *"The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries. NORSOK standards are administered and issued by Standards Norway.*

The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of a NORSOK standard will be used to provide input to the international standardization process. Subject to implementation into international standards, the NORSOK standard will be withdrawn."

Regulations released by other organizations and/or ministries in Norway are not discussed in this report.

7.3.2 United Kingdom

Stimulation regulations in the United Kingdom (UK) are handled differently for land vs. offshore operations. The onshore guidelines are found in UK Onshore *Shale Gas Well Guidelines*, Issue 3, March 2015. They are put forth by the United Kingdom Onshore Oil and Gas, UKOOG. According to the document's Foreword,

"The guidelines are relevant to UK onshore shale gas wells designed and constructed for the extraction of naturally occurring hydrocarbons which includes stimulation by techniques involving high volume hydraulic fracturing"

Further in the Foreword,

"The guidelines contain what is considered to be good industry practice and they reference the relevant legislation, standards and practices."

As noted, the document contains guidelines considered to be good industry practice and discusses some stimulation guidelines located in other UK regulations. The onshore guidelines contained in this publication primarily focuses on management strategies and assurances rather than technical aspects of the stimulation process. Several examples follow:

- Section 2.1, Management Systems under Section 2, Safety and Environmental Management. "To assist in discharging their responsibilities, operators and other duty holders should operate in accordance with effective management systems and ensure that personnel are competent in the tasks they are required." It appears the operator and/or duty holder is left to interpret this passage without further guidance from the regulations.
- Section 4.1 Well Design and Construction as taken from the publication Offshore Installations and Wells (Design and Construction, Etc.) Regulations, 1996 (DCR) specifies the general duties of the Well Operator in connection with wells. "The Well Operator shall ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned that (a) so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and (b) risks to health and safety of persons for it or anything in it, or in strata to which it is connected, are as low as reasonable practicable.

These types of regulations are general and fail to provide specific guidance to operators. Often, these regulations leave the Operator with more questions rather than solutions.

UK's offshore guidelines are found in Well integrity guidelines published by the United Kingdom Offshore Oil and Gas Industry Association, Limited (trading as Oil & Gas UK). This publication addresses all offshore wells but does not contain any references to stimulation. As noted in its Foreword,

> *"The guidelines are relevant to all wells and well operations in Great Britain for the extraction of naturally occurring hydrocarbons. The guidelines described what is believed to be good industry practices and refer to relevant legislation, standards and practices. The guidelines concentrate on 'typical' wells and 'standard' operations."*

The UK government has received some criticism for its lack of stimulation-specific regulations. The government's general response to this criticism is that all necessary regulations, including for stimulation operations, are covered by existing general regulations.

7.3.3 Canada

Hydraulic fracturing is an integral piece of Canadian energy production. Authority for oil and gas regulations is shared by the Federal government and Provincial governments. The Federal government regulates oil and gas activities on frontier lands (most of Yukon, Nunavut and Northwest Territories), certain offshore and territorial lands. Canada's provinces have jurisdiction over their onshore resources. Regulations have been gathered and studied for the Federal government and the provinces of Alberta, British Columbia, New Brunswick, Newfoundland and Labrador, Nova Scotia, Ontario, Manitoba, Prince Edward Island, Quebec and Saskatchewan.

7.3.4 European Union (EU)

The European Union is a politico-economic union of 28 member states that are located primarily in Europe. The EU operates through a system of supranational institutions and intergovernmental-negotiated decisions by the member states. The institutions are: the European Commission, the Council of the European Union, the European Council, the Court of Justice of the European Union, the European Central Bank, the European Court of Auditors, and the European Parliament. The European Parliament is elected every five years by EU citizens. Member states include Australia, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, The Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and the United Kingdom.

The EU is not authorized to write or enforce legislation on member states. Member states have the right to determine the conditions for exploiting their energy resources, as long as they respect the need to preserve, protect and improve the quality of the environment. After substantial debate and numerous scientific studies, the EU recognizes there is a need to lay down minimum principles which should be taken into account by the Member States when applying or adapting their regulation related to activities involving high-volume hydraulic fracturing. As of January 2014, the Commission issued its recommendations on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing. This document is contained in Appendix E, Section 9.5.4.

7.4 FEDERAL REGULATIONS

7.4.1 Introduction

7.4.2 Bureau of Land Management (BLM) Regulations

The US Department of the Interior (DOI) released new fracturing regulations on 20 March 2015 in the document, "Final Rule to Support Safe, Responsible Fracturing Activities on Public and Tribal Lands". This document is §3162.3 in the Code of Federal Register. Secretary of the Interior Jewel noted the following:

> *"Current federal well-drilling regulations are more than 30 years old and they simply have not kept pace with the technical complexities of today's hydraulic fracturing operations."*

A DOI news release on the same day as the issuance of the new regulations noted four key components of the new rule.

- Provisions for ensuring the protection of groundwater supplies by requiring a validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes;
- Increased transparency by requiring companies to publicly disclose chemicals used in hydraulic fracturing to the Bureau through the website FracFocus™, within 30 days of completing fracturing operations;

- Higher standards for interim storage of recovered waste fluids from hydraulic fracturing to mitigate risks to air, water and wildlife; and
- Measures to lower the risk of cross-well contamination with chemicals and fluids used in the fracturing operations, by requiring companies to submit more detailed information on the geology, depth, location of preexisting wells to afford the BLM an opportunity to better evaluate and manage unique site characteristics.

A copy of this new rule has been studied and included in Appendix E for the reader's convenience.

The BLM regulations of 2015 lacks appropriate coverage of numerous topics deemed to be important by this Investigator. A brief description of some of the perceived deficiencies follow:

- Although the document is clearly designed to protect the environment, it fails to consider the safety of the individuals involved during the operations, or the safety of the actual fracturing operations;
- The requirements of this rule are deemed to be much weaker than many state (U.S.) regulations;
- Casing strings exposed to the hydraulic fracturing operations should be designed to resist all loads imposed by the fracturing operations including, but not limited to, burst, collapse, tension, compression, tri-axial loading, ballooning, applied stresses from thermal cooling, buckling, bending stresses related to wellbore dog-legs, erosion, fatigue and combined stress loading;
- A post-fracturing CEL should be run and compared to a pre-fracturing CEL. Possible changes to the cement as a result of fracturing operations should be analyzed and, where appropriate, a remedial plan of action should be developed and implemented. After any remedial actions, another CEL should be run and compared to prior CELs;
- Language associated with flowback operations should be strengthened. Numerous operational accidents during the flowback phase of fracturing operations have resulted in injuries and fatalities, primarily from ignition of hydrocarbon components of the flowback fluids. Crews often overlook safety fundamentals of handling hydrocarbons such as no smoking in the area,

separation between ignition sources and flammable hydrocarbons and static electricity. Some flowback operations may take extended time periods, sometimes days or weeks, which can result in crew complacency;

- The requirements for information that must be provided to the authorized officer after hydraulic fracturing should include all items listed in the BLM rule and expanded to include:
    1. A copy of the post treatment report(s) provided by the service provider to the operator
    2. A flowback report to include:
        a. flow back pressures, rates and volumes versus time; and
        b. details of the disposal of the flowback fluids returned from the well;
- All unplanned events and/or injuries and fatalities that occur during the stimulation or flowback operations must be immediately reported.

This list is not designed as all-inclusive of perceived deficiencies.

7.4.3 Outer Continental Shelf Regulations

Source: Title 30 of the Code of Federal Register, Chapter II, Subparts D and E.

A search of the Code of Federal Register was conducted to identify regulations for drilling and completion operations or other regulations that may be pertinent to stimulation. Subpart D covers drilling while Subpart E addresses completions. Several conclusions were formed including the following:

- CFR rules with respect to drilling operations were more comprehensive and detailed than regulations from US states and most foreign countries. Norwegian regulations are the exception;
- The CFR does not contain stimulation-specific regulations;
- The CFR should be updated to include stimulation-specific regulations; and
- Any new stimulation-specific rules should consider the conditions associated with the Lower Tertiary.

The recommendations contained in Section 8 should be considered when drafting stimulation regulations.

7.5 APPLICABLE DOCUMENTS FROM THE AMERICAN PETROLEUM INSTITUTE

The American Petroleum Institute (API) publishes three documents dedicated to hydraulic fracturing. Stimulation coverage in these publications is similar to the comprehensive regulations from Illinois and California. A list of these three documents follows:

- API HF1, *Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines,* 1st Edition, October 2009;
- API HF2, *Waste Management Associated with Hydraulic Fracturing,* 1st Edition, June 2010; and
- API HF3, *Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing,* 1st Edition, January 2011.

Stimulation coverage in the three API documents is similar to regulations from Illinois and California. The API indicates that API HF2 and API HF3 are currently being revised into a single publication, ANSI/API RP 100-2, *Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing,* 2015 Edition, August 2015. It is not currently available (28 August 2015). In addition to these three documents, the API has many publications that should be considered in the fracturing and execution process. These items (publications) typically apply to stimulated and non-stimulated wells.

7.5.1 HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, 1st Edition, October 2009

The purpose of this guidance is to identify and describe many of the industry recommended practices for well construction and integrity for wells that will be hydraulically fractured. The guidance provided here will help to ensure that shallow groundwater aquifers and the environment will be protected, while also enabling economically viable development of oil and natural gas resources. This document is intended to apply equally to wells in either vertical, directional, or horizontal configurations. Topics addressed in HF1 include fracture barriers and containment (natural and mechanical); well construction, design considerations, testing; cementing practices, job execution, job evaluation; operational practices; isolation requirements; well logging, testing; hydraulic fracturing; and data collection.

As previously noted, many aspects of drilling, completing, and operating oil and natural gas wells are not addressed in this document but are the subject of other API documents and industry literature. Companies should always consider these documents, as applicable, in planning their operations.

Maintaining well integrity is a key design principle and design feature of all oil and gas production wells for the two following reasons.

- To isolate the internal conduit of the well from the surface and subsurface environment. This is critical in protecting the environment, including the groundwater, and in enabling well drilling and production.
- To isolate and contain the well's produced fluid to a production conduit within the well.

Although there is some variability in the details of well construction because of varying geological, environmental, and operational settings, the basic practices in constructing a reliable well are similar. These practices are the result of operators gaining knowledge based on years of experience and technology development and improvement. These experiences and practices are communicated and shared via academic training, professional and trade associations, extensive literature and documents and, very importantly, industry standards and recommended practices.

7.5.2 HF2, Waste Management Associated with Hydraulic Fracturing, 1st Edition, June 2010

The purpose of HF2 is to identify and describe many of the current industry best practices used to minimize environmental and social impacts associated with the acquisition, use, management, treatment, and disposal of water and other fluids associated with the process of hydraulic fracturing. While this document focuses primarily on issues associated with hydraulic fracturing pursued in deep shale gas development, it also describes the important distinctions related to hydraulic fracturing in other applications.

Moreover, this guidance document focuses on areas associated with the water used for purposes of hydraulic fracturing and does not address other water management issues and considerations associated with oil and gas exploration, drilling, and production. These topics should be addressed in future API documents.

7.5.3 HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing, 1st Edition, January 2011

The purpose of HF3 is to identify and describe practices currently used in the oil and natural gas industry to minimize surface environmental impacts–potential impacts on surface water, soil, wildlife, other surface ecosystems and nearby communities–associated with hydraulic fracturing operations. While this document focuses primarily on issues associated with operations in deep shale gas developments, it also describes the important distinctions related to hydraulic fracturing in other applications. Topics in the proposed API 100-2 document that combine HF2 and HF3 include site selection (surface, visual, noise, road use); spill prevention, control and response; logistics planning; baseline sampling; water source management; material selection for HF fluids; transportation of materials and equipment; mobilization, rig-up, demobilization; data collection, analysis, and monitoring; storage and management of fluids and chemicals on-site; flowback recovery; management of solid and liquid wastes; and air quality.

7.6 IEA's GOLDEN RULES

The International Energy Agency published *Golden Rules for a Golden Age of Gas* in 2012. This document contains principles that can allow policymakers, regulators, operators, and others to address environmental and social impacts of production from unconventional reservoirs. The rules underline that full transparency, measuring and monitoring of environmental impact, and engagement with local communities are critical to addressing public concern.

The principles established in these documents follows:

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas- producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.

- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.

- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

7.7 Review and Summation of Current Rules & Regulations:

A deliverable of the project is assessment of current regulations identified in this report. The assessment was conducted by CSI investigators, Cooke Law Firm, and Superior Completion Services as directed in the PMP. This section of the report presents executive summary of that review and evaluation. Suggested areas the group identified as issues potentially warranting regulation are also identified here. All regulations identified in this report were reviewed and summarized by the investigators.

The summary of regulations is presented in Appendix G of this report. Note that several U. S. states had detailed, specific regulations governing well construction and hydraulic fracturing. The majority of states, however, did not. The regulations for Norway were notably complicated and difficult to follow.

In general, the investigators reviewing the regulations agreed that risk of losing OCS wellbore integrity from stresses imposed during stimulation operations could be decreased via following appropriate design, engineering, and operational guidelines.

This review has also been submitted to the Industry Advisory Group for review and comment.

The regulations reviewed herein were categorized into five major subjects: Well Location, Well Construction, Hydraulic Fracturing, Waste Management, and Seismicity. Each major category is discussed below with both summary of existing regulations and consensus of topics relevant to OCS operations.

Well Location:

Summary of Existing Regulations

- These rules are set to protect fresh water sources and communities living in the area.
- The distance of the well from fresh water source and/or community varies from 300 to 1500 ft.

OCS Focus

Freshwater sources and communities are not an issue here. However, comparing spacing between wellbores to treatment volume may prevent unwanted fracture or wellbore interference.

Well Construction:

Summary of Existing Regulations

- In 2010, BSEE established comprehensive rules and regulations for well construction and cement job design and operations.
- Most states have standard cement composition recommendations.

OCS Focus

The current BSEE regulations and certification procedures for well cementing and casing design (CFR 250.420 through 250.428) are comprehensive, straight forward, and easy to follow. The well plans written to address these procedures and accompanied by the API Standard 65-Part 2 Compliance Summary demonstrate the operator's adherence to the regulations. The investigators agree that any BSEE regulations for OCS stimulation should follow the format established for cementing.

In light of the relationship identified between seal integrity during hydraulic fracturing and cement mechanical properties, physical properties, and well dimensions, (described in the final technical report for this project), guidelines for production cementing performance may be of benefit. These guidelines would address cement mechanical properties, physical properties, cement column height, and minimum annular radius.

Hydraulic Fracturing:

Summary of Existing Regulations

- Fracturing program should detail the volume of the fluids and concentrations of additives to be used.
- Safety data sheets of all chemicals should be available.
- Tracers can be used but should have a pre-arranged disposal plan
- Fracturing program should include fracture propagation simulation.
- The maximum allowable treatment pressure varies from 70 % to 100% of the casing or fracturing string burst pressure.
- Equipment and treating lines pressure test before treatment is generally performed at 110% of the anticipated pressure differential.
- Pressure test acceptance varies from 10% in 10 minutes decline to 5% in 30 minutes.
- Use of diesel and organic solvent is prohibited or very restricted in most states.
- All annuli pressures should be monitored and recorded during the treatment.
- If fracturing treatment results in irreparable damage to the mechanical integrity of the well, the well should be plugged and abandoned.

OCS Focus

The current regulations summarized above all have application for OCS wells. Specific OCS parameters should be established for pressure test performance, material identification, annular pressure monitoring, and reporting.

Waste Management

Summary of Existing Regulations

- Closed aboveground tanks or lined pits should be available on location to recover and temporarily store flowback fluids, produced water, hydraulic fracturing fluids and additives.
- Produced water and flow back fluids may be treated and recycled in fracturing or enhanced oil recovery operations.

- Any release of hydraulic fracturing fluid, chemical, flowback fluid or produced water should be reported, immediately cleaned up and remediated.
- Some states require that the flowback fluids be tested before removal from the site.

OCS Focus

Current regulations for environmental protection during OCS well operations are sufficient for stimulation treatments.

Seismicity

Summary of Existing Regulations

- California and Illinois have regulations for monitoring seismic activity before and after hydraulic fracturing jobs to identify any induced earthquake (attributable to high pressure injection of fluids)

OCS Focus

Monitoring or prevention of seismic events resulting from stimulation treatment is not believed to be a major concern in OCS due to geology and relatively small numbers of wellbores and fracturing treatments.

8 RECOMMENDATIONS FOR CONSIDERATION IN FUTURE BSEE OCS REGULATIONS

8.1 PERMIT APPLICATION FOR WELL STIMULATION

Permit application for well stimulation treatment should include all data/information provided previously in the Application for Permit to Drill. In addition, the permit application for well stimulation treatment should include the following:

a) Final designs, including all calculations and assumptions, for casing, cement, stimulation, flowback, monitoring and contingency plans;
b) A detailed description of the proposed high volume hydraulic stimulation operations including the final job proposal prepared by the selected service provider;
c) The maximum anticipated surface treating pressure;
d) Estimated or calculated fracture pressure of the producing and confining zones;
e) Estimated or measured formation pressure of the producing and confining zones;
f) Planned depth of all proposed perforations;
g) Chemical disclosure that identifies each chemical and additive anticipated to be used during stimulation operation; and
h) Estimated total required volume of water and/or acid.

8.2 WELL CONSTRUCTION

8.2.1 Casing Design Including Pipe Selection

a) Casing design criteria apply to those inner casing strings that will serve as a conduit for high pressure fracturing.
b) The minimum internal yield pressure rating shall be based upon engineering calculations list in API's TR 5C-3 *Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe used as Casing and Tubing, and Performance Properties Tables for Casing and Tubing.*

c) Casing shall be designed for burst, collapse, axial loading (tension/compression), and a triaxial analysis of the combined loads. In addition to designing for burst, collapse, axial loading (tension/compression), and triaxial analysis for the combined loads, the casing shall be designed to exceed any loading conditions imposed on the casing during running and stimulation operations including, but not limited to, the following:

i. Ballooning;
ii. thermal changes (cooling and/or heating);
iii. buckling;
iv. bending stresses associated with wellbore dog-legs or other sources of pipe bending;
v. annular pressure changes;
vi. erosion;
vii. abrasive composition of fluids;
viii. corrosion, metallurgical composition in relation to exposure to the formation or drilling fluids left in the annulus prior to stimulation;
ix. fatigue;
x. estimated or measured wear;
xi. particle loss over the life of the well;
xii. negative differential pressure while perforating; and
xiii. the cumulative effects of the loads when applied to the casing

d) Minimum acceptable design factors for burst, collapse, axial loading, and triaxial analysis are shown in Table 8.

Table 9 – Minimum design factors for casing.

Burst	1.1
Collapse	1.1

Axial Loading	1.25
Triaxial Analysis	1.25

e) Collapse design shall consider partial or complete evacuation of fluids inside the casing.

f) Design for pipe burst must exceed the maximum anticipated surface treating pressures by 10%.

g) Burst design shall assume no external pressure.

8.2.2 Pipe and Coupling Design

All casing used as a direct conduit of hydraulic fracturing fluids and additives during the stimulation process shall be:

a) New pipe;

b) Steel alloy pipe;

c) Seamless;

d) Manufactured at an API-licensed manufacturing facility within 24 months of its intended usage;

e) Manufactured and tested consistent with standards established by the American Petroleum Institute (API) according to its *5CT Specification for Casing and Tubing*;

f) Contain appropriate documentation and/or certificates as proof of purchase, tracking of the pipe from manufacturer to the end use site, testing results from mechanical or hydraulic testing process where the document/certificates shall be made available as part of the post-treatment report;

g) Connectors must meet or exceed all design requirements and loading conditions for casing; and

h) Connector performance properties shall exceed all stress requirements placed on the connector including make-up torque.

8.2.3 Directional Drilling

If directional drilling is required, dog-legs should be maintain less than 5°/100ft.

8.3 CEMENT DESIGN

The following cementing requirements for conduit casing during stimulation operations are in additional to cementing requirements for non-stimulated wells.

a) The top of cement for any conduit casing transporting fracturing fluids shall be determined with the use of cement evaluation log(s) (CEL);
b) The top of the cement must be 500 ft above the depth of the shallowest stimulation perforation; and;
c) Quality and effectiveness of the cement shall be evaluated with CEL logs;

When to run CEL logs:

a) CEL logs shall be run after cementing any casing string used as a conduit for fracturing fluids;
b) CEL logs shall be run to determine the top of cement and evaluate cement effective;
c) CEL logs shall be run after stimulation through a conduit for fracturing fluids;
d) The results from the initial CEL log and the post-stimulation CEL shall be compared and analyzed;
e) A remedial plan to correct any observed cement deficiencies as a result of operations during stimulation must be prepared and executed;
f) A CEL log shall be run after remedial operations and compared to previously run CEL logs; and
g) Any further deficiencies must be correct through remedial operations.

8.4 STIMULATION OPERATIONS

8.4.1 Casing/Coupling Make-up

a) Equipment used to make-up each connection in the casing string shall use torque tracking technology to measure and record applied torque and number of rounds for pipe make-up.

b) The manufacturer's recommended thread compound must be used for the selected couplings. An alternative thread compound may be used if it can be proved that it provides an improvement over the manufacturer's recommended thread compound.

c) Operations must immediately cease if a casing or coupling failure occurs.

d) If a casing and/or coupling failure occurs during stimulation operations, all reasonable efforts shall be made to acquire and retain all pieces, parts, components; and the upper and lower joints of the casing at the point of failure. The acquired pieces, parts, components and upper/lower joints of the casing at the point of failure shall be retained and stored at a third-party's secured site for a minimum of one year after the time of the failure.

e) An Electronic Data Recorder (EDR) system shall be used and fully active while running the casing and during stimulation operations. The maximum time frequency between each instance of data acquisition and storage shall not be greater than five (5) seconds. Upon request, all data acquired and stored by the EDR system shall be made available to a representative of BSEE within 15 days of the time that that request is made. The data must be available, as a minimum, in an editable ".csv" format.

f) Any connection that must be broken during the running and installation process shall be removed and not reused.

8.4.2 Casing Pressure Testing

a) Prior to installation of the casing, it shall have been pressure tested to 100% of its burst rating.
b) Successful pressure tests of the casing string and/or any of its components shall meet the acceptance criteria of zero-leak and zero-pressure reduction throughout the time period established for the test.
c) Any leaks or pressure reductions during the test period shall cause an immediate work stoppage.
d) A diagnostic program must be implemented to identify the source of the leak or the cause for the pressure reduction.
e) A remediation plan must be developed and successfully implemented for the casing and/or any of its components.
f) The casing must be successfully retested under the same testing criteria as used in the initial but unsuccessful pressure test.
g) Testing results must be chartered and digitally recorded. The maximum time frequency between each occurrence of data acquisition shall be five (5) seconds.

8.5 CHEMICAL DISCLOSURE

In the case of any well fractured the following shall apply:

a) Vendor and service provider disclosures.
   i. Service providers who perform any part of a hydraulic fracture or provide hydraulic fracturing additives directly shall, with the exception of information claimed to be a trade secret, furnish the operator with the information required by subparagraph (b) of this paragraph, as applicable.

ii. Such vendors and service providers shall provide this information as soon as possible within 30 days following the conclusion of the fracturing activity and in no case later than 90 days after the commencement of the fracturing activity.

b) Operator disclosures.

i. Within 60 days following the conclusion of a hydraulic fracture, and in no case later than 120 days after the commencement of such hydraulic fracturing activity, the operator of the well shall complete the chemical disclosure registry form and post the form on the chemical disclosure registry, including:

1. operator name;
2. lease number;
3. date of the hydraulic fracture;
4. offshore block in which the well is located;
5. API number for the well;
6. well name and number;
7. longitude and latitude of the wellhead;
8. true vertical depth of the well;
9. measured depth of the well
10. total volume of water used in the hydraulic fracturing of the well or the type and total volume of the base fluid used in the fracturing, if something other than water;
11. Each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief description of the intended use and function of each hydraulic fracturing additive in the hydraulic fracturing fluid;
12. Each chemical intentionally added to the base fluid;
13. maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid; and

14. chemical abstract service (CAS) number for each chemical intentionally added to the base fluid, if applicable.

c) If the vendor, service provider, or operator claim that the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical is/are claimed to be a trade secret, the operator of the well shall so indicate on the chemical disclosure registry form and, as applicable, the vendor, service provider, or operator shall submit to the Supervisor a Claim of Entitlement Form notifying the Supervisor that the specific identity of a chemical, the concentration of a chemical, or both is being withheld as a trade secret. The operator shall nonetheless disclose all information required under subparagraph (b) of this rule that is not claimed to be a trade secret. If a chemical is claimed to be a trade secret, the operator shall also include in the chemical registry form the chemical family or other similar descriptor associated with such chemical. Unless the information is entitled to protection as a trade secret, information submitted to the Supervisor or posted to the chemical disclosure registry is public information.

d) Inaccuracies in information.

    i. A vendor is not responsible for any inaccuracy in information that is provided to the vendor by a third party manufacturer of the hydraulic fracturing additives. A service provider is not responsible for any inaccuracy in information that is provided to the service provider by the vendor. An operator is not responsible for any inaccuracy in information provided to the operator by the vendor or service provider.

e) Disclosure to health professionals.

    i. Vendors, service companies, and operators shall identify the specific identity and amount of any chemicals claimed to be a trade secret to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a confidentiality agreement. The written statement of need shall be a statement that the health professional has a reasonable basis to believe that:

1. The information is needed for purposes of diagnosis or treatment of an individual;
2. The individual being diagnosed or treated may have been exposed to the chemical and is concerned; and
3. knowledge of the information will assist in such diagnosis or treatment.

The confidentiality agreement shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the specific identity and amount of any chemicals claimed to be a trade secret are necessary for emergency treatment, the vendor, service provider, or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgment by the health professional that such information shall not be used for purposes other than the health needs asserted and that that health professional shall otherwise maintain the information as confidential. The vendor, service provider, or operator, as applicable may request a written statement of need, and a confidentiality agreement from all health professionals to whom information regarding the specific identity and amount of any chemicals claimed to be a trade secret was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall in no way be construed as publicly available.

8.5.1 Disclosures Not Required

A vendor, service provider, or operator is not required to: (a) disclose chemicals that are not disclosed to it by the manufacturer, vendor, or service provider; (b) disclose chemicals that were not intentionally added to the hydraulic fracturing fluid; or (c) disclose chemicals that occur incidentally or are otherwise unintentionally present in the trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid.

8.5.2 Trade Secret Protection

Vendors, service companies, and operators are not required to disclose trade secrets to the chemical disclosure registry or in the Well History Report if the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical are claimed to be entitled to protection as a trade secret, the vendor, service provider or operator may withhold the specific identity, the concentration, or both the specific identity and concentration of the chemical, as the case may be, from the information provided to the chemical disclosure registry or in the Well History Report

a) The vendors, service providers, or operators, as applicable, shall provide the specific identity of a chemical, the concentration of a chemical, or both of a chemical claimed to be a trade secret to the Board upon request from the Supervisor stating that such information is necessary to respond to a spill or release or a complaint from a person who may have been directly and adversely affected or aggrieved by such spill or release. Upon receipt of a written statement of necessity, such information shall be disclosed by the vendor, service provider, or operator, as applicable, directly to the Supervisor or his representative and shall in no way be construed as publicly available.
b) The Supervisor or his representative may disclose information regarding the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to the extent that such disclosure is necessary to allow respective groups receiving the information to assist in responding to the spill, release, or complaint, provided that such individuals shall not disseminate the information further.

8.6 POST-TREATMENT REPORTING

The operator shall file a well history, work summary, monitoring data, report of any unplanned incidents, pipe and/or equipment failures, and completion/recompletion reports within 60 days after stimulation or re-stimulation. Wells shall be considered completed when they are capable of being produced. Well history shall include the actual materials and volumes used to fracture, the amounts and concentrations of any additives used, the amount of waste fluids generated and the proposed method for disposal of waste fluids. Post-Treatment Summary Report (job reports, activity reports, etc.) prepared by a service provider shall be provided.

8.7 CONTINGENCY PLANNING

Contingency plans for the following list of events shall be prepared and submitted as part of the application process. The list is not inclusive of all scenarios where contingency planning may be required. Some events may not be present during all types of stimulation operations.

a) Unanticipated disconnect between the stimulation vessel and the rig during stimulation operations;
b) Loss of station-keeping capability for the drilling rig;
c) Loss of station-keeping ability for the fracture vessel;
d) Surface equipment failures (or malfunctions);
e) Unanticipated disconnect from the rig to subsea equipment;
f) Planned disconnect from the rig to the subsea equipment;
g) Failure or leaks in any of the conduits that carry high pressure fracturing fluids to the underground stimulation target formation;
h) BOP failures;
i) Unanticipated pressure loss;
j) Unanticipated pressure change in the annulus;
k) Failure of downhole completion equipment;
l) Failure of downhole equipment during flow back operations;
m) Malfunction of monitoring equipment;
n) Malfunction of any surface equipment used for flow back operations;
o) Failure of leak detection monitoring equipment during the flow back process;
p) An occurrence of pollution, i.e., oil on the water;

q) Personal injury or fatality;

r) Onboard fire or explosion; and

s) Well control incident including a blowout.

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9 APPENDICES

9.1 APPENDIX A – Group 1: Hydrocarbon-Producing, US States with Well Stimulation-Specific Rules

9.1.1 Alabama

Regulatory Authority: State Oil and Gas Board of Alabama

Reference Source: State Oil and Gas Board of Alabama Administrative Code, Oil and Gas Report 1, Rules and Regulations Governing the Conservation of Oil and Gas in Alabama and Oil and Gas Laws of Alabama with Oil and Gas Board Forms

400-1-4-.07. Chemically Treating or Fracturing a Well.

Wells shall not be chemically treated or fractured until the approval of the Supervisor is obtained. Each well shall be treated or fractured in such manner as will not cause damage to the formation, result in water encroachment into the oil- or gas-bearing formation, or endanger freshwater-bearing strata. Necessary precautions shall be taken to prevent damage to the casing. Routine chemical treatments for corrosion control shall be excluded from this notice requirement. If chemical treating or fracturing results in irreparable damage to the well, the oil or gas-bearing formation or freshwater-bearing strata, then the well shall be properly plugged and abandoned.

400-1-9-.04. Hydraulic Fracturing

(1) Each formation shall be hydraulically fractured so as not to cause irreparable damage to the oil and gas well, or to adversely impact any fresh water supply well or any fresh water resources.

(2) A proposal to fracture a formation shall be accompanied by a check or bank draft in the amount of two-hundred fifty dollars ($250) payable to the State Treasurer, State of Alabama, which sum is fixed as the fee for each proposal; however, in no case shall the fee paid for concurrent hydraulic fracturing operations in a single well exceed seven-hundred fifty dollars ($750) regardless how many formations

are hydraulically fractured. Where the proposal to hydraulically fracture is associated with a horizontal well, then the fee shall be two-hundred fifty dollars ($250) for each segment or stage of the horizontal well in which a hydraulic fracturing operation is conducted; however, in no case shall the amount be over seven- hundred fifty dollars ($750) in connection with concurrent hydraulic fracturing operations in a single well. The fee shall be deposited into the Alabama State Oil and Gas Board Special Fund pursuant to Section 9-17-24 of the Code of Alabama (1975).

(3) A formation shall not be hydraulically fractured until approval of the Supervisor is obtained. In order to receive approval from the Supervisor, a proposal to fracture shall include the following:

(a) a wellbore schematic showing the specifications of the casing and cementing program, including pressure tests and the depth interval(s) and name(s) of formation(s) to be fractured;

(b) geophysical and cement bond logs;

(c) a program describing the proposed fracturing operation. Information to be considered shall include, but not be limited to, the maximum length and orientation of the fracture(s) to be propagated and the type fluids and materials that are to be utilized. Programs to hydraulically fracture shall be prepared by a person, or entity, familiar with the technicalities of fracturing formations in the area in which fracturing operations are proposed. The program filed with the Board shall identify the person, or entity, that has prepared the fracturing program and be accompanied by a letter from the operator stating its intended application. Recurrent filing of a fracturing program will not be necessary if such program has previously been submitted to the Supervisor and is directly applicable to the fracturing proposal under consideration. Modification(s) to a fracturing program that would alter the maximum length and orientation of the fracture(s) to be propagated, or the type fluids and material to be utilized, shall be submitted to the Supervisor prior to its implementation in the field;

(d) an inventory prepared by the operator identifying all fresh water supply wells within a one quarter- (1/4-) mile radius of the well to be fractured. Records of fresh water supply wells shall be used by the operator in delineating the construction and completion depths of such supply wells. The records of the Geological Survey of Alabama (GSA) shall be the primary source of information used in this evaluation process. Additionally, the operator shall conduct a field reconnaissance within a one quarter- (1/4-) mile radius of the subject well to determine the location of any additional fresh water supply wells that may not be identified in the previously described documents. If possible, construction information for such additional fresh water supply wells must be obtained. Consideration shall be given to the records of all fresh water supply wells available and the operator shall report the results of his findings to the Supervisor. Fracturing operations shall not be conducted if it is determined that any fresh water resources or any fresh water supply well located within a one quarter- (1/4-) mile radius of the subject well could be adversely impacted as a result of the fracturing operation; and

(e) a statement by the operator affirming to the Supervisor, in writing, that the well construction and pressure tests results, and geophysical and cement bond logs, have been evaluated and that the results of this evaluation indicate that the proposed hydraulic fracturing operations can be conducted without adverse impact on any fresh water supply wells or any fresh water resources.

In reviewing a proposal for hydraulic fracturing, the Supervisor shall consider:

1. whether the proposed hydraulic fracturing operation ensures that the formation to be fractured lies beneath an impervious stratum;
2. whether the fracture fluid to be utilized will remain in the formation to be fractured; and
3. whether the casing is effectively cemented in place.

(4) Diesel oil or fuel is prohibited in any fluid mixture used in the hydraulic fracturing of a formation.

(5) The Supervisor may request the submittal of additional information in order to clarify a proposal to hydraulically fracture a formation.

(6) The operator shall maintain all records associated with each proposal approved by the Supervisor and implemented by the operator to hydraulically fracture formations until such time that the subject

well has been plugged for permanent abandonment, but not less than three (3) years following completion of the fracturing operation. Upon request, copies of these records shall be made available to the Supervisor.

(7) In order to provide adequate disclosure of well stimulation fluids utilized in a hydraulic fracturing operation,

(a) The operator shall provide to the Board:

1. a description of the fracture fluid identified by additive, e.g., acid, proppant, surfactant, and
2. the name of the chemical compound and the Chemical Abstracts Service Registry number, if such registry number exists, as published by the Chemical Abstracts Service, a division of the American Chemical Society, for each constituent added to the base fluid, and
3. the operator is not required to disclose information that is deemed to be a trade secret. However, information deemed to be a trade secret shall be disclosed as necessary for proper medical diagnosis and treatment or for spill response.

(b) Within thirty (30) days after the fracturing of a well, the operator shall post the information to the Frac Focus website.

9.1.2 Alaska

Regulatory Authority: Alaska Oil and Gas Conservation Commission

Reference Source: Alaska Administrative Code

Note: The following regulations are proposed but not yet ratified by the Alaska Legislature

20 AAC 25.283. Hydraulic Fracturing.

(a) Prior to hydraulic fracturing, the operator must submit an Application For Sundry Approvals (Form 10-403) under 20 AAC 25.280. Unless modified or altered by pool rules established under 20 AAC 25.520, the application shall include;

(1) an affidavit showing that all owners, landowners, surface owners, and operators within a one-half mile radius of the current or proposed wellbore trajectory have been provided notice of operations. The notification will state that upon request, a complete copy of the application is available from the operator, and will include the operator contact information;

(2) a plat showing the well location and identifying any water wells located within a one- half mile radius of the well's surface location and further identifying any well penetrations (all well types) within one-half mile of the current or proposed wellbore trajectory and fracturing interval and the sources of the information used in identifying such wells;

(3) identification of freshwater aquifers and the geologic name and depth (MD and TVD) to the bottom of all freshwater aquifers within the one-half mile radius;

(4) a plan for baseline water sampling of water wells prior to hydraulic fracturing. Water sampling consists of collection of baseline water data pre-fracture, within a one-half mile radius of the current or proposed wellbore trajectory. The operator shall detail the well selection process for identifying wells to sample. If surface owners do not grant permission for baseline sampling or disclosure of results, the operator shall document the reasonable and good faith efforts taken to secure such permission. Surface owners that deny permission for pre-fracture

sampling or disclosure of results are not required to be included in post fracture water sampling as required by subsection (j). The sample parameters shall include pH; Alkalinity (total bicarbonate and carbonate as $CaCO_3$); specific conductance; bacteria presence (iron related, sulfate reducing, slime forming); arsenic; barium; bicarbonate; boron; bromide; cadmium; calcium; chloride; chromium; fluoride; hydroxide; iodide; iron; lithium; magnesium; manganese; nitrate and nitrite as N; phosphorus; potassium; radium (measured by radium 226 and 228); selenium; silicon; sodium; strontium; sulfate; Total Dissolved Solids; Total Petroleum Hydrocarbons (TPH) and BTEX/GRO/DRO (Benzene, Toluene, Ethylbenzene, Xylene – by method EPA 5035/ SW-846 8260B or C, Gasoline Range Organics – by method EPA 5035/ SW- 846 8015C or D or AK 101, Diesel Range Organics – by method EPA SW-846 8015C or D with silica gel cleanup or AK 102); PAH's (Polynuclear Aromatic Hydrocarbons including benzo(a)pyrene); Dissolved Methane, Dissolved Ethane, and Dissolved Propane (by method RSK-175). Field observations such as odor, water color, sediment, bubbles, and effervescence shall also be documented. If free gas or a dissolved methane concentration greater than 1.0 milligram per liter (mg/l) is detected in a water sample, gas compositional analysis and stable isotope analysis of the methane (carbon and hydrogen – 12C, 13C, 1H, and 2H) shall be performed to determine gas type. The operator shall notify the commission, the Alaska Department of Environmental Conservation (ADEC), and the surface owner within 24 hours if;

(A) the test results indicate thermogenic or a mixture of thermogenic and biogenic gas;

(B) the methane concentration increases by more than 5.0 mg/l between

sampling periods should multiple samples be required;

(C) the methane concentration is detected at or above 10 mg/l; or

(D) BTEX compounds, TPH, GRO, or DRO are detected.

Current applicable EPA or ADEC-approved sample custody and collection protocols and analytical methods must be used and analyses must be performed by laboratories that maintain nationally or State of Alaska accredited programs. Copies of all test results, analytical results and sample locations shall be provided to the commission and to ADEC in printed form and in an electronic data deliverable format that is acceptable to the commission within 90 days of collecting the samples;

(5) detailed casing and cementing information;

(6) an assessment of each casing and cementing operation performed to construct or repair the well with sufficient supporting information, including cement evaluation logs and other evaluation logs approved by the commission, to demonstrate that casing is cemented below the base of the lowermost freshwater aquifer and according to 20 AAC 25.030 and that all hydrocarbon zones penetrated by the well are isolated;

(7) pressure test information if available and plans to pressure test the casings and tubing installed in the well;

(8) accurate pressure ratings and schematics for the wellbore, wellhead, BOPE, and treating head;

(9) data for the fracturing zone and confining zones including lithologic description, geological name, measured depth (MD) and true vertical depth (TVD), measured and true vertical thickness, and estimated fracture pressures for the fracturing zone and confining zones;

(10) the location, orientation, and a report on the mechanical condition of each well that may transect the confining zones and information sufficient to support a determination that such wells will not interfere with containment of the hydraulic fracturing fluid within the one-half mile radius of the proposed wellbore trajectory;

(11) the location, orientation, and geological data of known or suspected faults and fractures that may transect the confining zones, and information sufficient to support a determination that any such faults and fractures will not interfere with containment of the hydraulic fracturing fluid within the one-half mile radius of the proposed wellbore trajectory;

(12) a detailed copy of the proposed hydraulic fracturing program including, but not limited to, the pumping procedure by stage where applicable, with a chemical disclosure based on the total amounts and volumes per well including;

(A) the estimated total volumes planned;

(B) the trade name, generic name, and purpose of all base fluid(s) and additives to be used. The estimated or maximum rate or concentration of each additive shall be provided in appropriate measurement units;

(C) the chemical ingredient name and the Chemical Abstracts Service (CAS) Registry number, as published by the Chemical Abstracts Service (a division of the American Chemical Society, see www.cas.org), for each base fluid and each additive used. The actual or maximum concentration of each chemical ingredient in each base fluid and additive used shall be provided in percent by mass. In addition, the actual or maximum concentration of each chemical ingredient in the hydraulic fracturing fluid shall be provided in percent by mass. Freeze-protect fluids pumped before and/or after hydraulic fracturing should not be included;

(D) the estimated weight or volume of inert substances, including proppants and other substances injected;

(E) the maximum anticipated treating pressure and information sufficient to support a determination that the well is appropriately constructed for the proposed hydraulic fracturing program; and

(F) the designed height and length of the proposed fracture(s), including the calculated MD and TVD of the top of the fracture(s) accompanied by a description of the methods and assumptions used to determine designed fracture height and length.

(13) a detailed description of the plan for post fracture wellbore cleanup and fluid recovery through to production operations.

(b) When hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to 110% of the maximum anticipated pressure differential to which the casing may be subjected. If the casing fails the pressure test it must be repaired or the operator must use a temporary casing string (fracturing string).

(c) When hydraulic fracturing through a fracturing string, the fracturing string must be stung into a liner or run on a packer set not less than 100 ft MD below the cement top of the production or intermediate casing and tested to not less than 110% of the maximum anticipated pressure differential to which the fracturing string may be subjected.

(d) A pressure relief valve(s) must be installed on the treating lines between pumps and wellhead to limit the line pressure to the test pressure determined in (a)12 (E) of this section; the well must be equipped with a remotely controlled shut-in device unless the operator requests and obtains a waiver from the commission.

(e) The placement of all hydraulic fracturing fluids shall be confined to the approved formations during hydraulic fracturing.

(f) If the surface casing annulus is not open to atmospheric pressure, then the surface casing pressures shall be monitored with a gauge and pressure relief device while hydraulic fracturing operations are in progress; the annular space between the fracturing string and the intermediate or production casing must be continuously monitored; the pressure in such annular space may not exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.

(g) During hydraulic fracturing operations, all annulus pressures must be continuously monitored and recorded. If at any time during hydraulic fracturing operations the annulus pressure increases more than 500 psig above those anticipated increases caused by pressure or thermal transfer, the operator must notify the commission as soon as practicable, but no later than twenty-four (24) hours following the incident and shall implement corrective action or increased surveillance as the commission requires. Within fifteen (15) days after the occurrence, the operator shall submit a Report of Sundry Well Operations Form 10-404 giving all details, including corrective actions taken.

(h) The operator shall file with the commission, within 30 days after completion of hydraulic fracturing operations, on a Report of Sundry Well Operations (Form 10-404), a complete record of the work performed and the tests conducted, and a summary of daily well operations as described in 20 AAC 25.070(3). The operator shall also file with the commission a copy of the daily record required by 20 AAC 25.070(1).

(1) For each hydraulic fracturing interval, the information will include;

(A) measured and true vertical depth of the perforations/sleeves for the actual treated interval;

(B) the amount and type(s) of base fluid(s) and additives pumped during each stage;

(2) For all hydraulic fracturing treatments contained within the Sundry Report, the information will include the total amount and type(s) of base fluid(s) and additives pumped including;

(A) a description of the hydraulic fracturing fluid pumped identified by base fluid(s) and additives including trade name, supplier, and a brief description of the purpose (e.g., acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, de-emulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant); and

(B) the chemical ingredient name and the CAS registry number, as published by the Chemical Abstracts Service (a division of the American Chemical Society, see www.cas.org), for each base fluid and each additive used. The actual or maximum concentration of each chemical ingredient in each base fluid and additive used shall be provided in percent by mass. In addition, the actual or maximum concentration of each chemical ingredient in the hydraulic fracturing fluid shall be provided in percent by mass. Freeze-protect fluids pumped before and/or after hydraulic fracturing should not be included;

(i) Prior to the submission of Form 10-404 under subsection (h), the operator must post the information required by the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing web site (www.fracfocus.org). A printed copy and electronic copy of this information in a format acceptable to the commission shall be filed as an attachment with the Form 10-404.

(j) The commission may require water sampling of water wells post hydraulic fracturing. If required, water sampling may consist of collection of water data post-fracture, in accordance with a sampling and monitoring plan approved by the commission, within a one-half mile radius of the wellbore trajectory. The operator shall detail the well selection process for identifying wells to sample. Methods, parameters, and analysis are to be similar to subsection (a)(4) as required by the commission.

(k) Any information required to be filed under 20 AAC 25.283 which the filing party claims to be a confidential trade secret shall be separately filed in an envelope clearly marked confidential along with a list of the documents which are nondisclosable as trade secrets, the specific legal authority and specific facts supporting nondisclosure in accordance with 2 AAC 96.325(a)(2) (privilege log). The commission will review all such information filed, but will maintain such information as confidential under the Public Records Act. Upon receipt of a request for disclosure of such information under Alaska's Public Records Act, AS 40.25.100, et seq., the commission will promptly forward the Public Records Act request to the party claiming confidentiality. Within the time allowed to respond under the Public Records Act, the commission will forward the privilege log to the requesting party. Should the claim of privilege be challenged in Superior Court, the commission will file the privilege log with the court and promptly notify the party claiming confidentiality of the Superior Court action.

(l) Upon written request of the operator, the commission may modify a deadline in this section upon a showing of good cause, approve a variance from any other requirement of this section if the variance provides at least an equally effective means of complying with the requirement, or approve a waiver of a requirement of this section if the waiver will not promote waste, is based on sound engineering and geoscience principles, will not jeopardize the ultimate recovery of hydrocarbons, will not jeopardize correlative rights, and will not result in an increased risk to health, safety, or the environment, including freshwater.

9.1.3 Arizona

Regulatory Authority: Arizona Oil and Gas Conservation Commission

Reference Source: Arizona Administrative Code, Title 12. Natural Resources, Chapter 7. Oil and Gas Conservation Commission

R12-7-122. Recompletion and Routine Maintenance Operations

C. Written approval from the Commission is not required on acidizing, fracturing, and reperforating, or other routine well operations designed to restore or maintain production.

R12-7-117. Artificial Stimulation of Oil and Gas Wells

A. An operator shall report the artificial stimulation of any well to the Commission in writing within 15 days of the stimulation showing the type of stimulation, the amounts and types of materials used, stimulation pressures applied, and the flow and pressure results before and after stimulation.

B. If the artificial stimulation of a well results in any damage to the producing formation, a freshwater formation, casing, or casing seat that permits communication between fluid-bearing zones, the operator shall immediately notify the Commission and proceed with diligence to correct the damage. If the artificial stimulation results in irreparable damage to the well, the operator shall plug and abandon the well pursuant to R12-7- 127.

9.1.4 Arkansas

Regulatory Authority: Arkansas Oil and Gas Commission

Reference Source: General Rules and Regulations as of August 01, 2014

Rule B-19. Requirements for Well Completion Utilizing Fracturing Stimulation

(b) The provisions of this Rule shall apply to all new wells for which an initial drilling permit is issued on or after the effective date of this Rule.

(c) Persons applying for a permit to drill shall indicate on the initial drilling application the intent to perform Hydraulic Fracturing Treatment operations and provide the information required in accordance with subparagraph d) below. If the intent to fracture stimulate a well was not provided at the time of the initial drilling application, a Permit Holder desiring to perform Hydraulic Fracturing Treatment operations shall send the information required in accordance with subparagraph d) below via e-mail, fax or mail to the AOGC office where the initial drilling permit was issued, prior to commencement of Hydraulic Fracturing Treatment operations.

d) The application described in subparagraph c) above shall include:

1) The following information on the proposed casing program, demonstrating that the well will have steel alloy casing designed to withstand the anticipated maximum pressures to which the casing will be subjected in the well:

A) Whether the well will be a vertical well, a directional well, or a horizontal well; and

B) The estimated true vertical and measured production casing setting depths; and

C) The casing grade and minimum internal yield pressure for the production casing proposed to be used in the well.

2) The following information demonstrating that the well will have sufficient cement volume and integrity to prohibit movement of fracture fluids up-hole into the various casing or well bore annuli:

A) The proposed cement formulation(s)' minimum compressive strength; and

B) The estimated top of cement for the production casing string.

3) The anticipated surface treating pressure range for the proposed Hydraulic Fracturing Treatment program. The production casing described in subparagraph d) 1) above shall be sufficient to contain the maximum anticipated treating pressure of the Hydraulic Fracturing Treatment, which shall not exceed 80% of the minimum internal yield pressure for such production casing.

e) Surface casing in the well in which the proposed Hydraulic Fracturing Treatment will occur shall be set, and cemented to the surface, to a depth in accordance with General Rule B-15, and have sufficient internal yield pressure to withstand the anticipated maximum pressures to which the casing will be subjected in the well. If during the drilling of the surface portion of the well, and prior to setting surface casing, a freshwater flow is encountered, or the Permit Holder gains knowledge that freshwater will be encountered, from a deeper zone than was specified on the permit to drill, surface casing shall be set and cemented at least one hundred (100) feet below the deepest encountered freshwater zone.

f) If during the setting and cementing of production and/or any intermediate casings the cement program does not occur as submitted in accordance with this Rule, and would cause a reasonably prudent Permit Holder to question the integrity of the cementing program with respect to isolating the zone of Hydraulic Fracturing Treatment from movement of fracture fluids up-hole into the various casing or well bore annuli, the Permit Holder shall immediately notify the Director, or his designee, in writing as soon as practicable, but not more than twenty-four (24) hours after the event. In reviewing the report, the Director, or his designee, may require a bond log or other cement evaluation tool to document cement integrity and require additional cementing operations or other appropriate well workover efforts necessary to correct any cement deficiencies prior to initiating any Hydraulic Fracturing Treatments in the well.

g) The Permit Holder shall monitor all casing annuli that would be diagnostic as to a potential loss of well bore integrity during the Hydraulic Fracturing Treatment. The Permit Holder shall establish methods to timely relieve any excessive pressures to avoid the loss of surface casing integrity.

h) The Permit Holder must provide written notice to the Director, or his designee, of (i) any change in surface casing annulus pressure that would indicate movement of fluids into the annulus, or (ii) a pressure that exceeds the rated minimum internal yield pressure on any casing string in communication with the Hydraulic Fracturing Treatment. This written notice shall be delivered as soon as possible after the event, but not more than twenty-four (24) hours after the event. Following notification and any request for additional information, the Director, or his designee, may request additional documentation or well tests to determine if the Hydraulic Fracturing Treatment potentially endangered any freshwater zones. The Director, or his designee, may require appropriate additional cementing operations, or other well workover efforts to correct any well failure. Pending completion of required operations or efforts, the Director, or his designee, may order the cessation of further Hydraulic Fracturing Treatment and/or other well operations. The Director shall report any such incident to the Commission at its next regularly scheduled hearing, and the Commission may take such further action as it deems necessary and appropriate under the circumstances.

i) All non-exempt RCRA materials and fluids used on-site in the Hydraulic Fracturing Treatment shall be handled and stored in accordance with ADEQ requirements and any spills of these materials and fluids on-site or off-site shall be reported to ADEQ in accordance with applicable ADEQ requirements. All RCRA exempt materials and fluids used on-site in the Hydraulic Fracturing Treatment shall be contained in leak free tanks or other containment vessels. Any on-site spill of these materials or fluids shall be immediately contained, remediation efforts shall be commenced as soon as practical, and the incident shall be reported to the Director, or his designee, within twenty-four (24) hours.

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j) All Hydraulic Fracturing Treatment flow back fluids shall be handled, transported, stored, disposed, or recycled for re-use in accordance with the applicable provisions of General Rule B-17, General Rule E-3 and General Rule H-1, H-2 and H-3.

k) Following completion of the Hydraulic Fracturing Treatment, the Permit Holder shall, for purposes of disclosure, report detailed information to the Director, or his designee, of the Hydraulic Fracturing Treatment in the manner customarily reported or presented to the Permit Holder, within the time period specified in General Rule B-5, as follows:

1) The maximum pump pressure measured at the surface during each stage of the Hydraulic Fracturing Treatment; and

2) The types and volumes of the Hydraulic Fracturing Fluid and proppant used for each stage of the Hydraulic Fracturing Treatment; and

3) The calculated fracture height as designed to be achieved during the Hydraulic Fracturing Treatment and the estimated TVD to the top of the fracture; and

4) A list of all Additives used during the Hydraulic Fracturing Treatment specified by general type, such as acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, scale inhibitor, proppant and surfactant; and

5) The names of all specific Additives for each Additive type, specified in subparagraph k) 4) above, utilized during the Hydraulic Fracturing Treatment and the actual rate or concentration for each such Additive expressed as pounds per thousand gallons or gallons per thousand gallons additionally, the Additives are to be expressed as a percent by volume of the total Hydraulic Fracturing Fluids and Additives; and

6) The Permit Holder shall supply field service company tickets (excluding pricing) and reports regarding the Hydraulic Fracturing Treatment, as used in the normal course of business to satisfy some or all of the foregoing information requirements; and

7) The Permit Holder shall supply all information received from the person performing the Hydraulic Fracturing Treatment specified in subparagraph l) 4) below.

8) If the Permit Holder causes any Additives to be utilized during the Hydraulic Fracturing Treatment not otherwise disclosed by the person performing the Hydraulic Fracturing Treatment, the Permit Holder shall disclose a list of all Chemical Constituents and associated CAS numbers contained in all such Additives; provided, however, in those limited situations where the specific identity of any such Chemical Constituent and associated CAS number is entitled to be withheld as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042, the Permit Holder shall (i) submit to the Director a claim of entitlement to have the identity of such Chemical Constituent withheld as a trade secret, and (ii) provide the Director with the Chemical Family associated with such Chemical Constituent. The identity of any Chemical Constituent that qualifies as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042 shall be held confidential by the Director.

9) Nothing in subparagraph k) 8) above shall authorize any person to withhold information which is required by state or federal law to be provided to a health care professional, a doctor, or a nurse. All information required by a health care professional, a doctor, or a nurse shall be supplied, immediately upon request, by the person performing the Hydraulic Fracturing Treatment, directly to the requesting health care professional, doctor, or nurse, including the percent by volume of the Chemical Constituents (and associated CAS numbers) of the total Hydraulic Fracturing Fluids and Additives.

l) Any person performing Hydraulic Fracturing Treatments within the State of Arkansas shall:

1) Be authorized to do business in the State of Arkansas; and

2) Be required to file Organization Reports in accordance with General Rule B-13, and include the length of time the entity has been in the business of performing Hydraulic Fracturing Treatments; and

3) Disclose to the Director, or his designee, and maintain separate master lists of:

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A) All Hydraulic Fracturing Fluids to be utilized during any Hydraulic Fracturing Treatment within the State of Arkansas; and

B) All Additives to be utilized during any Hydraulic Fracturing Treatment within the State of Arkansas; and

C) All Chemical Constituents and associated CAS numbers to be utilized in any Hydraulic Fracturing Treatment within the State of Arkansas; provided, however, in those limited situations where the specific identity of any such Chemical Constituent and associated CAS number is entitled to be withheld as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042, the person performing the Hydraulic Fracturing Treatment shall (i) submit to the Director a claim of entitlement to have the identity of such Chemical Constituent withheld as a trade secret, and (ii) provide the Director with the Chemical Family associated with such Chemical Constituent. The identity of any Chemical Constituent that qualifies as a trade secret under the criteria set forth in subsection (a)(2) of 42 U.S.C. § 11042 shall be held confidential by the Director; and

4) Provide to the Permit Holder for each well that such person performs a Hydraulic Fracturing Treatment, lists of:

A) The Hydraulic Fracturing Fluids utilized during the Hydraulic Fracturing Treatment; and

B) The Additives utilized during the Hydraulic Fracturing Treatment, and the actual rate or concentration for each such Additive utilized, expressed as pounds per thousand gallons or gallons per thousand gallons; additionally, the Additives are to be expressed as percent by volume of the total Hydraulic Fracturing Fluids and Additives, so that the Permit Holder may comply with its obligations under subparagraph k) above; and

C) All Chemical Constituents and associated CAS numbers utilized during the Hydraulic Fracturing Treatment; unless the specific identity of any such Chemical Constituent and associated CAS number is entitled to be withheld as a trade secret in accordance with subparagraph l) 3) c) above.

5) Nothing in subparagraphs l) 3) c) or l) 4) c) above shall authorize any person to withhold information which is required by state or federal law to be provided to a health care professional, a doctor, or a nurse. All information required by a health care professional, a doctor, or a nurse shall be supplied, immediately upon request, by the person performing the Hydraulic Fracturing Treatment, directly to the requesting health care professional, doctor, or nurse, including the percent by volume of the Chemical Constituents (and associated CAS numbers) of the total Hydraulic Fracturing Fluids and Additives.

m) No Permit Holder shall utilize the services of another person to perform a Hydraulic Fracturing Treatment unless the person performing a Hydraulic Fracturing Treatment is in compliance with subparagraph l) above.

9.1.5 California

Regulatory Authority: California Department of Conservation

Reference Source: Statues and Regulations for Conservation of Oil, Gas, and Geothermal Resources

Article 4. Well Stimulation Treatments

§ 1780. Purpose, Scope, and Applicability [Effective until July 1, 2015]

(a) The purpose of this article is to set forth regulations governing well stimulation treatments, as defined in Section 1761, subdivision (a)(1), except that the requirements of this article do not apply to acid matrix stimulation treatments that use an acid concentration of 7% or less. Nor is an operator required to obtain a permit under Public Resources Code section 3160, subdivision (d), prior to performing an acid matrix stimulation treatment that uses an acid concentration of 7% or less.

(b) Well stimulation treatments are not subsurface injection or disposal projects and are not subject to Sections 1724.6 through 1724.10. This article does not apply to underground injection projects.

(c) For purposes of this article, a well stimulation treatment commences when well stimulation fluid is pumped into the well, and ends when the well stimulation treatment equipment is disconnected from the well.

§ 1780. Purpose, Scope, and Applicability [Effective July 1, 2015]

(a) The purpose of this article is to set forth regulations governing well stimulation treatments, as defined in Section 1761(a)(1), for wells located both onshore and offshore.

(b) Well stimulation treatments are not subsurface injection or disposal projects and are not subject to Sections 1724.6 through 1724.10 or Sections 1748 through 1748.3. This article does not apply to underground injection projects. If well stimulation treatment is done on a well that is part of an underground injection project, then regulations regarding well stimulation treatment apply to the well stimulation treatment and regulations regarding underground injection projects apply to the underground injection project operations.

(c) For purposes of this article, a well stimulation treatment commences when well stimulation fluid is pumped into the well, and ends when the well stimulation treatment equipment is disconnected from the well.

§ 1781. Definitions [Effective until July 1, 2015]

The following definition shall govern this article:

(a) “Acid matrix stimulation treatment” means an acid treatment conducted at pressures lower than the applied pressure necessary to fracture the underground geologic formation.

(b) “Acid well stimulation treatment” means a well stimulation treatment that uses, in whole or in part, the application of one or more acids to the well or underground geologic formation. The acid well stimulation treatment may be at any applied pressure and may be used in combination with hydraulic fracturing treatments or other well stimulation treatments. Acid well stimulation treatments include acid matrix stimulation treatments and acid fracturing treatments.

(c) “Acid stimulation treatment fluid” means one or more base fluids mixed with physical and chemical additives for the purpose of performing an acid well stimulation treatment.

(d) “Additive” means a substance or combination of substances added to a base fluid for purposes of preparing well stimulation treatment fluid, including, but not limited to, acid stimulation treatment fluid and hydraulic fracturing fluid. An additive may serve additional purposes beyond the transmission of hydraulic pressure to the geologic formation. An additive may be of any phase and may include proppants.

(e) “Base fluid” means the continuous phase fluid used in the makeup of a well stimulation treatment fluid. The continuous phase fluid may include, but is not limited to, water, and may be a liquid or a hydro- carbon or nonhydrocarbon gas. A well stimulation treatment may use more than one base fluid.

(f) “Chemical Disclosure Registry” means the chemical registry Internet Web site known as fracfocus.org developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

(g) “Flowback fluid” means the fluid recovered from the treated well before the commencement of oil and gas production from that well following a well stimulation treatment. The flowback fluid may include materials of any phase.

(h) “Hydraulic fracturing” means a well stimulation treatment that, in whole or in part, includes the pressurized injection of hydraulic fracturing fluid or fluids into an underground geologic formation in order to fracture or with intent to fracture the formation, thereby causing or enhancing, for the purposes of this article, the production of oil or gas from a well.

(i) “Hydraulic fracturing fluid” means one or more base fluids mixed with physical and chemical additives for the purpose of hydraulic fracturing.

(j) “Proppants” means materials inserted or injected into the underground geologic formation that are intended to prevent fractures from closing.

(k) “Protected water” means water outside of a hydrocarbon zone that contains no more than 10,000 mg/l total dissolved solids unless the water has been determined to be an exempt aquifer pursuant to the Code of Federal Regulations, title 40, part 146.4.

(l) “Regional Water Board” means the Regional Water Quality Control Board with jurisdiction over the location of a well subject to well stimulation treatment.

(m) “Surface property owner” means the owner of real property as shown on the latest equalized assessment roll or, if more recent information than the information contained on the assessment roll is avail- able, the owner of record according to the county assessor or tax collector.

(n) “Well stimulation treatment fluid” means a base fluid mixed with physical and chemical additives, which may include acid, for the purpose of a well stimulation treatment. A well stimulation treatment may include more than one well stimulation treatment fluid. Well stimulation treatment fluids include, but are not limited to, hydraulic fracturing fluids and acid stimulation treatment fluids.

§ 1781. Definitions [Effective July 1, 2015]

The following definitions shall govern this article:

(a) “Acid fracturing” means a well stimulation treatment that, in whole or in part, includes the pressurized injection of acid into an underground geologic formation in order to fracture the formation, thereby causing or enhancing, for the purposes of this division, the production of oil or gas from a well.

(b) “Acid matrix stimulation treatment” means an acid treatment conducted at pressures lower than the applied pressure necessary to fracture the underground geologic formation.

(c) “Acid well stimulation treatment” means a well stimulation treatment that uses, in whole or in part, the application of one or more acids to the well or underground geologic formation. The acid well stimulation treatment may be at any applied pressure and may be used in combination with hydraulic fracturing treatments or other well stimulation treatments. Acid well stimulation treatments include acid matrix stimulation treatments and acid fracturing treatments.

(d) “Acid stimulation treatment fluid” means one or more base fluids mixed with physical and chemical additives for the purpose of performing an acid well stimulation treatment.

(e) “Additive” means a substance or combination of substances added to a base fluid for purposes of preparing well stimulation treatment fluid, including, but not limited to, acid stimulation treatment fluid and hydraulic fracturing fluid. An additive may serve additional purposes beyond the transmission of hydraulic pressure to the geologic formation. An additive may be of any phase and may include proppants.

(f) “ADSA” or “axial dimensional stimulation area” means the estimated axial dimensions, ex- pressed as maximum length, width, height, and azimuth, of the area(s) stimulated by a well stimulation treatment.

(g) “Base fluid” means the continuous phase fluid used in the makeup of a well stimulation treatment fluid. The continuous phase fluid may include, but is not limited to, water, and may be a liquid or a hydro- carbon or nonhydrocarbon gas. A well stimulation treatment may use more than one base fluid.

(h) “Chemical Disclosure Registry” means the chemical registry Internet Web site known as fracfocus.org developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Com- mission.

(i) “Designated Contractor for Water Sampling” means an independent third-party person or entity designated by the State Water Board to sample water well and surface water in accordance with Public Re- sources Code section 3160, subdivision (d)(7).

(j) “Flowback fluid” means the fluid recovered from the treated well before the commencement of oil and gas production from that well following a well stimulation treatment. The flowback fluid may include materials of any phase.

(k) “Hydraulic fracturing” means a well stimulation treatment that, in whole or in part, includes the pressurized injection of hydraulic fracturing fluid into an underground geologic formation in order to fracture the formation, thereby causing or enhancing, for the purposes of this division, the production of oil or gas from a well.

(l) “Hydraulic fracturing fluid” means one or more base fluids mixed with physical and chemical additives for the purpose of hydraulic fracturing.

(m) “Independent third party” means a person or entity responsible to an operator, but who is not an employee of the operator, is not under the ownership or direct control of the operator, and does not have a direct financial interest in the production activities of the operator.

(n) “Proppants” means materials inserted or injected into the underground geologic formation that are intended to prevent fractures from closing.

(o) “Regional Water Board” means the Regional Water Quality Control Board with jurisdiction over the location of a well subject to well stimulation treatment.

(p) “State Water Board” means the State Water Resources Control Board.

(q) “Surface property owner” means the owner of real property as shown on the latest equalized assessment roll or, if more recent information than the information contained on the assessment roll is avail- able, the owner of record according to the county assessor or tax collector.

(r) “Tenant” means a person or entity with a possessory interest in and right to occupy a legally recognized parcel, or portion thereof.

(s) “Well stimulation treatment fluid” means a base fluid mixed with physical and chemical additives, which may include acid, for the purpose of a well stimulation treatment. A well stimulation treatment may include more than one well stimulation treatment fluid. Well stimulation treatment fluids include, but are not limited to, hydraulic fracturing fluids and acid stimulation treatment fluids.

§ 1782. General Well Stimulation Treatment Requirements [Effective until July 1, 2015]

(a) When a well stimulation treatment is performed, the operator shall adhere to all of the following requirements:

(1) Casing shall be sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times during well stimulation treatment.

(2) All potentially productive zones, zones capable of over-pressurizing the surface casing annulus, or corrosive zones shall be isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing.

(3) The wellbore's mechanical integrity shall be tested and maintained and all cemented casing strings and all tubing strings utilized in the well stimulation treatment operations shall be pressure tested prior to well stimulation treatment. No casing or tubing shall be used unless it has been successfully tested.

(4) All surface equipment to be utilized for well stimulation treatment shall be rigged up as designed. The pump, and all equipment downstream from the pump, shall be pressure tested prior to well stimulation treatment.

(5) The well stimulation treatment fluid shall not be of a concentration level that will damage the well casing, tubing, cement, or other well equipment, or would otherwise cause degradation of the well's mechanical integrity during the treatment process.

(6) The operator's Spill Contingency Plan shall address handling of well stimulation fluid and additives.

§ 1782. General Well Stimulation Treatment Requirements [Effective July 1, 2015]

(a) When a well stimulation treatment is performed, the operator shall ensure that all of the following conditions are continuously met:

(1) Casing is sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times;

(2) Geologic and hydrologic isolation of the oil and gas formation are maintained during and following the well stimulation treatment;

(3) All potentially productive zones, zones capable of over-pressurizing the surface casing annulus, or corrosive zones be isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing;

(4) All well stimulation treatment fluids are directed into the zone(s) of interest;

(5) The wellbore's mechanical integrity is tested and maintained;

(6) The well stimulation treatment fluids used are of known quantity and description for reporting and disclosure as required pursuant to this article; and

(7) The well stimulation treatment will not damage the well casing, tubing, cement, or other well equipment, or would not otherwise cause degradation of the well's mechanical integrity during the treatment process;

(8) Well breach occurring during well stimulation treatment will be reported as required in Section 1785, subdivision (d); and

(9) Well stimulation treatment operations are conducted in compliance with all applicable requirements of the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, the Air Quality Management District or Air Pollution Control District, the Certified Unified Program Agency, and any other local agencies with jurisdiction over the location of the well stimulation activities.

(b) In addition to specific methods set forth in these regulations, to achieve the objectives of this section, the operator shall follow all applicable well construction requirements, use good engineering practices, and employ best industry standards.

(c) The operator shall terminate well stimulation treatment as soon as it is safe to do so after it determines, or is informed by the Division, that any of the conditions of subdivision (a) are not being met.

§ 1783. Written Notice of Well Stimulation Treatment [Effective until July 1, 2015]

(a) At least 10 days in advance of commencing a well stimulation treatment, the operator shall submit written notification to the Division that includes all of the information and certifications listed in Section 1783.1. The written notification shall be submitted on the Interim Well Stimulation Treatment Notice form (7/14 version), hereby incorporated by reference, and signed by an authorized representative of the operator with basis of knowledge of all of the information and certifications provided. The Interim Well Stimulation Treatment Notice form shall be submitted to the Division in an electronic format, directed to the email ad- dress “NoticeWST@conservation.ca.gov”.

(b) Well stimulation treatment shall not commence unless the Division has reviewed the Interim Well Stimulation Treatment Notice form and approved the form as complete. As directed in Public Resources Code section 3161, the Division must allow, and will allow, well stimulation to proceed if the operator has provided all of the required information and certifications.

(c) The operator shall notify the Division at least 72 hours prior to commencing well stimulation so that Division staff may witness. Three hours prior to commencing, the operator shall confirm with the Division that the well stimulation treatment is proceeding.

§ 1783. Application for Permit to Perform Well Stimulation Treatment [Effective July 1, 2015]

(a) A well stimulation treatment or repeat well stimulation treatment shall not commence without a valid permit approved by the Division and shall be done in accordance with the conditions of the Division's approval. All well stimulation treatment permits approved by the Division shall include the condition that the well stimulation treatment shall not commence until the State Water Board or the Regional Water Board has provided written approval that the well stimulation treatment is covered under Water Code section 10783.

(b) An application for a permit to conduct well stimulation operations shall include all of the information listed in Section 1783.1 and shall be submitted electronically to the Division on a digital form specified by the Division and available on the Division's public internet Web site at http://www.conservation. ca.gov/DOG/Pages/Index.aspx.

(c) Upon receipt of a complete application for a permit to conduct well stimulation treatment, the Division will provide a copy of the permit application, including information in the application designated as trade secret or confidential, to the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, and the local air district where the well stimulation treatment may occur, provided that the manner and timing of providing copies of permit applications has been specified in a written agreement between the Division and the receiving agency.

(d) The operator shall notify the Division at least 72 hours prior to commencing well stimulation so that Division staff may witness. Between three and fifteen hours prior to commencing, the operator shall confirm with the Division that the well stimulation treatment is proceeding. Upon receipt of 72-hour notice from an operator, the Division will relay the notice to the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, and the local air district where the well stimulation treatment may occur, provided that the manner and timing of relaying the notice has been specified in a written agreement between the Division and the receiving agency.

(e) If a well is drilled, redrilled, or reworked after the Division approves a permit for a well stimulation treatment on the well, then, when providing the 72-hour notice under subdivision (d), the operator shall indicate what, if any, variance there was from the original notice of intent to drill, redrill, or rework the well. Authority: Sections 3013 and 3160, Public Resources Code. Reference: Sections 3106 and 3160, Public Resources Code

§ 1783.1. Contents of Interim Well Stimulation Treatment Notice [Effective until July 1, 2015]

(a) Written notification of a well stimulation treatment shall include the following information:

(1) Operator's name;

(2) Name and telephone number of person filing the form;

(3) Lease name and number of the well;

(4) Location of the well, submitted as a non-projected, Latitude Longitude, in the General Coordinate System (GCS) NAD83.

(5) API number assigned to the well by the Division;

(6) Name of the oil field;

(7) County in which the well is located;

(8) The time period during which the well stimulation treatment is planned to occur.

(9) For directionally drilled wells, the proposed coordinates (from surface location), the true vertical depth at total depth, and the wellbore path; and

(10) The planned location of the well stimulation treatment on the well bore, the estimated length, height, and direction of the induced fractures or other planned modification, if any.

(11) Whether the Division has made a determination that the well subject to well stimulation treatment is a confidential well under Public Resources Code section 3234.

(b) Written notification of a well stimulation treatment shall include certification of all of the following:

(1) Attached to the notice is a complete list of the names, Chemical Abstract Service (CAS) numbers, and estimated concentrations, in percent by mass, of each and every chemical constituent of the well stimulation fluids anticipated to be used in the treatment, as required by Public Resources Code section 3160, subdivision (d)(1)(D). If a CAS number does not exist for a chemical constituent, another unique identifier has been provided, if available.

(2) Attached to the notice is a Water Management Plan that includes all of the information required by Public Resources Code section 3160, subdivision (d)(1)(C).

(3) Attached to the notice is a list of locations of existing wells, including plugged and abandoned wells, that may be impacted by the fractures or modifications, as required by Public Resources Code section 3160, subdivision (d)(1)(E).

(4) Attached to the notice is a Groundwater Monitoring Plan that meets the requirements of Section 1783.4.

(5) The operator has contracted with an independent entity to provide neighboring property owners and tenants with a copy of this notice and the attachments thereto, and with information about the avail- ability of water testing, as required by Public Resources Code section 3160, subdivision (d)(6). The well stimulation will not commence until 30 days after the required notice has been provided. If a notified property owner makes a timely, written request for water sampling and testing, then the operator will pay for testing and sampling by one or more qualified independent third-party contractors designated by the State Water Resources Control Board, provided that the sampling and testing is consistent with the standards and protocols specified by the State Water Resources Control Board pursuant to Public Resources Code section 3160(d)(7)(B) and is conducted in accordance with Public Resources Code section 3160, subdivision (d) (7)(A). If a notified property owner makes a timely, written request for water sampling and testing, then the well stimulation will not commence until requested baseline water sampling and testing is complete.

(6) Within 60 days after the cessation of the well stimulation treatment, the above-named opera- tor will make all public disclosures required by Public Resources Code section 3160, subdivisions (b) and (g), and pursuant to Section 1788.

(c) A claim of trade secret protection for the information required under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j). Notwithstanding any claim of trade secret protection, the Division shall not approve as complete an Interim Well Stimulation Treatment Notice unless all of the information specified in Public Resources Code section 3160, subdivision (d)(1)(D), has been provided to the Division.

§ 1783.1. Contents of Application for Permit to Perform Well Stimulation Treatment [Effective July 1, 2015]

(a) An application for a permit to perform a well stimulation treatment shall include the following:

(1) Operator's name;

(2) Name and telephone number of person filing the form;

(3) Name of person to contact with technical questions regarding operations;

(4) Telephone number and email address of person to contact with technical questions regarding operations;

(5) Lease name and number of the well;

(6) Location of the well, submitted as a six-digit decimal degrees, non-projected, Latitude and Longitude, in the Geographic Coordinate System (GCS) NAD83.

(7) API number assigned to the well by the Division;

(8) Type of well;

(9) Name of the oil field;

(10) County in which the well is located;

(11) The estimated two-week time period during which the well stimulation treatment is planned to occur;

(12) Estimated measured and estimated true vertical depth of the well, and a description of the wellbore path that is specific enough to identify the location of the well stimulation treatment;

(13) Formation name and vertical depth of the top and bottom of the productive horizon where well stimulation treatment will occur;

(14) The maximum number of stages in the well stimulation treatment;

(15) For each stage of the well stimulation treatment, the estimated measured and estimated true vertical depth of the planned interval of the well stimulation treatment on the well bore;

(16) The ADSA for each stage;

(17) For each stage of the well stimulation treatment, the anticipated volume, rate, and pressures of fluid to be injected;

(18) Identification of all wells that have previously been subject to well stimulation treatment in the same production horizon within the area of twice the ADSA;

(19) Identification of where in the operator's Spill Contingency Plan handling of well stimulation fluid and additives has been addressed;

(20) The operator's plan for completing the cement evaluation required under Section 1784.2(a), or a request for approval of an alternate cement evaluation plan under Section 1784.2(c);

(21) The information required for the well stimulation treatment area analysis under Section 1784(a);

(22) The well stimulation treatment design required under Section 1784(b);

(23) A water management plan that includes all of the following:

(A) An estimate of the amount of water to be used in the treatment;

(B) An estimate of water to be recycled following the well stimulation treatment;

(C) A description of how and where the water from a well stimulation treatment will be recycled, including a description of any treatment or reclamation activities to be conducted prior to recycling or reuse;

(D) The anticipated source of the water to be used in the treatment, including any of the

(i) The well or wells, if commingled, from which the water will be produced or extracted;

(ii) The water supplier, if it will be purchased from a supplier;

(iii) The point of diversion of surface water; and

(E) The anticipated disposal method that will be used for the recovered water in the flowback fluid from the treatment that is not produced water that would be reported pursuant to Section 3227;

(24) A description of anticipated procedures to comply with the Hazardous Waste Control Law (Health and Safety Code §§ 25100 et seq.) and implementing regulations pertaining to the activities and information provided under this article;

(25) The anticipated source, amount, and composition of the base fluids to be used in the treatment, including pH, flash point, and any constituents listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A) and (B);

(26) The estimated amount of treatment-generated waste materials that are not addressed by the water management plan, and the anticipated disposal method for the waste materials;

(27) Documentation from either the State Water Board or the Regional Water Board that the well subject to the well stimulation treatment is covered by a regional groundwater monitoring program pursuant to Water Code section 10783, subdivision (h)(1), or indication that the

operator is working with the State Water Board or the Regional Water Board to ensure that the well subject to well stimulation treatment is covered in accordance with Water Code section 10783;

(28) A complete list of the names, Chemical Abstract Service numbers, and estimated concentrations, in percent by mass, of each and every chemical constituent of the well stimulation fluids anticipated

to be used in the treatment (if a Chemical Abstract Service number does not exist for a chemical constituent, another unique identifier may be used, if available);

(29) Whether it is anticipated that radiological components or tracers will be injected during the well stimulation treatment;

(30) The State Clearinghouse Number or other identification of all documents prepared under the California Environmental Quality Act that relate to the proposed well stimulation treatment; and

(31) Other information as requested by the Division.

(b) A claim of trade secret protection for the information required under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j).

(c) Notwithstanding any claim of trade secret protection, the Division shall not approve as complete an application for a permit to perform a well stimulation treatment unless all of the information specified in this paragraph has been provided to the Division.

§ 1783.2. Copy of Interim Well Stimulation Treatment Notice; Notice of Availability for Water Testing, Sampling; Request for Water Testing [Effective until July 1, 2015]

(a) At least 30 days in advance of commencing well stimulation treatment, the operator of the well subject to well stimulation treatment is required to provide to surface property owners and tenants of legally recognized parcels of land situated within a 1500-foot radius of the wellhead of any such well, or within

500 feet of the horizontal projection of the subsurface parts of any such well, the following:

(1) A copy of the Interim Well Stimulation Treatment Notice, approved as complete by the Division;

(2) Notice of the availability of water sampling and testing of any water well located on the parcel that is suitable for drinking or irrigation purposes;

(3) Notice of the availability of water sampling and testing of any surface water located on the parcel that is suitable for drinking or irrigation purposes; and

(4) Information about how to request water sampling and testing, and notice that a request for water sampling and testing must be made within 20 days of receipt of the notification.

(b) A property owner notified pursuant to this section may request water quality sampling and testing on any water well located on the parcel that is suitable for drinking or irrigation purposes and on any sur- face water located on the parcel that is suitable for drinking or irrigation purposes, provided that the request is made in writing within 20 days of receipt of the notification. Upon receipt of a timely, written request for water quality sampling and testing, the operator shall pay for testing and sampling by one or more qualified independent third-party contractors designated by the State Water Resources Control Board, provided that the sampling and testing is consistent with the standards and protocols specified by the State Water Resources Control Board pursuant to Public Resources Code section 3160(d)(7)(B) and is conducted in accordance with Public Resources Code section 3160, subdivision (d)(7)(A).

(c) For the purposes of this section, “tenant” means a person or entity possessing the right to occupy a legally recognized parcel, or portion thereof.

(d) For the purposes of this section, “horizontal projection” means the surface representation of the horizontal path of the wellbore.

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§ 1783.2. Neighbor Notification, Duty to Hire Independent Third Party [Effective July 1, 2015]

(a) The operator of any oil or gas well receiving a permit to conduct well stimulation treatment from the Division shall hire an independent third party to perform the following actions:

(1) Identify surface property owners and tenants, other than the operator of the well subject to well stimulation treatment, of legally recognized parcels of land situated within a 1500-foot radius of the wellhead receiving well stimulation treatment, or within 500 feet of the surface representation of the horizontal path of the subsurface parts of such well;

(2) Provide all surface property owners and tenants so identified, or their duly authorized agents, with neighbor notification that shall include and must be limited to both of the following:

(A) A copy of the approved well stimulation treatment permit; and

(B) A completed Well Stimulation Treatment Neighbor Notification Form (7/15 version), hereby incorporated by reference; and

(3) Compile and mail to the Division a declaration of notice pursuant to subdivision (i).

(b) Neighbor notification is not required if the independent third party determines that there are no surface property owners or tenants as described in subdivision (a)(1).

(c) A well stimulation treatment subject to the neighbor notification requirements of this section shall not commence until 30 calendar days after all required notices are provided, as defined in subdivision (e).

If the independent third party has made a determination under subdivision (b) that neighbor notification is not required, then the well stimulation treatment shall not commence until at least 72 hours after the opera- tor provides the Division with a signed written statement from the independent third party certifying that determination.

(d) The notice required under subdivision (a)(2) may be given by any of the following means:

(1) Personal delivery;

(2) Overnight delivery by an express service carrier;

(3) Registered, certified, or express mail;

(4) Electronic mail or facsimile, but only if the person to be notified has agreed in writing prior to the notice to accept notice by electronic mail or facsimile. The prior written agreement shall contain the email address or facsimile number of the person to be notified, which address or number shall be used until otherwise instructed by the person to be notified.

(e) The notice required under this section is deemed to have been provided at the following times:

(1) If given by personal delivery, when delivered;

(2) If given by overnight delivery by an express service carrier, 2 calendar days after the notice is deposited with the carrier;

(3) If given by registered, certified or express mail, 5 calendar days after the notice is deposited in the mail;

(4) If given by electronic mail or facsimile, 2 calendar days after the notice is transmitted.

(f) Any notice that is given to surface property owners by overnight delivery by an express service carrier or by registered, certified, or express mail shall be addressed to the address of record for that person, or his/her duly authorized agent, as shown on the latest equalized assessment roll, county assessor or tax collector records. In addition, if the owner's address of record is different from the physical address of the property within the notification radius, and if that property is capable of receiving mail, a copy of the notice shall also be delivered or mailed to that property.

(g) Notice to a tenant shall not be considered deficient for lack of a named individual. Notice to any tenant can be addressed generally to “current resident,” “current occupant,” or such other non-specific addressee, as may be appropriate.

(h) In addition to the means set forth in subdivision (d), tenants of a residential or commercial property that has 10 or more individual units for lease may be provided notice by leaving the copy of the permit and Well Stimulation Treatment Neighbor Notification Form at each individual residential or commercial unit within the residential or commercial property between the hours of eight in the morning and six in the evening, with some person not less than 18 years of age who provides a signature acknowledging receipt of the notice. Notice given in accordance with this subdivision shall be treated as a personal delivery for purposes of determining when such notice is deemed provided under subdivision (e).

(i) The independent third party hired by the operator to provide notice under this section shall, within 5 calendar days of all required notices having been provided for a well stimulation treatment, submit to the Division in a text-searchable electronic format, directed to the email address "NeighborNotificationWST@ conservation.ca.gov" a declaration of notice that provides all of the following:

(1) Identifying information for the well receiving well stimulation treatment and the operator of that well;

(2) A list of all notices provided, itemized by the County Assessor's Parcel Number for the property within the notification radius that corresponds to each notice provided;

(3) The name of each surface property owner and tenant notified, or indication that the addressee was unspecified, as allowed under subdivision (g);

(4) The specific method of providing each notice, including the physical or electronic address to which each notice was sent;

(5) The date each notice was personally delivered, deposited with an express carrier or mail service, or transmitted electronically;

(6) The date each notice is deemed to have been provided in accordance with subdivision (e); and

(7) Representative copies of the completed Well Stimulation Treatment Neighbor Notification Form that were provided.

(j) If any additional surface property owners or tenants are notified after the original declaration of notice is provided to the Division, then the independent third party shall within 5 calendar days submit to the Division a supplemental declaration of notice that contains the information listed in subdivision (i).

(k) Each independent third party hired by the operator to provide notice under this section shall retain copies of all of the following:

(1) A representative copy of the well stimulation treatment permits provided to surface property owners and tenants;

(2) Representative copies of the completed Well Stimulation Treatment Neighbor Notification Form provided to surface property owners and tenants;

(3) Documentation demonstrating that the notices required under this section were provided, including documentation from the United States Postal Service or express service carrier such as proof of payment records, return receipts, delivery confirmations, and tracking records; and

(4) Records relied upon to identify surface property owners and tenants who must receive notice under this section.

(l) Records specified for retention under subdivision (k) shall be made available to the Division promptly upon request, and shall be maintained for at least 5 years from the date that the declaration of notice required under subdivision (h) is submitted to the Division.

§ 1783.3. Duty to Hire Independent Third Party to Provide Copy of Permit, Notice of Water Testing, Sampling [Effective until July 1, 2015]

(a) It is the operator's responsibility to identify the surface property owners and tenants to whom a copy of the completed Interim Well Stimulation Treatment Notice must be provided and notification is required under Section 1783.2. To fulfill this responsibility, the operator or owner must hire an independent person or entity to provide a copy of the Interim Well Stimulation Treatment Notice and the notification required.

(b) Any person or entity hired by the owner of a well to provide a copy of the Interim Well Stimulation Treatment Notice and notice in accordance with this regulation shall, after providing such notice, deliver to the Division, in writing, the following:

(1) The names of the property owners or tenants identified;

(2) The method by which the copy of the completed Interim Well Stimulation Treatment Notice was provided, and the date on which the copy of the completed Interim Well Stimulation Treatment Notice was provided; and

(3) The method by which the notice of the availability of water sampling and testing was provided, and the date on which the notice was provided.

(c) Information about the availability of water quality testing may be included in the notification or the notification may reference a website with further information about testing options.

§ 1783.3. Availability of Water Testing, Request for Water Testing [Effective July 1, 2015]

(a) A surface property owner notified pursuant to Section 1783.2 may request water quality testing on any existing water well or surface water located on the parcel that is suitable for drinking or irrigation purposes.

(b) When a surface property owner makes a request for water quality testing on any water well or surface water pursuant to subdivision (a), sampling and testing shall be in accordance with the following:

(1) Water quality testing shall be performed by a Designated Contractor for Water Sampling.

(2) Water quality testing shall be conducted in accordance with the standards and protocols specified by the State Water Board pursuant to Public Resources Code section 3160, subdivision (d)(7)(B).

(3) Water quality testing shall include baseline measurements prior to the commencement of the well stimulation treatment, and follow-up measurements after the well stimulation treatment is completed.

(4) Any written request for water testing shall specify whether the surface property owner elects to select the Designated Contractor for Water Sampling and communicate directly with the contractor to arrange for testing, or, alternatively, elects to have the operator select the Designated Contractor for Water Sampling and arrange for testing.

(A) If the surface property owner elects to have the operator select and contract with the Designated Contractor for Water Sampling, the well stimulation treatment may not commence until the re- quested baseline water sampling is completed, provided that the request is made in writing and postmarked to the operator within 20 calendar days from the date notice is provided under section 1783.2(e) and the surface property owner makes necessary accommodations to enable the collection of baseline measurements without undue delay.

(B) If the surface property owner elects to select the Designated Contractor for Water Sampling and communicate directly with the contractor to arrange for testing, the surface property owner is responsible for scheduling baseline measurements to be taken prior to the commencement of the well stimulation treatment. The operator shall immediately inform the surface property owner when the well stimulation treatment is completed so that follow-up measurements can be collected.

(5) The operator shall pay for all reasonable costs of water quality testing under this subdivision regardless of whether the surface property owner or the operator selects and coordinates with the Designated Contractor for Water Sampling.

(6) The results of any water quality testing shall be provided to the Division, the appropriate Regional Water Board, the State Water Board, the surface property owner, and any tenant notified pursuant to Section 1783.2 to the extent authorized by the tenant's lease.

(7) The Regional Water Board shall be notified at least two working days prior to collecting a sample under this section so that Regional Water Board staff may witness the sampling.

(c) Water quality data collected under subdivision (b) shall be submitted to the Regional Water

Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.

(d) A tenant notified pursuant to Section 1783.2 that has lawful use of any existing water well or surface water located on the parcel that is suitable for drinking or irrigation purposes may independently contract with a Designated Contractor for Water Sampling for water quality testing of such water. A tenant that contracts for such testing is responsible for scheduling baseline measurements to be taken prior to the commencement of the well stimulation treatment. A tenant that contracts for water testing pursuant to this section is not entitled to reimbursement from the operator for the costs of such testing. If the operator is made aware of the tenant's contracting for water quality testing, then the operator shall immediately notify the tenant when the well stimulation treatment is completed so that follow-up measurements can be collected.

§ 1783.4. Groundwater Sampling, Testing, and Monitoring

(a) The purpose of this section is to provide interim model groundwater monitoring criteria for groundwater sampling, testing, and monitoring related to well stimulation that is conducted prior to the finalization of model groundwater monitoring criteria by the State Water Resources Control Board. These interim criteria do not apply to regional groundwater monitoring programs developed by the State Water Resources Control Board or the Regional Water Board.

(b) A well-specific (also referred to as “well-by-well”) or area-specific (also referred to as “oil or gas field-specific”) groundwater monitoring plan shall include all of the following:

(1) A map and cross section of the well borehole(s) to undergo well stimulation treatment, showing the well name(s), extent and orientation of the planned fracture network, the stratigraphic depths of protected waters, and the stratigraphic depths of low-permeability zones that will function to slow the migration of fluids towards protected waters or the surface.

(2) Complete well construction details for the well borehole(s) to undergo well stimulation treatment and all new and existing groundwater wells that will be used for monitoring.

(3) To the extent that information is publicly available, a map showing the location of all existing groundwater supply wells (public, private domestic, irrigation, and industrial) and groundwater monitoring wells within a 1500-foot radius of the well(s) to undergo well stimulation treatment, or within 500 feet of the surface representation of the horizontal path of the wellbore of any such well.

(4) A map showing location of any abandoned or inactive wells within a 1500-foot radius of the well(s) to undergo well stimulation treatment, or within 500 feet of the surface representation of the horizontal path of the wellbore of any such well.

(5) A map showing location of groundwater wells (new and existing monitoring wells and supply wells) to be sampled in the groundwater monitoring plan.

(6) A contingency plan for reporting information in the event of a well failure, or any other unintended event that has the potential to affect groundwater quality, such as the detection of a fracture beyond the intended zone or into protected waters. A "well failure" means instances where the well casing has been compromised producing a subsurface leak into water bearing zones and is a potential threat to groundwater quality. The contingency plan shall, at a minimum, require the well operator to submit the following information to the Division, the State Water Resources Control Board, and the appropriate Regional Water Board within 48 hours of discovery of a well failure or other unintended event that has the potential to affect groundwater quality:

(A) A description of the activities leading up to the well failure or unintended event;

(B) Depth interval(s) of the well failure or unintended event;

(C) Chemical composition of the well stimulation treatment fluid and of the fluid in the well at the time of the well failure, or unintended event; and

(D) An estimate of the volume of fluid lost during well failure, or unintended event.

(c) Well-specific and area-specific groundwater monitoring should be designed to assess whether protected waters have been impacted by well stimulation treatment. Groundwater wells to be used for groundwater monitoring should be located within reasonable proximity of the oil or gas well(s) undergoing stimulation treatment. Groundwater wells to be used for groundwater monitoring should be screened at depths in the aquifer where existing groundwater supply wells are screened. Additional groundwater wells to be used for groundwater monitoring should be screened near the base of protected waters. The number of new and existing groundwater wells to be used for groundwater monitoring, their locations, depths, screened intervals, and justification for their use shall be included in the groundwater monitoring plan. If any groundwater wells identified in accordance with subsection (b)(3) are not to be used for groundwater monitoring, a justification for their exclusion shall be included in the groundwater monitoring plan. The Division shall not approve as complete an Interim Well Stimulation Treatment Notice submitted on or after January 1, 2014 that asserts the absence of protected water as the basis for not conducting groundwater monitoring unless the submittal includes written concurrence by the Water Boards with the operator's determination of the absence of protected water.

(d) If new groundwater wells are used for well-specific or area-specific groundwater monitoring, they shall be constructed in accordance with any applicable local well ordinances. If there are no applicable local well ordinances, they shall be constructed in accordance with the California Well Standards contained in Department of Water Resources Bulletin 74-81 (publicly available at http://www.water.ca.gov// pubs/groundwater/water_well_standards_bulletin_74-81_/ca_well_standards_bulletin74-81_1981.pdf), as supplemented by Department of Water Resources Bulletin 74-90 (publicly available at http://www.water.ca.gov/pubs/groundwater/water_well_standards_bulletin_74-90_/ca_well_standards_bulletin74-90_1991. pdf).

(e) For well-specific and area-specific groundwater monitoring, the operator should sample the groundwater monitoring wells frequently enough to detect changes in water quality. The operator shall sample the groundwater monitoring wells before well stimulation commences to establish a groundwater quality baseline and at least once within 60 days after the well stimulation is completed. The well operator shall sample the wells semiannually thereafter until the State Water Resources Control Board has developed its final groundwater monitoring model criteria.

(f) For all groundwater sampling, testing, and monitoring conducted pursuant to this Article, ground-water shall be measured for field parameters including pH, temperature, and electrical conductivity. For all groundwater sampling, testing, and monitoring conducted pursuant to this Article, groundwater samples shall be analyzed using current applicable EPA-approved analytical methods for water, if available, for all of the following: appropriate indicator compounds(s) for the well stimulation treatment fluid; total dis- solved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2) (A); benzene, toluene, ethylbenzene, and xylenes; total petroleum hydrocarbons for crude oil; polynuclear aromatic hydrocarbons (including acenaphthene, acenaphthylene, anthracene, benzo[a]anthracene, benzo[b]fluoranthene, benzo[k]fluoranthene, benzo[a]pyrene, benzo[g,h,i]perylene, chrysene, dibenzo[a,h]anthracene, fluoranthene, fluorene, indeno[1,2,3-cd]pyrene, naphthalene, phenanthrene, and pyrene); radionuclides listed under California Code of Regulations, title 22, Table 64442; methane; major and minor cations (including sodium, potassium, magnesium, and calcium); major and minor anions (including nitrate, chloride, sulfate, alkalinity, and bromide); and trace elements (including lithium, strontium, and boron).

(g) For all groundwater sampling, testing, and monitoring conducted pursuant to this Article, groundwater sampling shall be done in accordance with all of the following:

(1) All groundwater sampling is to be performed by a qualified person. A qualified person is any person with the knowledge and training in proper sampling methods, chain of custody, and

quality assurance/quality control protocols. Any person conducting groundwater sampling, other than personnel from an approved laboratory, shall consult with the laboratory to ensure that the sampler understands and follows the proper sampling collection procedures and protocols.

(2) Procedures to sample groundwater monitoring wells shall be consistent with U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002)(publicly available at www.epa.gov/superfund/remedytech/tsp/download/ gw_sampling_guide.pdf). All procedures to sample groundwater supply wells shall be consistent with US EPA Science and Ecosystem Support Division Operating Procedure for Groundwater Sampling (March 2013) (publicly available at www.epa.gov/region04/sesd/fbqstp/Groundwater-Sampling.pdf).

(3) All analytical testing shall be performed by a laboratory that is certified by the California Department of Public Health environmental laboratory accreditation program (ELAP).

(4) All groundwater monitoring data collected in accordance with a well-by-well or area-specific groundwater monitoring plan shall be compiled in groundwater monitoring reports, and submitted to the State Water Resources Control Board. Data collected prior to commencement of, and within 60 days of completion of, well stimulation treatment shall be submitted in a single groundwater monitoring report. Subsequent semiannual data should be submitted in semiannual groundwater monitoring reports. Ground- water monitoring reports shall include at a minimum:

(A) Site plan with locations of wells used for groundwater monitoring, and oil and gas wells.

(B) Table(s) of analytical results, with both recent and historical data in chronological order and tabulated by well number.

(C) Maps and/or cross-sections displaying groundwater analytical results.

(D) Well completion reports and associated lithologic information for sampled well(s).

(E) Description of field procedures, including well installation or selection, and groundwater sampling.

(F) Copies of analytical laboratory reports, including quality assurance/quality control procedures and analytical test methods.

(G) Changes, if any, to the scope of work, and rationale for the changes.

(H) Decontamination procedures.

(I) Waste management and disposal procedures, including associated documentation.

(5) All groundwater quality data and groundwater monitoring reports shall be submitted to the State Water Resources Control Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, division 3, chapter 30 (commencing with section 3890).

§ 1784. Well Stimulation Treatment Area Analysis and Design

(a) As part of an application for a permit to conduct well stimulation, the operator shall conduct a well stimulation treatment area analysis to ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatment.

(1) The operator shall utilize modelling, or other analysis, approved by the Division that will effectively estimate the ADSA. The operator shall submit the ADSA and information supporting the modeling or analysis to the Division.

(2) The well stimulation treatment area analysis shall include identification and review of all well bores located completely or partially within two times the ADSA to ensure the geologic and hydro- logic isolation of the oil and gas formation during and following well stimulation. The Division may allow modification of the review area based on modeling and analysis provided by the operator that demonstrates geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatment. For each well bore within the review area the well stimulation treatment area analysis shall include the following information:

(A) Casing diagrams clearly indicating:

(i) Sizes and weights of casing;

(ii) Depths of shoes, stubs, and liner tops;

(iii) Depths of perforation intervals, water shutoff holes, cement port, cavity shots, cuts, casing damage, and top of junk or fish left in well;

(iv) Diameter and depth of hole;

(v) Cement plugs inside casings, including top and bottom of cement plug, with indication of method of determining;

(vi) Cement fill behind casings, including top and bottom of cement fill, with indication of method of determining;

(vii) Type and weight (density) of fluid between cement plugs;

(viii) Depths and names of the formations, zones, and sand markers penetrated by the well, including the top and bottom of the zone where well stimulation treatment will occur;

(ix) All steps of cement yield and cement calculations performed;

(x) All information used to calculate the cement slurry (volume, density, yield), including but not limited to, cement type and additives, for each cement job completed in each well; and

(xi) All of the information listed in this paragraph for all previous redrilled or sidetracked well bores.

(B) For directionally drilled wells, a wellbore path giving both inclination and azimuth measurements.

(3) The well stimulation treatment area analysis shall include a review of all geologic features, including known faults (active or inactive), within five times the ADSA to ensure the geologic and hydro- logic isolation of the oil and gas formation during and following well stimulation. For all such geologic features, the operator shall provide:

(A) An evaluation of whether the geologic feature may act as a migration pathway for injected fluids or displaced formation fluids; and

(B) An assessment of the risk that the well stimulation treatment will communicate with the geologic feature.

(4) If five times the ADSA extends beyond the productive horizon being evaluated for possible well stimulation treatment, then the well stimulation treatment area analysis shall include a review of the geological formations adjacent to the productive horizon. The operator shall assess the mechanical rock properties, including permeability, relative hardness (using Young's Modulus), relative elasticity (using Poisson's Ratio), and other relevant characteristics of the

geological formations to determine whether the geological formations will ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation.

(5) The well stimulation treatment area analysis shall include identification of all water within two times the ADSA.

(b) Utilizing the well stimulation treatment area analysis conducted pursuant to subdivision (a), the operator shall design the well stimulation treatment so as to ensure that the well stimulation treatment fluids or hydrocarbons do not migrate and remain geologically and hydrologically isolated to the hydrocarbon formation. A well stimulation treatment shall not be designed to employ pressure exceeding 80% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment. Authority: Sections 3013 and 3160, Public Resources Code. Reference: Sections 3106 and 3160, Public Resources Code.

§ 1784.1. Pressure Testing Prior to Well Stimulation Treatment

(a) The operator shall conduct pressure testing not more than 30 days before commencing well stimulation treatment, but after all operations that could affect well integrity or the integrity of the equipment are complete. Pressure testing shall include the following:

(1) All cemented casing strings and all tubing strings to be utilized in the well stimulation treatment operations shall be pressure tested for at least 30 minutes at a pressure equal to at least 100% of the maximum surface pressure anticipated during the well stimulation treatment, but not greater than the API rated minimum internal yield of the tested casing. The operator shall chart the pressure testing. If during testing, and after equilibrium has been reached, there is a pressure change of 10% or more from the original test pressure, then the operator shall immediately notify the Division, the operator shall provide the Division with copies of the charting of the pressure testing, and the tested casing or tubing shall not be used until the cause of the pressure drop is identified and corrected to the Division's satisfaction. No casing or tubing shall be used unless it has been successfully tested pursuant to this section.

(2) All surface equipment to be utilized for well stimulation treatment shall be rigged up as designed. The pump, and all equipment downstream from the pump, shall be pressure tested at a pressure equal to 125% of the maximum surface pressure anticipated during the well stimulation treatment, but not greater than the manufacturer's pressure rating for the equipment being tested. If during testing there is a pressure change of 10% or more from the original test pressure, then the operator shall immediately notify the Division, and the tested equipment shall not be used until the cause of the pressure change is identified and corrected to the Division's satisfaction. No equipment shall be used unless it has been successfully tested pursuant to this section.

(b) The operator shall notify the Division at least 24 hours prior to conducting the pressure testing required under subdivision (a) so that Division staff may witness. The charting of pressure testing required under subdivision (a)(1) shall be provided to the Division not less than 12 hours before commencing well stimulation treatment.

§ 1784.2. Cement Evaluation Prior to Well Stimulation Treatment

(a) In advance of conducting well stimulation treatment, but at least 48 hours after cement placement, the operator shall run a radial cement evaluation log or other cement evaluation method that is approved by the Division, and the cement evaluation shall demonstrate the following:

(1) The well was and continues to be cemented in accordance with the requirements of Section

1722.4 if it is an onshore well, or Section 1744.3 if it is an offshore well; and

(2) The quality of the cement is sufficient to ensure the geologic and hydrologic isolation of the oil and gas formation during and following well stimulation treatment.

(b) Documentation of the cement evaluation shall be provided to the Division not less than 72 hours before commencement of the well stimulation treatment. If the Division identifies a concern with the cement evaluation, the well stimulation treatment shall not commence until the concern has been addressed to the Division's satisfaction.

(c) The Division may approve an alternate cement evaluation plan that waives the requirements

of subdivisions (a) and (b) if the Division is satisfied that, based on geologic and engineering information available from previous drilling or producing operations in the area where the well stimulation treatment will occur, well construction and cementing methods have been established that ensure that there will be no voids in the annular space of the well. A request for approval of an alternate cement evaluation plan shall be submitted to the Division as part of the application for a permit to perform well stimulation treatment submitted under Section 1783.

§ 1785. Monitoring During Well Stimulation Treatment Operations

(a) The operator shall continuously monitor and record all of the following parameters during the well stimulation treatment, if applicable:

(1) Surface injection pressure;

(2) Slurry rate;

(3) Proppant concentration;

(4) Fluid rate; and

(5) All annuli pressures.

(b) The operator shall terminate the well stimulation treatment and immediately provide the collected data to the Division if any of the following occurs:

(1) A pressure change in the annulus between the tubing or casing through which well stimulation treatment fluid is conducted and the next larger tubular or casing more than 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion;

(2) Pressure exceeding 90% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment, if the pressure testing under Section

1784.1(a)(1) was done at a pressure equal to 100% of the API rated minimum internal yield of the tested casing;

(3) Pressure exceeding 80% of the API rated minimum internal yield on any casing string in communication with the well stimulation treatment, if the pressure testing under Section 1784.1(a)(1) was done at a pressure equal to less than 100% of the API rated minimum internal yield of the tested casing; or

(4) The operator has reason to suspect a potential breach in the cemented casing strings, the tubing strings utilized in the well stimulation treatment operations, or the geologic or hydrologic isolation of the formation.

(c) If any of the events listed in subdivision (b) occurs, then the operator shall perform diagnostic testing on the well to determine whether a breach has occurred. Diagnostic testing shall be done as soon as is reasonably practical. The Division shall be notified when diagnostic testing is being done so that Division staff may witness the testing. All diagnostic testing results shall be immediately provided to the Division.

(d) If diagnostic testing reveals that a breach has occurred, then the operator shall immediately shut- in the well, isolate the perforated interval, and notify the Division and the Regional Water Board with all of the following information:

(1) A description of the activities leading up to the well breach.

(2) Depth interval of the well breach and methods used to determine the depth interval.

(3) An exact description of the chemical constituents of the well stimulation treatment fluid, or of the fluid that is most representative of the fluid composition in the well at the time of the well breach.

(e) The operator shall not resume operation of a well that has been shut-in under subdivision (d) without first obtaining approval from the Division.

(f) Groundwater quality data submitted under subdivision (d) shall be in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.

(g) If the surface casing annulus is not open to atmospheric pressure, then the surface casing pressures shall be monitored with a gauge and pressure relief device. The maximum set pressure on the relief device shall be the lowest of the following and well stimulation treatment shall be terminated if pressures in excess of the maximum set pressure are observed in the surface casing annulus:

(1) A pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet);

(2) 70% of the API rated minimum internal yield for the surface casing; or

(3) A pressure change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion.

§ 1785.1. Monitoring and Evaluation of Seismic Activity in the Vicinity of Hydraulic Fracturing

(a) From commencement of hydraulic fracturing until 10 days after the end of hydraulic fracturing, the operator shall monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of five times the ADSA.

(b) If an earthquake of magnitude 2.7 or greater is identified under subdivision (a), then the follow- ing requirements shall apply:

(1) The operator shall immediately notify the Division and inform the Division when the earth-quake occurred relative to the hydraulic fracturing operations.

(2) The Division, in consultation with the operator and the California Geological Survey, will conduct an evaluation of the following:

(A) Whether there is indication of a causal connection between the hydraulic fracturing and the earthquake;

(B) Whether there is a pattern of seismic activity in the area that correlates with nearby hydraulic fracturing; and

(C) Whether the mechanical integrity of any active well within the radius specified in sub- division (a) has been compromised.

(3) No further hydraulic fracturing shall be done within the radius specified in subdivision (a) until the Division has completed the evaluation under subdivision (b)(2) and is satisfied that hydraulic fracturing within that radius does not create a heightened risk of seismic activity.

§ 1786. Storage and Handling of Well Stimulation Treatment Fluids and Wastes

(a) Operators shall adhere to the following requirements for the storage and handling of well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment:

(1) Fluids shall be stored in compliance with the secondary containment requirements of Section 1773.1, except that secondary containment is not required under this section for production facilities that are in one location for less than 30 days. The operator's Spill Contingency Plan shall account for all production facilities outside of secondary containment and include specific steps to be taken and equipment available to address a spill outside of secondary containment.

(2) Operators shall be in compliance with all applicable testing, inspection, and maintenance requirements for production facilities containing well stimulation treatment fluids.

(3) Fluids shall be accounted for in the operator's Spill Contingency Plan.

(4) Fluids shall be stored in containers and shall not be stored in sumps or pits.

(5) In the event of an unauthorized release, the operator shall immediately implement the Spill Contingency Plan; notify the Regional Water Board and any other appropriate response entities for the location and the type of fluids involved, as required by all applicable federal, state, and local laws and regulations; and shall perform clean up and remediation of the area, and dispose of any cleanup or remediation waste, as required by all applicable federal, state, and local laws and regulations.

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(6) Within 5 days of the occurrence of an unauthorized release, the operator shall provide the Division a written report that includes:

(A) A description of the activities leading up to the release;

(B) The type and volumes of fluid released;

(C) The cause(s) of release;

(D) Action taken to stop, control, and respond to the release; and

(E) Steps taken and any changes in operational procedures implemented by the operator to prevent future releases.

(7) Operators shall conduct all activities that relate to storage and management of fluids in compliance with all applicable requirements of the Regional Water Board, the Department of Toxic Substances Control, the Air Resources Board, the Air Quality Management District or Air Pollution Control District, the Certified Unified Program Agency, and any other state or local agencies with jurisdiction over the location of the well stimulation activities.

(8) An operator who generates a waste, as defined in Health and Safety Code section 25124 and California Code of Regulations, title 22, section 66261.2, in the course of conducting well stimulation activities, including but not limited to well stimulation treatment fluid, additives, produced water from a well, solids separated from well stimulation treatment fluid, remediation wastes, or any other wastes generated from the processing, treatment or management of these wastes, shall determine if the waste is a hazardous waste by sampling and testing the waste according to the methods set forth in California Code of Regulations, title 22, division 4.5, chapter 11, article 3 (section 66261.20 et seq.), or according to an equivalent method approved by the Department of Toxic Substances Control pursuant to California Code of Regulations, title 22, section 66260.21, except where the operator has determined that the waste is excluded from regulation under California Code of Regulations, title 22, section 66261.4 or Health and Safety Code section 25143.2. Notwithstanding any other section in this article, wastes that are

determined by the operator to be hazardous wastes shall be managed in compliance with all hazardous waste management requirements of the Department of Toxic Substances Control.

§ 1787. Well Monitoring After Well Stimulation Treatment

(a) Operators shall monitor each well that has had a well stimulation treatment as specified in sub-division (d) to identify any indication of a well breach. If monitoring indicates that a well breach may have occurred, then the operator shall perform diagnostic testing on the well to determine whether a breach has occurred. Diagnostic testing shall be done as soon as is reasonably practical. The Division shall be notified when diagnostic testing is being done so that Division staff may witness the testing. All diagnostic testing results shall be immediately provided to the Division.

(b) If diagnostic testing reveals that a breach has occurred, then the operator shall immediately shut- in the well, isolate the perforated interval, and notify the Division and the Regional Water Board with all of the following information:

(1) A description of the activities leading up to the well breach.

(2) Depth interval of the well breach and methods used to determine the depth interval.

(3) An exact description of the chemical constituents of the fluid that is most representative of the fluid composition in the well at the time of the well breach.

(c) The operator shall not resume operation of a well that has been shut-in under subdivision (b) without first obtaining approval from the Division.

(d) Operators shall adhere to the following requirements for a well that has had a well stimulation treatment:

(1) The production pressure of the well shall be monitored at least once every two days for the first thirty days after the well stimulation treatment and on a monthly basis thereafter. Information regarding production pressures shall be reported to the Division on a monthly basis.

(2) The annular pressures of the well shall be reported to the Division annually, unless it has been demonstrated to the Division's satisfaction that there are no voids in the annular space. It shall be immediately reported to the Division if annular pressure exceeds 70% of the API rated minimum internal yield or collapse strength of casing, or if surface casing pressures exceed a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet).

(3) The annular valve shall be kept accessible from the surface or left open and plumbed to the surface with a working pressure gauge unless it has been demonstrated to the Division's satisfaction that there are no voids in the annular space.

(4) A properly functioning pressure relief device shall be installed on the annulus between the surface casing and the production casing, or, if intermediate casing is set, on the annuli between the sur- face casing and the intermediate casing and the production casing. This requirement may be waived by the Division, if the operator demonstrates to the Division's satisfaction that the installation of a pressure relief device is unnecessary based on technical analysis and/or operating experience in the area.

(5) If a pressure relief device is installed, then all pressure releases from the device shall be immediately reported to the Division. The maximum set pressure of a surface casing pressure relief device shall be the lowest of the following:

(A) A pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet);

(B) 70% of the API rated minimum internal yield for the surface casing; or

(C) A pressure change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion

§ 1788. Required Public Disclosures [Effective until July 1, 2015]

(a) Except as provided in subdivision (c), within 60 days after the cessation of a well stimulation treatment, the operator shall publicly disclose all of the following information:

(1) Operator's name;

(2) API number assigned to the well by the Division;

(3) Lease name and number of the well;

(4) Location of the well, submitted as a non-projected, Latitude Longitude, in the General Coordinate System (GCS) NAD83.

(5) County in which the well is located;

(6) Date that the well stimulation treatment occurred;

(7) True vertical depth of the well;

(8) Name and vertical depth of the productive horizon where well stimulation treatment occurred;

(9) The trade name, supplier, concentration, and a brief description of the intended purpose of each additive contained in the well stimulation fluids used;

(10) The total volume of base fluid used during the well stimulation treatment;

(11) Identification of whether the base fluid is water suitable for irrigation or domestic purposes, water not suitable for irrigation or domestic purposes, or a fluid other than water;

(12) The source, volume, and specific composition and disposition of all water associated with the well stimulation treatment, including, but not limited to, water used as base fluid and water recovered from the well following the well stimulation treatment that is not otherwise reported as produced water pursuant to Section 3227;

(13) Identification of any reuse of treated or untreated water for well stimulation treatments and well stimulation treatment-related activities;

(14) The specific composition and disposition of all well stimulation treatment fluids, including waste fluids, other than water;

(15) Any radiological components or tracers injected into the well as part of the well stimulation treatment, a description of the recovery method, if any, for those components or tracers, the recovery rate, and specific disposal information for recovered components or tracers;

(16) The radioactivity of the recovered well stimulation fluids;

(17) The location of the portion of the well subject to the well stimulation treatment and the extent of the fracturing or other modification, if any, surrounding the well induced by the treatment.

(18) The estimated volume of well stimulation treatment fluid that has been recovered; and

(19) A complete list of the names, Chemical Abstract Service numbers, and maximum concentration, in percent by mass, of each and every chemical constituent of the well stimulation treatment fluids used. If a Chemical Abstract Service number does not exist for a chemical constituent, the operator may provide another unique identifier, if available.

(b) For hydraulic fracturing well stimulation treatments, the operator shall post the information listed in subsection (a) to the Chemical Disclosure Registry, to the extent that the website is able to receive the information. For all well stimulation treatments, the operator shall provide all of the information listed in subsection (a) directly to the Division on the Well Stimulation Treatment Disclosure Reporting Form. The Well Stimulation Treatment Disclosure Reporting Form is available on the Division's public internet web- site at ftp://ftp.consrv.ca.gov/pub/oil/forms/Oil%26Gas/OG110S.XLSX. The Well Stimulation Treatment Disclosure Reporting Form shall be submitted to the Division in an electronic format, directed to the email address “DisclosureWST@conservation.ca.gov”.

(c) Except for items (1) through (6) of subsection (a), operators are not required to post information to the Chemical Disclosure Registry if the information is found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234. If information listed in subsection (a) is not posted to the Chemical Disclosure Registry on this basis, then the operator shall inform the Division in writing, specifying the information that is not being publicly disclosed. It is the operator's responsibility to post the information to the Chemical Disclosure Registry as soon as the information becomes public record under Public Resources Code section 3234.

(d) A claim of trade secret protection for the information required to be disclosed under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j).

(e) Groundwater quality data reported under this section shall also be submitted to the State Water Resources Control Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.

§ 1788. Required Public Disclosures [Effective July 1, 2015]

(a) Except as provided in subdivision (c), within 60 days after the cessation of a well stimulation treatment, the operator shall publicly disclose all of the following information:

(1) Operator's name;

(2) API number assigned to the well by the Division;

(3) Lease name and number of the well;

(4) Location of the well, submitted as a six-digit decimal degrees, non-projected, Latitude and Longitude, in the Geographic Coordinate System (GCS) NAD83.

(5) County in which the well is located;

(6) Date that the well stimulation treatment occurred;

(7) The measured and true vertical depth of the well;

(8) Formation name and vertical depth of the top and bottom of the productive horizon where well stimulation treatment occurred;

(9) The trade name, supplier, concentration, and a brief description of the intended purpose of each additive contained in the well stimulation fluids used;

(10) The total volume of base fluid used during the well stimulation treatment;

(11) Identification of whether the base fluid is water suitable for irrigation or domestic purposes, water not suitable for irrigation or domestic purposes, or a fluid other than water;

(12) The source, volume, and specific composition and disposition of all water associated with the well stimulation treatment, including all of the following:

(A) The source of the water used as a base fluid for the well stimulation treatment, including any of the following:

(i) The well or wells, if commingled, from which the water was produced or extracted;

(ii) The water supplier, if purchased from a supplier;

(iii) The point of diversion of surface water;

(B) Composition of water used as base fluid, including all of the following: total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A); benzene, toluene, ethyl benzene, and xylenes; major and minor cations (including sodium, potassium, magnesium, and calcium); major and minor anions (including nitrate, chloride, sulfate, alkalinity, and bromide); and trace elements (including lithium, strontium, and boron);

(C) Specific disposition of water recovered from the well following the well stimulation treatment, including method and location of disposal and, if the recovered water is injected into an injection well, identification of the operator, field, and project number of the injection project;

(D) Composition of water recovered from the well following the well stimulation treatment, sampled after a calculated wellbore volume has been produced back but before three calculated well- bore volumes have been produced back, and then sampled a second time after 30 days of production after the first sample is taken, with both samples taken prior to being placed in a storage tank or being aggregated with fluid from other wells;

(E) Composition of water recovered from the well following the well stimulation treatment shall be determined by testing the samples taken under paragraph (D) for all of the following: appropriate indicator compound(s) for the well stimulation treatment fluid; total dissolved solids; metals listed in California Code of Regulations, title 22, section 66261.24, subdivision (a)(2)(A) ; benzene, toluene, ethyl benzene, and xylenes; major and minor cations (including sodium, potassium, magnesium, and calcium); major and minor anions (including nitrate, chloride, sulfate, alkalinity, and bromide); and trace elements (including lithium, strontium, and boron); radium-226, gross alpha-beta, radon 222, fluoride, iron (redox), manganese (redox), H_2S (redox), nitrate+nitrite (redox), strontium, thallium, mercury, and methane;

(F) All testing results shall have a cover page briefly describing when and where sampling was done and the results of the testing;

(G) Sampling and testing conducted under subdivision (a)(12) is separate from and in addition to any sampling or testing that may be required to make hazardous waste determinations under the requirements of the Department of Toxic Substances Control;

(13) Identification of any reuse of treated or untreated water for well stimulation treatments and well stimulation treatment-related activities;

(14) The specific composition and disposition of all well stimulation treatment fluids, including waste fluids, other than water;

(15) Any radiological components or tracers injected into the well as part of the well stimulation treatment, a description of the recovery method, if any, for those components or tracers, the recovery rate, and specific disposal information for recovered components or tracers;

(16) The radioactivity of the recovered well stimulation fluids, and a brief description of the equipment and method used to determine the radioactivity;

(17) For each stage of the well stimulation treatment, the measured and true vertical depth of the location of the portion of the well subject to the well stimulation treatment and the extent of the fracturing or other modification, if any, surrounding the well induced by the treatment;

(18) The estimated volume of well stimulation treatment fluid that has been recovered; and

(19) A complete list of the names, Chemical Abstract Service numbers, and maximum concentration, in percent by mass, of each and every chemical constituent of the well stimulation treatment fluids used. If a Chemical Abstract Service number does not exist for a chemical constituent, the operator may provide another unique identifier, if available.

(b) For hydraulic fracturing well stimulation treatments, the operator shall post the information listed in subdivision (a) to the Chemical Disclosure Registry, to the extent that the website is able to receive the information. For all well stimulation treatments, the operator shall provide all of the information listed in subdivision (a) directly to the Division on the Well Stimulation Treatment Disclosure Reporting Form. The Well Stimulation Treatment Disclosure Reporting Form is available on the Division's public internet web- site at ftp://ftp.consrv.ca.gov/pub/oil/forms/Oil%26Gas/OG110S.XLSX. The Well Stimulation Treatment Disclosure Reporting Form shall be submitted to the Division in an electronic format, directed to the email address “DisclosureWST@conservation.ca.gov”. The Division will organize the information provided on Well Stimulation Treatment Disclosure Forms in a format, such as a spreadsheet, that allows the public to easily search and aggregate, to the extent practicable, each type of information disclosed.

(c) Except for the information specified in subdivision (a)(1) through (6), operators are not required to publicly disclose information found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234. If information listed in subdivision (a) is not publicly disclosed on this basis, then the operator shall inform the Division in writing, and provide the Division the information that is not being publicly disclosed. The Division will provide the information that is not publicly disclosed to other state agencies as needed for regulatory purposes and in accordance with a writ- ten agreement with the other state agency regarding sharing of confidential information. It is the operator's responsibility to publicly disclose the withheld information in the manner described in subdivision (b) as soon as the information becomes public record under Public Resources Code section 3234.

(d) A claim of trade secret protection for the information required to be disclosed under this section shall be handled in the manner specified under Public Resources Code section 3160, subdivision (j).

(e) Groundwater quality data reported under this section shall also be submitted to the Regional Water Board in an electronic format that follows the guidelines detailed in California Code of Regulations, title 23, chapter 30.

(f) If for any reason information specified in subdivision (a) cannot be collected within 60 days after the cessation of a well stimulation treatment, then the information shall still be publicly disclosed as soon as possible in the manner described in subdivision (b).

§ 1789. Post-Well Stimulation Treatment Report

(a) Within 60 days after the cessation of a well stimulation treatment, the operator shall submit a report to the Division describing:

(1) The pressures recorded during monitoring required under Section 1785(a) during the well stimulation treatment;

(2) The pressures recorded during the first 30 days of production pressure monitoring under Section 1787(d)(1);

(3) The date and time that each stage of the well stimulation treatment was performed;

(4) How the actual well stimulation treatment differs from what was anticipated in the well stimulation treatment design that was prepared under Section 1784(b);

(5) How the actual location of the well stimulation treatment differs from what was indicated in the permit application under Section 1783.1(a)(15); and

(6) A description of hazardous wastes generated during the well stimulation activities and their disposition, including copies of all hazardous waste manifests used to transport the hazardous wastes offsite to an authorized facility.

(b) If information found in a report submitted under this section is found in a well record that the Division has determined is not public record, pursuant to Public Resources Code section 3234, then the Division will provide the information to other state agencies as needed for regulatory purposes and in accordance with a written agreement with the other state agency regarding sharing of confidential information.

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9.1.6 Colorado

Regulatory Authority: Colorado Oil & Gas Conservation Commission

Reference Source: Oil and Gas Conservation Act of the State of Colorado

205A. HYDRAULIC FRACTURING CHEMICAL DISCLOSURE.

a. Applicability. This Commission Rule 205a applies to hydraulic fracturing treatments performed on or after April 1, 2012.

b. Required disclosures.

(1) Vendor and service provider disclosures. A service provider who performs any part of a hydraulic fracturing treatment and a vendor who provides hydraulic fracturing additives directly to the operator for a hydraulic fracturing treatment shall, with the exception of information claimed to be a trade secret, furnish the operator with the information required by subsection 205A.b.(2)(A)(viii) – (xii) and subsection 205A.b.(2)(B), as applicable, and with any other information needed for the operator to comply with subsection 205A.b.(2). Such information shall be provided as soon as possible within 30 days following the conclusion of the hydraulic fracturing treatment and in no case later than 90 days after the commencement of such hydraulic fracturing treatment.

(2) Operator disclosures.

A. Within 60 days following the conclusion of a hydraulic fracturing treatment, and in no case later than 120 days after the commencement of such hydraulic fracturing treatment, the operator of the well must complete the chemical disclosure registry form and post the form on the chemical disclosure registry, including:

i. the operator name;

ii. the date of the hydraulic fracturing treatment;

iii. the county in which the well is located;

iv. the API number for the well;

v. the well name and number

vi. the longitude and latitude of the wellhead;

vii. the true vertical depth of the well;

viii. the total volume of water used in the hydraulic fracturing treatment of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment, if something other than water;

ix. each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief descriptor of the intended use or function of each hydraulic fracturing additive in the hydraulic fracturing fluid;

x. each chemical intentionally added to the base fluid;

xi. the maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid; and

xii. the chemical abstract service numberfor each chemical intentionally added to the base fluid, if applicable.

B. If the vendor, service provider, or operator claim that the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical is/are claimed to be a trade secret, the operator of the well must so indicate on the chemical disclosure registry form and, as applicable, the vendor, service provider, or operator shall submit to the Director a Form 41 claim of entitlement to have the specific identity of a chemical, the concentration of a chemical, or both withheld as a trade secret. The operator must nonetheless disclose all information required under subsection 205A.b.(2)(A) that is not claimed to be a trade secret. If a chemical is claimed to be a trade secret, the operator must also include in the chemical registry form the chemical family or other similar descriptor associated with such chemical.

C. At the time of claiming that a hydraulic fracturing chemical, concentration, or both is entitled to trade secret protection, a vendor, service provider or operator shall file with the commission claim of entitlement, Form 41, containing contact information. Such contact information shall include the claimant's name, authorized representative, mailing address, and phone number with respect to trade secret claims. If such contact information changes, the claimant shall immediately submit a new Form 41 to the Commission with updated information.

D. Unless the information is entitled to protection as a trade secret, information submitted to the Commission or posted to the chemical disclosure registry is public information.

(3) Ability to search for information. The chemical disclosure registry shall allow the Commission staff and the public to search and sort the registry for Colorado information by geographic area, ingredient, chemical abstract service number, time period, and operator.

(4) Inaccuracies in information. A vendor is not responsible for any inaccuracy in information that is provided to the vendor by a third party manufacturer of the hydraulic fracturing additives. A service provider is not responsible for any inaccuracy in information that is provided to the service provider by the vendor. An operator is not responsible for any inaccuracy in information provided to the operator by the vendor or service provider.

(5) Disclosure to health professionals. Vendors, service companies, and operators shall identify the specific identity and amount of any chemicals claimed to be a trade secret to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a confidentiality agreement, Form 35. The written statement of need shall be a statement that the health professional has a

reasonable basis to believe that (1) the information is needed for purposes of diagnosis or treatment of an individual, (2) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (3) knowledge of the information will assist in such diagnosis or treatment. The confidentiality agreement, Form 35, shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the specific identity and amount of any chemicals claimed to be a trade secret are necessary for emergency treatment, the vendor, service provider, or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgement by the health professional that such information shall not be used for purposes other than the health needs asserted and that the health professional shall otherwise maintain the information as confidential. The vendor, service provider, or operator, as applicable, may request a written statement of need, and a confidentiality agreement, Form 35, from all health professionals to whom information regarding the specific identity and amount of any chemicals claimed to be a trade secret was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall in no way be construed as publicly available.

c. Disclosures not required. A vendor, service provider, or operator is not required to:

(1) disclose chemicals that are not disclosed to it by the manufacturer, vendor, or service provider;

(2) disclose chemicals that were not intentionally added to the hydraulic fracturing fluid; or

(3) disclose chemicals that occur incidentally or are otherwise unintentionally present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid.

d. Trade secret protection.

(1) Vendors, service companies, and operators are not required to disclose trade secrets to the chemical disclosure registry.

(2) If the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical are claimed to be entitled to protection as a trade secret, the vendor, service provider or operator may withhold the specific identity, the concentration, or both the specific identity and concentration, of the chemical, as the case may be, from the information provided to the chemical disclosure registry. Provided, however, operators must provide the information required by Rule 205A.b.(2)(B) & (C).

The vendor, service provider, or operator, as applicable, shall provide the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to the Commission upon receipt of a letter from the Director stating that such information is necessary to respond to a spill or release or a complaint from a person who may have been directly and adversely affected or aggrieved by such spill or release. Upon receipt of a written statement of necessity, such information shall be disclosed by the vendor, service provider, or operator, as applicable, directly to the Director or his or her designee and shall in no way be construed as publicly available.

The Director or designee may disclose information regarding the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to additional Commission staff members to the extent that such disclosure is necessary to allow the Commission staff member receiving the information to assist in responding to the spill, release, or complaint, provided that such individuals shall not disseminate the information further. In addition, the Director may disclose such information to any Commissioner, the relevant county public health director or emergency manager, or to the Colorado Department of Public Health and Environment’s director of environmental programs upon request by that individual. Any information so disclosed to the Director, a Commission staff member, a Commissioner, a county public health director or emergency manager, or to the

Colorado Department of Public Health and Environment's director of environmental programs shall at all times be considered confidential and shall not be construed as publicly available. The Colorado Department of Public Health and Environment's director of environmental programs, or his or her designee, may disclose such information to Colorado Department of Public Health and Environment staff members under the same terms and conditions as apply to the director.

316C. COGCC Form 42. FIELD OPERATIONS NOTICE

Operators shall submit a Form 42, Field Operations Notice, as designated below and in accordance with a Condition of Approval on any Form 2, Application for Permit to Drill; Form 2A, Oil and Gas Location Assessment; Form 4, Sundry Notice; Form 6, Well Abandonment Report; or any other approved form.

a. Notice of Intent to Conduct Hydraulic Fracturing Treatment. Operators shall give at least 48 hours advance written notice of intent to the Commission of a hydraulic fracturing treatment at any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Hydraulic Fracturing Treatment. The Commission shall provide prompt electronic notice of such intention to the relevant local governmental designee (LGD).

341. BRADENHEAD MONITORING DURING WELL STIMULATION OPERATIONS

The placement of all stimulation fluids shall be confined to the objective formations during treatment to the extent practicable.

During stimulation operations, bradenhead annulus pressure shall be continuously monitored and recorded on all wells being stimulated.

If at any time during stimulation operations the bradenhead annulus pressure increases more than 200 psig, the operator shall verbally notify the Director as soon as practicable, but no longer than 24 hours following the incident. A Form 42, Field Operations Notice, Notice of High Bradenhead Pressure During Stimulation shall be submitted by the end of the first business day following the event. Within fifteen

(15) days after the occurrence, the operator shall submit a Sundry Notice, Form 4, giving all details, including corrective actions taken.

If intermediate casing has been set on the well being stimulated, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded.

The operator shall keep all well stimulation records and pressure charts on file and available for inspection by the Commission for a period of at least five (5) years. Under Rule 502.b.(1), an operator may seek a variance from these bradenhead monitoring, recording, and reporting requirements under appropriate circumstances.

REPORTING

The COGCC rules and conditions of approval on drilling permits require that a number of notices and reports be submitted to the Commission. These include notification of the inspector 24 hours before drilling begins so that the inspector has an opportunity to witness operations.

The rules require the filing of a completion report (Form 5A) after hydraulic fracturing is completed. Other requirements relating to spill reporting, accidents and loss of well control are also specified in the rules.

The COGCC encourages operators to participate in reporting to FracFocus, the reporting system developed by the IOGCC and the Ground Water Protection Council (GWPC), where operators can report chemicals used during hydraulic fracturing on a well-by-well basis. The COGCC indicated that 35 percent of the operators in Colorado have contributed data to FracFocus so far this year. They encourage 100 percent participation. In August, Governor Hickenlooper directed the COGCC to develop a regulation that will provide for public disclosure of hydraulic fracturing chemicals.

WATER AND WASTE MANAGEMENT

The DWR in the DNR administers the program governing the use of water in Colorado. Water that is used for hydraulic fracturing must come from a legal source. It is typically purchased or leased from the holder of a water right.

The recycling of water produced during oil and gas operations is encouraged. Over 50% of hydraulic fracturing flowback water is recycled. Multi-well pits are provided for in Rules 903 and 907, with the intent of promoting recycling. All pits except certain drilling pits must be lined. Pipelines between multi-well pit locations are sometimes used to transfer water used for hydraulic fracturing

There are 290 Class II disposal wells in Colorado. Hydraulic fracturing fluid that is not recycled is disposed in Class II wells or evaporation pits, or at commercial disposal facilities. In addition, some E&P wastes, including hydraulic fracturing fluids, are transported between Colorado and the states of Wyoming, New Mexico, Utah, and Kansas. No hydraulic fracturing flowback water is discharged to surface waters.

9.1.7 Illinois

Illinois addresses stimulation under Part 245. Hydraulic Fracturing Regulatory Act (http://www.dnr.illinois.gov/OilandGas/Documents/ProposedHydraulicFracturing62-245.pdf).
This publication seems to be the most comprehensive fracturing regulations that have been examined in this report, both U.S. states, foreign countries, and API publications. Pertinent sections of the Act have been excerpted and included in this report. The complete document, 135 pages, can be found at the referenced website.

Regulatory Authority: Illinois Department of Natural Resources

Reference Source: Illinois Administrative Code, Title 62. Mining, Chapter I. Department of Natural Resources, Part 245. Hydraulic Fracturing Regulatory Act

Section 245.210 Permit Application Requirements

6) High Volume Horizontal Hydraulic Fracturing Operations Plan

A detailed description of the proposed high volume horizontal hydraulic fracturing operations, including, but not limited to, the following (Section 1-35(b)(6) of the Act):

> A) the formations affected by the high volume horizontal hydraulic fracturing operations, including, but not limited to, geologic name and geologic description of the formations that will be stimulated by the operation (Section 1-35(b)(6)(A) of the Act), and a description of the confining zone and the formations constituting or contributing to that zone, including, but not limited to, a description of the lithology, extent, thickness, permeability, porosity, transmissive faults, fractures, water or water source content, and susceptibility to vertical propagation of fractures, of the confining formations, if known after reasonable inquiry;
>
> B) the anticipated surface treating pressure range (Section 1- 35(b)(6)(B) of the Act);
>
> C) the maximum anticipated injection treating pressure (Section 1- 35(b)(6)(C) of the Act);

D) the estimated or calculated fracture pressure of the producing and confining zones (Section 1-35(b)(6)(D) of the Act);

E) the planned depth of all proposed perforations or depth to the top of the open hole section (Section 1-35(b)(6)(E) of the Act); and

F) the anticipated type, source and volume of the base fluid anticipated to be used in the high volume horizontal hydraulic fracturing treatment;

8) Chemical Disclosure Report

Unless the applicant documents to the Department's satisfaction why the information is not available at the time the application is submitted (in which case the applicant shall comply with Sections 245.700 and 245.720), a chemical disclosure report identifying each chemical and proppant anticipated to be used in hydraulic fracturing fluid for each stage of the high volume horizontal hydraulic fracturing operations, including the following (Section 1-35(b)(8) of the Act):

A) for each stage, the total volume of water anticipated to be used in the high volume horizontal hydraulic fracturing treatment of the well or the type and total volume of the base fluid anticipated to be used in the high volume horizontal hydraulic fracturing treatment, if something other than water (Section 1-35(b)(8)(A) of the Act);

B) each hydraulic fracturing additive anticipated to be used in the hydraulic fracturing fluid, including the trade name, vendor, a brief descriptor of the intended use or function of each hydraulic fracturing additive, and the Material Safety Data Sheet (MSDS), if applicable (Section 1-35(b)(8)(B) of the Act);

C) each chemical anticipated to be intentionally added to the base fluid, including, for each chemical, the Chemical Abstracts Service number, if applicable (Section 1-35(b)(8)(C) of the Act); and

D) the anticipated concentration in the base fluid, in percent by mass, of each chemical to be intentionally added to the base fluid (Section 1-35(b)(8)(D) of the Act);

11) Hydraulic Fracturing Fluids and Flowback Plan

A hydraulic fracturing fluids and flowback plan for the handling, storage, transportation, and disposal, recycling, or reuse of hydraulic fracturing fluids and hydraulic fracturing flowback consistent with the requirements of Subpart H. The plan shall identify the specific Class II injection well or wells that will be used to dispose of the hydraulic fracturing flowback or the facilities where the hydraulic fracturing flowback will be reused or recycled. The plan shall describe the capacity of the tanks to be used for the capture and storage of all the anticipated hydraulic fracturing flowback and of the lined reserve pit to be used, if necessary, to temporarily store any flowback in excess of the capacity of the tanks. Identification of the Class II injection well or wells shall be by name, identification number, and specific location and shall include the date of the most recent mechanical integrity test for each Class II injection well (Section 1- 35(b)(11) of the Act);

12) Well Site Safety Plan

A well site safety plan to:

A) address proper safety measures to be employed during high volume horizontal hydraulic fracturing operations for the protection of persons on the well site (Section 1-35(b)(12) of the Act) that complies with federal and State law;

B) address proper safety measures to be employed during high volume horizontal hydraulic fracturing operations for the protection of the general public (Section 1-35(b)(12) of the Act) that complies with federal and State law

C) identify the presence of any hazardous materials used or stored at the well site;

D) provide contact information for all appropriate emergency responders; and

E) provide contact information of the applicant to be used by emergency responders.

Section 245.250 Public and Governmental Notice by the Permit Applicant

2) Except as otherwise provided in this subsection (a)(2), applicants shall provide general public notice by publication, once each week for 2 consecutive weeks, beginning no later than 3 calendar days after submittal of the high volume horizontal hydraulic fracturing permit application to the Department, in a newspaper of general circulation published in or, if necessary, as near possible to each county where the well proposed for high volume horizontal hydraulic fracturing operations is proposed to be located. If a well is proposed for high volume horizontal hydraulic fracturing operations in a county where there is no daily newspaper of general circulation, applicant shall provide general public notice, by publication, once each week for 2 consecutive weeks, in a weekly newspaper of general circulation in that county beginning as soon as the publication schedule of the weekly newspaper permits, but in no case later than 10 days after submittal of the high volume horizontal hydraulic fracturing permit application to the Department. (Section 1-40(c)(2) of the Act)

SUBPART E: WELL CONSTRUCTION

Section 245.500 General Conditions and Requirements

a) All wells shall be constructed, and casing and cementing activities shall be conducted, in a manner that shall provide for control of the well at all times, prevent the migration of oil, gas, and other fluids into the fresh water and coal seams, and prevent pollution or diminution of fresh water. (Section 1-70(d) of the Act)

b) At any time, the Department, as it deems necessary, may require construction activities in addition to those required by this Part, including but not limited to, the installation of an additional cemented casing string or strings in the well. (Section 1-70(d)(15) of the Act)

Section 245.520 Cement Requirements

All cementing activities for well construction shall meet the requirements of this Section.

a) Cement must conform to the industry standards set forth in the document referenced in Section 245.115(a)(1). (Section 1-70(d)(4) of the Act).

b) Cement slurry must be prepared to minimize its free water content in accordance with the industry standards set forth in the document referenced in Section 245.115(a)(1). (Section 1-70(d)(4) of the Act).

c) Cement activities shall be designed and constructed in a manner to:

1) secure the casing in the wellbore (Section 1-70(d)(4)(A) of the Act);

2) isolate and protect fresh groundwater (Section 1-70(d)(4)(B) of the Act);

3) isolate abnormally pressured zones, lost circulation zones, and any potential flow zones, including hydrocarbon and fluid-bearing zones (Section 1-70(d)(4)(C) of the Act);

4) properly control formation pressure and any pressure from drilling, completion and production (Section 1-70(d)(4)(D) of the Act);

5) protect the casing from corrosion and degradation (Section 1-70(d)(4)(E) of the Act); and

6) prevent gas flow in the annulus (Section 1-70(d)(4)(F) of the Act).

d) For all cementing activities, the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus (Section 1-70(d)(7) of the Act).

e) Cement must be placed behind all surface, intermediate and production casing pursuant to the requirements of Sections 245.530, 245.560 and 245.570, respectively.

f) After the cement is placed behind the casing, the permittee shall wait on cement to set until the cement achieves a calculated compressive strength of at least 500 pounds per square inch, and a minimum of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer (Section 1-70(d)(8) of the Act).

g) Cement compressive strength tests must be performed on all cemented surface, intermediate, and production casing strings in accordance with the industry standards set forth in the document referenced in Section 245.115(a)(1):

1) the cement shall have a 72-hour compressive strength of at least 1,200 psi; and

2) the free water separation shall be no more than 6 milliliters per 250 milliliters of cement. (Section 1-70(d)(8) of the Act)

h) Cement job logs must be kept for all cementing activities pursuant to the following requirements:

1) Cement job logs shall provide information about the cementing activities as specified on a form to be prescribed by the Department, including, but not limited to:

A) dates of cementing;

B) source of the cement;

C) type of cement; and

D) amount used;

2) A copy of the cement job logs and cement compressive strength test results for all cemented surface, intermediate, and production casing strings in the well shall be maintained in the well file at the well site during drilling and high volume horizontal hydraulic fracturing operations and shall be made available to the Department upon request (Section 1-70(d)(9) of the Act);

3) Permittee shall provide the Department with a copy of all cement job logs and cement compressive strength test results 30 days after completion of cementing activities; and

4) Permittee shall retain these records for the life of the well until the well is plugged, abandoned and restored in accordance with the Illinois Oil and Gas Act, the administrative rules promulgated under that Act, and Subpart J of this Part.

Section 245.530 Surface Casing Requirements

Surface casing shall be used in the construction of all wells regulated by this Part and shall be set and cemented pursuant to the requirements of this Section.

a) Surface casing shall be used and set to a depth of at least 200 feet, or 100 feet below the base of the deepest fresh water, whichever is deeper. Surface casing must stop before reaching any hydrocarbon-bearing zones. (Section 1-70(d)(10) of the Act) If the surface casing does not protect all of the fresh water, intermediate casing shall be required.

b) Surface casing must be made of steel and conform to the industry standards set forth in the document referenced in Section 245.115(a)(2). Additionally, the use of surface casing in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(2). (Section 1-70(d)(1) of the Act)

c) Casing thread compound must conform to and meet all manufacturing and material requirements of the industry standards set forth in the document referenced in Section 245.115(a)(3) (Section 1-70(d)(2) of the Act). Additionally, the uses of casing thread compound in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(3).

d) The borehole must be circulated and conditioned before surface casing setting and cementing to ensure an adequate cement bond (Section 1-70(d)(5) of the Act).

e) The permittee shall notify the Department's District Office during normal business hours by phone and electronic mail at least 24 hours (Section 1- 70(d)(11) of the Act) before setting and cementing surface casing to enable an inspector to be present.

f) When setting surface casing, centralizers are required to be used as follows to keep the casing in the center of the wellbore before and during cement operations:

1) A centralizer shall be placed at the bottom of the surface casing string or shoe;

2) Centralizers shall be placed above and below a stage collar or diverting tool, if run;

3) Centralizers shall be placed through usable-quality water zones;

4) Centralizers shall be placed on every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar;

5) The Department may require additional centralization as necessary to ensure the integrity of the well design is adequate; and

6) All centralizers must conform to and shall meet specifications in, or equivalent to, the industry standards set forth in the documents referenced in Section 245.115(a)(4) through (a)(6).

g) A pre-flush or spacer must be pumped ahead of the cement. (Section 1-70(d)(6) of the Act)

h) Surface casing cement must:

1) be Class A cement, with a minimum density of 14.5 lbs./gal.;

2) meet the cement requirements of Section 245.520(a) and (b); and

3) be applied behind the casing according to the requirements of Section 245.520(c) and (d).

i) Surface casing must be fully cemented to the surface with excess cements. Cementing must be by the pump and plug method with a minimum of 25% excess cement with appropriate lost circulation material, unless another amount of excess cement is approved by the Department. If cement returns are not observed at the surface, the permittee must perform remedial actions as appropriate. (Section 1-70(d)(11) of the Act)

j) After the cement is placed behind the surface casing (Section 1-70(d)(8) of the Act), the cement must be tested (comprehensive strength test) and cement job logs maintained pursuant to the requirements of Section 245.520(f) through (h).

k) After the surface casing cement operation is completed to the surface, the permittee shall notify the Department's District Office by phone and electronic mail to enable an inspector to be present for the following:

1) testing the internal mechanical integrity of the surface casing pursuant to Section 245.540; and

2) installation and testing of the blowout prevention equipment pursuant to Section 245.550.

Section 245.540 Establishment of Internal Mechanical Integrity

An internal mechanical integrity test shall be performed on each cemented casing string after installation for all wells regulated by this Part.

a) The permittee shall contact the Department's District Office during normal business hours by phone and electronic mail at least 24 hours before conducting an internal mechanical integrity pressure test to enable an inspector to be present when the test is performed (Section 1-70(d)(16) of the Act).

b) Mechanical Integrity

1) The internal mechanical integrity of surface and intermediate casing strings shall be tested:

A) with fresh water or brine;

B) to no less than 0.22 psi per foot of casing string length or 1,500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield; and

C) for at least 30 minutes with less than a 5% pressure loss.

2) If the pressure declines more than 5% or if there are other indications of a leak, corrective action shall be taken before conducting further drilling operations. (Section 1-70(d)(16) of the Act)

c) The internal mechanical integrity of the production casing string or any casing string that will have pressure exerted on it during stimulation of the well shall be tested:

1) with fresh water or brine;

2) to at least the maximum anticipated treatment pressure or 1,500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield;

3) for at least 30 minutes with less than a 5% pressure loss; and

4) if the pressure declines more than 5% or if there are other indications of a leak, corrective action shall be taken before conducting further drilling operations. (Section 1-70(d)(16) of the Act)

d) Records of internal mechanical integrity pressure tests for all casing strings must be kept pursuant to the following requirements:

1) A record of the internal mechanical integrity pressure test for each casing string must be maintained by the permittee in the well file at the well site and must be submitted to the Department on a form prescribed by the Department before conducting high volume horizontal hydraulic fracturing operations (Section 1-70(d)(16) of the Act).

2) Permittee shall provide the Department with a copy of all internal mechanical integrity pressure test results for all casing strings 30 days after completion of well construction; and

3) Permittee shall retain these records for the life of the well until the well is plugged, abandoned and restored in accordance with the Illinois Oil and Gas Act, the administrative rules promulgated under that Act, and Subpart J of this Part.

Section 245.560 Intermediate Casing Requirements

When intermediate casing is required by subsection (a), intermediate casing used in the construction of wells must be set and cemented pursuant to the requirements of subsections (b) through (m). Intermediate casing used to isolate fresh water must not be used as the production string in the well in which it is installed, and may not be perforated for purposes of conducting a hydraulic fracture treatment through it.

a) Cemented intermediate casing must be installed under the following conditions:

1) when necessary to isolate fresh water not isolated by surface casing; or

2) to seal off potential flow zones, anomalous pressure zones, lost circulation zones and other drilling hazards. (Section 1-70(d)(12) of the Act)

b) Intermediate casing shall be set and cemented to one of the standards below:

1) When intermediate casing is installed to protect fresh water, the permittee shall set a full string of new intermediate casing at least 100 feet below the base of the deepest fresh water and bring cement to the surface;

2) In instances in which intermediate casing was set solely to protect fresh water encountered below the surface casing shoe, and cementing to the surface is technically infeasible, would result in lost circulation, or both, cement must be brought to a minimum of 600 feet above the shallowest fresh water zone encountered below the surface casing shoe or to the surface if the fresh water zone is less than 600 feet from the surface;

3) In the case that intermediate casing was set for a reason other than to protect fresh water, the intermediate casing string shall be cemented from the shoe to a point at least 600 true vertical feet above the shoe; or

4) If there is a hydrocarbon bearing zone that is capable of producing and that is exposed above the intermediate casing shoe, then the casing shall be cemented from the shoe:

A) to a point at least 600 true vertical feet above the shallowest hydrocarbon bearing zone;

B) to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well; or

C) to the surface if less than 200 feet. (Section 1-70(d)(12) of the Act)

c) The location and depths of any hydrocarbon-bearing zones or fresh water zones that are open to the wellbore above the casing shoe must be confirmed by coring, electric logs, or testing and must be reported to the Department. (Section 1- 70(d)(12) of the Act)

d) Intermediate casing must conform to the industry standards set forth in the document referenced in Section 245.115(a)(2). Additionally, the use of intermediate casing in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(2).

e) Casing thread compound must conform to and meet all manufacturing and material requirements of the industry standards set forth in the document referenced in Section 245.115(a)(3) (Section 1-70(d)(2) of the Act). Additionally, the uses of casing thread compound in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(3).

f) The borehole must be circulated and conditioned before intermediate casing setting and cementing to ensure an adequate cement bond (Section 1-70(d)(5) of the Act).

g) The permittee shall notify the Department's District Office during normal business hours by phone and electronic mail at least 24 hours before setting and cementing intermediate casing cementing operations to enable an inspector to be present.

h) When setting intermediate casing in non-deviated holes, centralizers are required to be used as follows to keep the casing in the center of the wellbore before and during cementing operations:

1) Centralizers shall be placed on every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar;

2) The Department may require additional centralizers as necessary to ensure the integrity of the well design; and

3) All centralizers must conform to and shall meet specifications in, or equivalent to, the industry standards set forth in the documents referenced in Section 245.115(a)(4) through (a)(6). (Section 1-70(d)(3) of the Act)

i) A pre-flush or spacer must be pumped ahead of the cement (Section 1-70(d)(6) of the Act).

j) Intermediate casing cement must:

1) meet the cement requirements of Section 245.520(a) and (b); and

2) be applied behind the casing according to the requirements of Section 245.520(c) and (d).

k) A radial cement bond evaluation log, or other evaluation approved by the Department, such as, but not limited to, temperature surveys, must be run to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead. (Section 1-70(d)(13) of the Act)

l) The cementing and testing requirements of subsections (b)(2), (b)(3), (b)(4), (c) and (k) may be waived if all intermediate casing strings are cemented to surface.

m) After the cement is placed behind the intermediate casing (Section 1-70(d)(8) of the Act), the cement must be tested and cement job logs maintained pursuant to the requirements of Section 245.520(f) through (h).

n) After the intermediate casing cement operation is completed, the permittee shall notify the Department's District Office by phone and electronic mail to enable an inspector to be present for testing the internal mechanical integrity of the intermediate casing pursuant to Section 245.540.

o) If the annulus between the production casing and the surface of intermediate casing has not been cemented to the surface, the intermediate casing annulus shall be equipped with an appropriately sized and tested relief valve. The flow line from the relief valve should be secured and diverted to a lined pit or tank. (See API HF1 – Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, 1st Edition, October 2009, Section 10.4.2, Pressure Monitoring.)

Section 245.570 Production Casing Requirements

Production casing shall be used in the construction of all wells regulated by this Part and shall be set and cemented pursuant to the requirements of this Section.

a) Production casing must be fully cemented from the production casing shoe to 500 feet above the top perforated formation, if possible (Section 1-70(d)(14) of the Act). However, if that cementing requirement will inhibit the production of oil or gas from the targeted formation, cementing of the production casing must be completed from at least just above the top of the perforated formation to 500 feet above the top of the perforated formation.

b) Production casing must conform to the industry standards set forth in the document referenced in Section 245.115(a)(2). Additionally, the use of production casing in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(2).

c) Casing thread compound must conform to and meet all manufacturing and material requirements of the industry standards set forth in the document referenced in Section 245.115(a)(3) (Section 1-70(d)(2) of the Act). Additionally, the uses of casing thread compound in the well construction must be in a manner consistent with the industry standards set forth in the document referenced in Section 245.115(a)(3).

d) The borehole must be circulated and conditioned before production casing setting and cementing to ensure an adequate cement bond (Section 1-70(d)(5) of the Act).

e) The permittee shall notify the Department's District Office during regular business hours by phone and electronic mail before setting and cementing production casing to enable an inspector to be present.

f) When setting production casing, centralizers are required to be used as follows to keep the casing in the center of the wellbore prior to and during cement operations:

> 1) In the vertical portion of the well, a centralizer shall be placed on every fourth joint from the kickoff point to the ground surface or to the bottom of the cellar;
>
> 2) In the horizontal portion of the well, rigid centralizers shall be used and placed accordingly to ensure at least 80% standoff;
>
> 3) The Department may require additional centralizers as necessary to ensure the integrity of the well design; and
>
> 4) All centralizers used in the vertical portion of the well must conform to and shall meet specifications in, or equivalent to the industry standards set forth in the documents referenced in Section 245.115(a)(4) through (a)(6). (Section 1-70(d)(3) of the Act)

g) A pre-flush or spacer must be pumped ahead of the cement (Section 1-70(d)(6) of the Act).

h) Production casing cement must:

> 1) meet the cement requirements of Section 245.520(a) and (b); and

2) be applied behind the casing according to the requirements of Section 245.520(c) and (d).

i) After the cement is placed behind the production casing (Section 1-70(d)(8) of the Act), the cement must be tested and cement job logs maintained pursuant to the requirements of Section 245.520(f) through (h).

j) After the production casing cement operation is completed, the permittee shall notify the Department's District Office by phone or electronic mail to enable an

inspector to be present for testing the internal mechanical integrity of the production casing pursuant to Section 245.540.

Section 245.580 Establishment of Formation Integrity

a) A formation pressure integrity test shall be conducted below the surface casing and below all intermediate casing in order to demonstrate:

1) that the integrity of the casing shoe is sufficient to contain the wellbore pressures anticipated in the permit application;

2) that no flow path exists to formations above the casing shoe; and

3) that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down.

b) The permittee shall notify the Department's District Office during regular business hours by phone and electronic mail at least 24 hours before conducting a formation pressure integrity test to enable an inspector to be present when the test is performed.

c) The actual hydraulic fracturing treatment pressure must not exceed the mechanical integrity test pressure of the casing tested pursuant to Section 245.540 at any time during high volume horizontal hydraulic fracturing operations.

d) Records of all formation integrity tests must be kept pursuant to the following requirements:

1) A record of the formation integrity test must be maintained by the permittee in the well file at the well site and must be submitted to the Department on a form prescribed by the Department before conducting high volume horizontal hydraulic fracturing operations. (Section 1- 70(d)(18) of the Act)

2) Permittee shall provide the Department with a copy of all formation integrity test results 30 days after completion of well construction.

3) Permittee shall retain these records for the life of the well until the well is plugged, abandoned and restored in accordance with the Illinois Oil and Gas Act, the administrative rules promulgated under that Act, and Subpart J of this Part.

SUBPART F: WATER QUALITY

Section 245.600 Water Quality Monitoring

Water quality monitoring shall be conducted pursuant to the requirements of this Section and in accordance with the water quality monitoring work plan submitted pursuant to Section 245.210(a)(24). Unless specified otherwise, all distances are measured horizontally from the closest edge of the well site.

b) Baseline Testing

Before conducting high volume horizontal hydraulic fracturing operations on a well, a permittee shall retain an independent third party, as identified pursuant to subsection (a)(3). The permittee, through its independent third party, shall, after giving the Department 7 calendar days' notice during regular business hours, conduct baseline water quality sampling of all water sources within 1,500 feet of the well site (Section 1-80(b) of the Act) pursuant to the laboratory analysis procedures of subsection (d) and as follows:

1) If an aquifer to be sampled is inaccessible through groundwater wells within 1,500 feet of the well site, the permittee shall conduct groundwater well sampling of that aquifer at the next closest groundwater well that the permittee has permission to access.

2) Installation of a groundwater monitoring well is not required to satisfy the sampling requirements of this Section.

3) Baseline testing results shall be submitted to the Department no later than 3 calendar days before commencing high volume horizontal hydraulic fracturing operations, unless there are non-disclosure agreements with the applicable private property landowners. In the case of non-disclosure agreements, the permittee shall provide a certification to the Department that the baseline testing results have been provided to the applicable private property landowners no later than 3 calendar days before commencing high volume horizontal hydraulic fracturing operations.

4) The Department shall post the results of the baseline sampling and analysis conducted under this subsection (b) on its website within 7 calendar days after receipt. The posted results shall, at a minimum, include the following:

A) the well name, location and permit number;

B) a detailed description of the sampling and testing conducted under this subsection (b), including the results of the sampling and testing;

C) the chain of custody of the samples;

D) quality control of the testing. (Section 1-80(b) of the Act)

c) Follow-up MonitoringAfter baseline tests are conducted under subsection (b) and following the completion of high volume horizontal hydraulic fracturing operations, the permittee, through its independent third party, shall perform the following:

1) Notify the Department during normal business hours at least 7 calendar days prior to taking the samples; and

2) Sample and test all water sources that were subjected to sampling under subsection (b) in the same manner following the procedures under subsection (d) 6 months, 18 months, and 30 months after the high volume horizontal hydraulic fracturing operations have been completed, unless the water source was sampled under this subsection (c) or subsection (b) within the previous month. (Section 1-80(c) of the Act)

Section 245.630 Prohibitions

It is unlawful to inject or discharge hydraulic fracturing fluid, produced water, BTEX, diesel, or petroleum distillates into fresh water (Section 1-25(c) of the Act).

SUBPART G: CHEMICAL DISCLOSURE; TRADE SECRETS

Section 245.700 Chemical Disclosure by Permittee

a) If the chemical disclosure information required by Section 245.210(a)(8) is not submitted at the time of permit application, then the permittee shall submit this information to the Department in electronic format no less than 21 calendar days before performing the high volume horizontal hydraulic fracturing operations (Section 1-77(a) of the Act).

b) Nothing in this Section shall prohibit the permittee from adjusting or altering the contents of the fluid during the treatment process to respond to unexpected conditions, as long as the permittee notifies the Department by electronic mail within 24 hours of the departure from the initial treatment design and includes a brief explanation detailing the reason for the departure (Section 1-77(a) of the Act).

c) No less than 21 calendar days before performing the first stimulation treatment of high volume horizontal hydraulic fracturing operations, the permittee shall maintain and disclose to the Department separate and up-to-date master lists of (Section 1-77(c)(2) of the Act):

1) the base fluid to be used during any high volume horizontal hydraulic fracturing operations within this State (Section 1-77(c)(2)(A) of the Act);

2) all hydraulic fracturing additives to be used during any high volume horizontal hydraulic fracturing operations within this State (Section 1- 77(c)(2)(B) of the Act); and

3) all chemicals and associated Chemical Abstract Service numbers to be used in any high volume horizontal hydraulic fracturing operations within this State (Section 1-77(c)(2)(C) of the Act).

d) If a permittee uses the services of another person to perform high volume horizontal hydraulic fracturing operations, that person shall comply with Section 245.710 (Section 1-77(b) of the Act).

Section 245.710 Chemical Disclosure by Contractor

a) A permittee shall be responsible to ensure that any contractor performing high volume horizontal hydraulic fracturing operations within this State on behalf of the permittee shall (Section 1-77(c) of the Act):

1) be authorized to do business in this State (Section 1-77(c)(1) of the Act);

2) provide the Department with the following information:

A) the contractor's business name, address, email address and telephone number;

B) the well name, permit number and permittee name for the well on which high volume horizontal hydraulic fracturing operations will be conducted; and

C) the name, email address and telephone number of the person at the well site responsible for the high volume horizontal hydraulic fracturing operations.

b) No less than 21 calendar days before performing the first stimulation treatment of high volume horizontal hydraulic fracturing operations, the contractor performing high volume horizontal hydraulic fracturing operations on behalf of the permittee shall maintain and disclose to the Department separate and up-to-date master lists of (Section 1-77(c)(2) of the Act):

1) the base fluid to be used during any high volume horizontal hydraulic fracturing operations within this State (Section 1-77(c)(2)(A) of the Act);

2) all hydraulic fracturing additives to be used during any high volume horizontal hydraulic fracturing operations within this State (Section 1- 77(c)(2)(B) of the Act); and

3) all chemicals and associated Chemical Abstract Service numbers to be used in any high volume horizontal hydraulic fracturing operations within this State (Section 1-77(c)(2)(C) of the Act).

Section 245.715 Chemical Use Prohibitions

a) The permittee performing high volume horizontal hydraulic fracturing operations is prohibited from using any base fluid, hydraulic fracturing additive, or chemical not listed on their master lists disclosed under Section 245.700.

b) Contractors performing high volume horizontal hydraulic fracturing operations are prohibited from using any base fluid, hydraulic fracturing additive, or chemical not listed on their master lists disclosed under Section 245.710. (Section 1-77(d) of the Act)

Section 245.720 Department Publication of Chemical Disclosures and Claims of Trade Secret

a) The Department shall assemble and post up-to-date copies of the master lists of chemicals it receives under Sections 245.700 and 245.710 on its website within 21 business days after receipt (Section 1-77(e) of the Act).

b) When an applicant, permittee, or person performing high volume horizontal hydraulic fracturing operations furnishes chemical disclosure information to the Department under

Section 245.210, 245.700, 245.710 or 245.860 under a claim of trade secret, the applicant, permittee, or person performing high volume horizontal hydraulic fracturing operations shall submit redacted and un-redacted copies of the documents identifying the specific information on the master list of chemicals claimed to be protected as trade secret. The Department shall use the redacted copies when posting the master list of chemicals on its website. (Section 1-77(f) of the Act)

c) Upon submission or within 5 calendar days after submission of the master list of chemicals with chemical disclosure information to the Department under Section 245.210, 245.700, 245.710 or 245.860 under a claim of trade secret, the person that claimed trade secret protection shall provide a justification of the claim containing the following:

1) a detailed description of the procedures used by the person to safeguard that portion of the information on the master list of chemicals for which trade secret is claimed from becoming available to persons other than those selected by the person to have access to the information for limited purposes;

2) a detailed statement identifying the persons or class of persons to whom that portion of the information on the master list of chemicals for which trade secret is claimed has been disclosed;

3) a certification that the person has no knowledge that the portion of the information on the master list of chemicals for which trade secret is claimed has ever been published or disseminated or has otherwise become a matter of general public knowledge;

4) a detailed discussion of why the person believes that the portion of the information on the master list of chemicals for which trade secret is claimed is of competitive value; and

5) any other information that shall support the claim of trade secret. (Section 1-77(g) of the Act)

d) Chemical disclosure information furnished under Section 245.210, 245.700, 245.710 or 245.860 under a claim of trade secret shall be protected from disclosure as a trade secret if the Department determines that the statement of justification demonstrates that (Section 1-77(h) of the Act):

1) the information has not been published, disseminated, or otherwise become a matter of general public knowledge (Section 1-77(h)(1) of the Act). There is a rebuttable presumption that the information has not been published, disseminated, or otherwise become a matter of general public knowledge if the person has taken reasonable measures to prevent the information from becoming available to persons other than those selected by the person to have access to the information for limited purposes and the statement of justification contains a certification that the person has no knowledge that the information has ever been published, disseminated, or otherwise become a matter of general public knowledge (Section 1- 77(h) of the Act); and

2) the information has competitive value (Section 1-77(h)(2) of the Act).

e) Denial of a trade secret request under this Section shall be appealable under the Administrative Review Law (Section 1-77(i) of the Act) and the rules adopted under that Law.

f) A person whose request to inspect or copy a public record is denied, in whole or in part, because of a grant of trade secret protection may file a request for review with the Public Access Counselor under Section 9.5 of the Freedom of Information Act [5 ILCS 140] or for injunctive or declaratory relief under Section 11 of the Freedom of Information Act for the purpose of reviewing whether the Department properly determined that the trade secret protection should be granted (Section 1-77(j) of the Act).

g) Except as otherwise provided in Section 245.730 of this Part and Section 1-77(m) of the Act, the Department must maintain the confidentiality of chemical disclosure information furnished under Section 245.210, 245.700, 245.710 or 245.860 under a claim of trade secret, until the Department receives official notification of a final order by a reviewing body with proper jurisdiction that is not subject to further appeal rejecting a grant of trade secret protection for that information (Section 1-77(k) of the Act).

Section 245.730 Trade Secret Disclosure to Health Professional

Information about high volume horizontal hydraulic fracturing treatment chemicals furnished under a claim of trade secret may be disclosed by the Department to a health professional for the limited purpose of determining what health care services are necessary for the treatment of an affected patient pursuant to the requirements of this Section.

a) A health professional shall complete and submit a request to obtain trade secret chemical information. In the request, the health professional shall:

1) state a need for the information and articulate why the information is needed;

2) identify whether the affected patient requires emergency or non- emergency health care services; and

3) identify the name and profession of the health professional and the name and location of the facility where the affected patient is being treated.

b) In an emergency health care situation, a health professional shall:

1) call the Department during normal business hours and, as soon as circumstances permit without impeding the treatment of the affected patient, submit a completed request for information to the Department

online or by fax. The Department shall respond to the health professional as quickly as possible by telephone, fax or other methods determined by the Department to be a secure means of disclosure; or

2) call the trade secret holder at any time (24 hours/7 days a week) and, as soon as circumstances permit without impeding the treatment of the affected patient, submit a completed request for information to the trade secret holder directly by fax or email. The trade secret holder shall respond to the health professional as quickly as possible,

but in no case more than 2 hours, by telephone, fax or other methods determined by the trade secret holder to be a secure means of disclosure.

c) In a non-emergency health care situation, a health professional shall:

1) call the Department during normal business hours and submit a completed request for information to the Department online or by fax. The Department shall respond to the health professional within 2 business days by fax or other methods determined by the Department to be a secure means of disclosure; or

2) call the trade secret holder at any time (24 hours/7 days a week) and submit a completed request for information to the trade secret holder directly by fax or email. The trade secret holder shall respond to the health professional within the same business day by fax or other methods determined by the trade secret holder to be a secure means of disclosure.

d) The health professional may share information disclosed pursuant to this Section with other persons as may be professionally necessary, including, but not limited to, the affected patient, other health professionals involved in the treatment of the affected patient, the affected patient's family members if the affected patient is unconscious, unable to make medical decisions, or is a minor, the Centers for Disease Control and Prevention, and other government public health agencies.

e) As soon as circumstances permit, the health professional who submitted the request for information shall inform the holder of the trade secret the names of all other health professionals to whom the information was disclosed.

f) As soon as circumstances permit without impeding the treatment of the affected patient, the holder of the trade secret may request a confidentiality agreement consistent with the requirements of this Section from all health professionals to whom the information is disclosed.

g) Any recipient of the information disclosed pursuant to this Section shall not use the information for purposes other than the health needs asserted in the request and shall otherwise maintain the information as confidential. Information so disclosed to a health professional shall in no way be construed as publicly available. (Section 1-77(l) of the Act)

SUBPART H: HIGH VOLUME HORIZONTAL HYDRAULIC FRACTURING PREPARATIONS AND OPERATIONS

Section 245.800 General Conditions and Requirements

a) During all phases of high volume horizontal hydraulic fracturing operations, the permittee shall comply with all terms of the permit, the Act and this Part (Section 1-75(a)(1) of the Act).

b) All phases of high volume horizontal hydraulic fracturing operations shall be conducted in a manner that shall not pose a significant risk to public health, life, property, aquatic life, or wildlife (Section 1-75(a)(2) of the Act).

Section 245.805 Hydraulic Fracturing String Requirements and Pressure Testing

Hydraulic fracturing strings, if used in any wells regulated by this Part, shall be set or reset pursuant to the requirements of this Section.

a) Hydraulic fracturing strings must be either strung into a production liner or run with a packer set at least 100 feet below the deepest cement top.

b) A function-tested relief valve and diversion line must be installed and used to divert flow from the hydraulic fracturing string-casing annulus to a covered watertight steel tank in case of hydraulic fracturing string failure.

1) The relief valve must be set to limit the annular pressure to no more than 95% of the working pressure rating of the weakest casings forming the annulus.

2) The annulus between the hydraulic fracturing string and the production or immediate casing must be pressurized to at least 250 psi and monitored.

c) Hydraulic fracturing strings must be tested to not less than the maximum anticipated treating pressure minus the annulus pressure applied between the fracturing string and the production or immediate casing. The pressure test shall be considered successful if the pressure applied has been held for 30 minutes with no more than 5% pressure loss. (Section 1-70(d)(17) of the Act)

d) The permittee shall notify the Department's District Office during regular business hours by phone and electronic mail at least 24 hours before conducting a pressure test of the hydraulic fracturing string to enable an inspector to be present when the test is performed.

e) A record of the pressure test shall be made on a form prescribed by the Department, maintained by the permittee in the well file at the well site, and made available to the Department upon request and included in the high volume horizontal hydraulic fracturing operations completion report pursuant to Section 245.860(d).

f) If any change to the well involving resetting, repositioning, reconnecting or breaking any pressure connection of the hydraulic fracturing string occurs after a stage of high volume horizontal hydraulic treatment, the pressure test requirements of subsections (c) through (e) must be successfully repeated before initiating any subsequent stage of high volume horizontal hydraulic fracturing treatment.

Section 245.810 Surface Equipment Pressure Testing

For all wells regulated by this Part, the final configuration of surface equipment associated with the high volume horizontal hydraulic fracturing treatment, including the injection lines and manifold, associated valves, fracture head or tree and any other wellhead components or connections, must be pressure tested pursuant to the requirements of this Section before any pumping of hydraulic fracturing fluid.

a) The permittee shall notify the Department's District Office during regular business hours by phone and electronic mail at least 24 hours before conducting a pressure test of the final configuration of the surface equipment used for the high volume horizontal hydraulic fracturing treatment to enable an inspector to be present when the test is performed.

b) The final configuration of the surface equipment used for the high volume horizontal hydraulic fracturing treatment must be pressure tested with fresh water or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss.

c) A record of the pressure test must be made on a form prescribed by the Department, maintained by the permittee in the well file at the well site, and made available to the Department upon request. (Section 1-75(b)(2) of the Act)

d) If the configuration of surface equipment used for the high volume horizontal hydraulic fracturing treatment has been reconfigured or changed in any manner that breaks any pressure connection after a stage of high volume horizontal hydraulic fracturing operations treatment, the pressure test requirements of subsections (a) through (c) must be successfully repeated before initiating any subsequent stage of high volume horizontal hydraulic fracturing operations.

Section 245.815 Notice and Approval Before Commencement of High Volume Horizontal Hydraulic Fracturing Operations

Before commencement of high volume horizontal hydraulic fracturing operations, the permittee must notify and receive written approval from the Department by U.S. mail or electronic mail. Department approval for high volume horizontal hydraulic fracturing operations shall be based on the permittee's compliance with the following:

a) The permittee shall notify the Department's District Office during regular business hours by phone and electronic mail or letter at least 48 hours before the commencement of high volume horizontal hydraulic fracturing operations to enable an inspector to be present (Section 1-75(a)(3) of the Act). The notification under this subsection shall be notice for all stages of a multiple-stage high volume horizontal hydraulic fracturing treatment.

b) Prior to conducting high volume horizontal hydraulic fracturing operations at a well site, the permittee shall cause to be plugged all previously abandoned unplugged or insufficiently plugged well bores within 750 feet of any part of the horizontal well bore that penetrated within 400 vertical feet of the geologic formation that will be stimulated as part of the high volume horizontal hydraulic fracturing operations pursuant to the requirements of Section 245.1010 (Section 1-95(b) of the Act).

c) Baseline water quality sampling of all water sources within 1,500 feet of the well site must be completed pursuant to Section 245.600(b).

d) All tests required by the following Sections shall be conducted:

1) Section 245.540: well casing internal mechanical integrity tests (see Sections 1-75(b)(1) and 1-70(d)(16) of the Act);

2) Section 245.580: formation integrity tests (see Sections 1-75(b)(1) and 1- 70(d)(18) of the Act);

3) Section 245.805: hydraulic fracturing string pressure tests, if required (see Sections 1-75(b)(1) and 1-70(d)(17) of the Act) ; and

4) Section 245.810: surface equipment pressure tests (see Section 1-75(b)(2) of the Act).

Section 245.820 Secondary Containment Inspections

No more than one hour before initiating any stage of the high volume horizontal hydraulic fracturing operations, all secondary containment required pursuant to Section 245.825(b) must be visually inspected by the permittee or the contractor performing the high volume horizontal hydraulic fracturing operations on behalf of the permittee to ensure that all structures and equipment are in place and in proper working order. The results of this inspection must be recorded and documented by the permittee or the contractor performing the high volume horizontal hydraulic fracturing operations on behalf of the permittee on a form prescribed by the Department, maintained in the well file at the well site, and available to the Department upon request. (Section 1-75(c)(13) of the Act)

Section 245.825 General Fluid Storage

In accordance with the approved hydraulic fracturing fluid and flowback plan required by Section 245.210(a)(11) and the approved containment plan required by Section 245.210(a)(13), and except as provided in Section 245.830, hydraulic fracturing additives, hydraulic fracturing fluid, hydraulic fracturing flowback, and produced water shall be stored in above-ground tanks pursuant to the requirements of this Section at all times until removed for proper disposal or recycling (Section 1-75(c)(1) and (c)(2) of the Act).

a) Above-ground tanks must be:

1) closed, watertight, vented in compliance with Section 245.910, and corrosion-resistant (Section 1-75(c)(4) of the Act);

2) constructed of materials compatible with the composition of the hydraulic fracturing fluid, hydraulic fracturing flowback, and produced water (Section 1-70(b)(3) of the Act);

3) of sufficient pressure rating (Section 1-75(c)(6) of the Act);

4) maintained in a leak-free condition (Section 1-75(c)(6) of the Act); and

5) routinely inspected for corrosion (Section 1-75(c)(4) of the Act).

b) Secondary containment is required for all above-ground tanks and additive staging areas.

1) Secondary containment measures may include one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps, or other structures or equipment capable of containing the substance within the well site.

2) Any secondary containment must be sufficient to contain 150% of the total capacity of the single largest container or tank within a common containment area. (Section 1-75(c)(13) of the Act)

c) Piping, conveyances, valves in contact with hydraulic fracturing fluid, hydraulic fracturing flowback, or produced water must be (Section 1-70(b)(3) of the Act):

1) constructed of materials compatible with the expected composition of the hydraulic fracturing fluid, hydraulic fracturing flowback, and produced water (Section 1-70(b)(3) of the Act);

2) of sufficient pressure rating (Section 1-75 (c)(6) of the Act);

3) able to resist corrosion (Section 1-75(c)(6) of the Act); and

4) maintained in a leak-free condition. (Section 1-75(c)(6) of the Act)

d) Stationary fueling tanks shall meet the requirements of this subsection (d).

1) Stationary fueling tanks shall have secondary containment in accordance with subsection (b) (Section 1-70(c)(2) of the Act);

2) Stationary fueling tanks shall be subject to the setback requirements of

Section 245.400 (Section 1-70(c)(2) of the Act);

3) Stationary fueling tank filling operations shall be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck (Section 1-70(c)(3) of the Act); and

4) Troughs, drip pads, or drip pans are required beneath the fill port of a stationary fueling tank during filling operations if the fill port is not within the secondary containment required by subsection (b) (Section 1-70(c)(4) of the Act).

e) Fresh water may be stored in tanks or pits at the election of the permittee (Section 1-75(c)(3) of the Act).

f) Any tank, structure, measure or device intended or used for storage of hydraulic fracturing fluid, hydraulic fracturing flowback, or produced water, unless demonstrated to be outside the regulatory floodplain, shall be considered a construction subject to 17 Ill. Adm. Code 3706.240 and 3706.630 and constructed to the standards set forth in 17 Ill. Adm. 3706.530(b) or (c), as applicable. No above-ground tanks or secondary containment structure, measure or device

Section 245.835 Mechanical Integrity Monitoring

a) During high volume horizontal hydraulic fracturing operations, all sealed annulus pressures, the injection pressure, and the rate of injection shall be continuously monitored and recorded. The records of the monitoring shall be maintained by the permittee in the well file and shall be provided to the Department upon request at any time during the period up to and including 5 years after the well is permanently plugged or abandoned. (Section 1-75(b)(4) of the Act)

b) During high volume horizontal hydraulic fracturing operations:

1) The pressure test values established for the internal mechanical integrities of the cemented casings pursuant to Section 245.540 and of the hydraulic fracturing string pursuant to Section 245.805 shall not be exceeded. If any of these pressures decline more than 5% or if there are other indications of a leak, including but not limited to an increase in pressure in the annulus, exceeding the minimum internal yield in the casing string, or a visible leak at the surface, corrective action shall be taken before conducting further high volume horizontal hydraulic fracturing operations. (Section 1-70(d)(16) of the Act)

2) The pressure exerted on treating equipment, including valves (includes hydraulic fracturing string relief valve; see Section 245.805(b) of this Part and Section 1-70(d)(17) of the Act), lines, manifolds, hydraulic fracturing head or tree, casing and hydraulic fracturing string, if used, and any other wellhead component or connection, must not exceed 95% of the working pressure rating of the weakest component (Section 1-75(b)(2) and (b)(3) of the Act).

3) The relief valve installed pursuant to Section 245.560(o) should be set so that the pressure exerted on the casing does not exceed the mechanical integrity test pressure of the casing established pursuant to Section 245.240.

4) The actual hydraulic fracturing treatment pressure during HVHHF operations must not, at any time, exceed the mechanical integrity test pressures of the casings established pursuant to Section 245.540 (Section 1-70(d)(18) of the Act).

c) High volume horizontal hydraulic fracturing operations must be immediately suspended if the permittee or Department inspector determines that any anomalous pressure or flow condition or any other anticipated pressure or flow condition is occurring in a way that indicates the mechanical integrity of the well has been compromised and continued operations pose a risk to public health, public safety, property, wildlife, aquatic life or the environment. Remedial action shall be immediately undertaken. (Section 1-75(b)(5) of the Act)

d) The permittee shall notify the Department inspector and the Department's District Office by phone and electronic mail within 1 hour after suspending operations for any matters relating to the mechanical integrity of the well or risk to the environment. (Section 1-75(b)(5) of the Act)

e) Operations shall not resume until the appropriate pressure tests referenced in Sections 245.805 and 245.810 have been successfully repeated.

Section 245.840 Hydraulic Fracturing Fluid and Flowback Confinement

a) Hydraulic fracturing fluid shall be confined to the targeted formation designated in the permit.

b) If the hydraulic fracturing fluid or hydraulic fracturing flowback migrate into a fresh water zone or to the surface from the well in question or from other wells, the permittee shall immediately notify the Department and the county and certified local public health department (if any) and shut in the well until remedial action that prevents the fluid migration is completed. The permittee shall obtain the approval of the Department prior to resuming operations. (Section 1-75(d) of the Act)

c) Permittee shall be responsible for damages caused by the migration of hydraulic fracturing fluid or hydraulic fracturing flowback outside the targeted formation.

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Section 245.845 Management of Gas and Produced Hydrocarbons During Flowback

For wells regulated by this Part, permittees shall be responsible for managing natural gas and hydrocarbon fluids produced during the flowback period to ensure no direct release to the atmosphere or environment as follows:

a) Except for wells covered by subsection (f), recovered hydrocarbon fluids shall be:

1) Routed to one or more storage vessels; or

2) Injected into a permitted Class II UIC well as described in Section 245.300(c)(7); or

3) Used for another lawful and useful purpose that a purchased fuel or raw material would serve, with no direct release to the environment.

b) Except for wells covered by subsection (e), recovered natural gas shall be:

1) Routed into a flow line or collection system; or

2) Injected into a permitted Class II UIC well as described in Section 245.300(c)(7); or

3) Used as an on-site fuel source; or

4) Used for another lawful and useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. (Section 1- 75(e)(2) of the Act)

c) If it is technically infeasible or economically unreasonable to minimize emissions associated with the venting of hydrocarbon fluids and natural gas during the flowback period using the methods specified in subsections (a) and (b), the Department, in consultation with the Agency as the Department deems appropriate, shall require the permittee to capture and direct the emissions to a completion combustion device, except:

1) When conditions may result in a fire hazard or explosion; or

2) Where high heat emissions from a completion combustion device may negatively impact waterways.

d) In order to establish technical infeasibility under subsection (c), the permittee must demonstrate to the Department's satisfaction that the technology listed in subsections (a) and (b) does not exist, cannot be installed at the well site, will not achieve the result intended, or is otherwise unavailable or ineffective. The permittee claiming economic unreasonableness shall provide the Department with the following:

1) The method the applicant used to determine it is economically unreasonable to implement the methods specified in subsection (a) or (b);

2) Applicant's experience in implementing the methods specified in subsection (a) or (b);

3) Estimated costs of implementing the methods specified in subsection (a) or (b), and sources for those estimates;

4) Anticipated rates (by day) and amounts (total for well) of fluids and/or gas to be directed to the completion combustion device; and

5) Any other information requested by the Department or that documents the economic unreasonableness claimed.

e) Completion combustion devices must be equipped with an auto-igniter and a reliable continuous ignition source over the duration of the flowback period. (Section 1-75(e)(3) of the Act)

f) For each wildcat well, delineation well, or low pressure well, permittees shall be responsible for minimizing the emissions associated with venting of hydrocarbon fluids and natural gas during the flowback period by capturing and directing the emissions to a completion combustion device during the flowback period, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact waterways. Completion combustion devices shall be equipped with a reliable continuous ignition source over the duration of the flowback period. (Section 1- 75(e)(8) of the Act)

Section 245.850 Hydraulic Fracturing Fluid and Hydraulic Fracturing Flowback Storage, Disposal or Recycling, Transportation and Reporting Requirements

The permittee shall notify the Department of the date when HVHHF operations are completed and shall dispose of or recycle hydraulic fracturing fluids and hydraulic fracturing flowback pursuant to the requirements of this Section.

a) Completion of HVHHF operations occurs when the flowback period begins after the last stage of HVHHF operations. The permittee shall notify the Department's District Office by phone and electronic mail within 24 hours after HVHHF operations are completed.

b) Hydraulic fracturing fluids and hydraulic fracturing flowback must be removed from the well site within 60 days after completion of high volume horizontal fracturing operations, except as provided in subsection (c) (Section 1-75(c)(5) of the Act).

c) Any excess hydraulic fracturing flowback captured for temporary storage in a reserve pit as provided in Section 245.825 must be either removed from the well site or transferred to storage in above-ground tanks for later disposal or recycling within 7 days after the fluid is first deposited into the reserve pit (Section 1- 75(c)(5) of the Act). Excess hydraulic fracturing flowback cannot be removed from the well site until the hydraulic fracturing flowback is tested and the analytical results are provided pursuant to subsection (d).

d) Testing of hydraulic fracturing flowback shall be completed as follows:

1) Hydraulic fracturing flowback must be tested for the presence of volatile organic chemicals, semi-volatile organic chemicals, inorganic chemicals, heavy metals, and naturally occurring radioactive material before removal from the well site, including specifically:

A) pH;

B) total dissolved solids, dissolved methane, dissolved propane, dissolved ethane, alkalinity and specific conductance;

C) chloride, sulfate, arsenic, barium, calcium, chromium, iron, magnesium, selenium, cadmium, lead, manganese, mercury and silver;

D) BTEX; and

E) gross alpha and beta particles to determine the presence of any naturally occurring radioactive materials.

2) Testing shall be completed on a composited sample of the hydraulic fracturing flowback.

3) Testing shall occur once per well site at an Agency-accredited or -certified independent laboratory. When no laboratory has been accredited or certified by the Agency to analyze a particular substance requested in this subsection (d), results will be considered only if they have been analyzed by a laboratory accredited or certified by another State agency or an agency of the federal government, if the standards used for the accreditation or certification of that laboratory are substantially equivalent to the accreditation standard under Section 4(o) of the Illinois Environmental Protection Act [415 ILCS 5].

4) The analytical results shall be filed with the Department and the Agency, and provided to the liquid oilfield waste transportation and disposal operators at or before the time of pickup. (Section 1-75(c)(7) of the Act)

e) Before plugging and site restoration required by Section 245.1030, the ground adjacent to the storage tanks and any hydraulic fracturing flowback reserve pit must be measured for radioactivity (Section 1-75(c)(7) of the Act).

f) Surface discharge of hydraulic fracturing fluids or hydraulic fracturing flowback onto the ground or into any surface water or water drainage way at the well site or any other location is prohibited (Sections 1-75(c)(9) and 1-25(c) of the Act).

g) Except for recycling allowed by subsection (i), hydraulic fracturing flowback may only be disposed of by injection into a Class II injection disposal well that is below interface between fresh water and naturally occurring Class IV groundwater (Sections 1-75(c)(8) and 1-25(c) of the Act). The Class II injection disposal well must be equipped with an electronic flowmeter and approved by the Department.

h) Fluid transfer operations from tanks to tanker trucks for transportation offsite must be supervised at the truck and at the tank if the tank is not visible to the truck operator from the truck. During transfer operations, all interconnecting piping must be supervised if not visible to transfer personnel at the truck and tank. (Section 1-75(c)(6) of the Act)

i) Hydraulic fracturing flowback may be treated and recycled for use in hydraulic fracturing fluid for high volume horizontal hydraulic fracturing operations. (Section 1-75(c)(8) of the Act)

j) Transport of all hydraulic fracturing fluids and hydraulic fracturing flowback by vehicle for disposal or recycling must be undertaken by a liquid oilfield waste hauler permitted by the Department under Section 8c of the Illinois Oil and Gas Act. The liquid oilfield waste hauler transporting hydraulic fracturing fluids or hydraulic fracturing flowback under this Part shall comply with all laws, rules, and regulations concerning liquid oilfield waste. (Section 1-75(c)(10) of the Act)

k) A fluid handling report on the transportation and disposal or recycling of the hydraulic fracturing fluids and hydraulic fracturing flowback shall be prepared by the permittee on a form prescribed by the Department and included in the well file.

1) Each report must include:

A) the amount of hydraulic fracturing fluids or hydraulic fracturing flowback transported;

B) identification of the company that transported the hydraulic fracturing fluids or hydraulic fracturing flowback;

C) the date the hydraulic fracturing fluids or hydraulic fracturing flowback were picked up from the well site (see Section 1- 75(c)(14) of the Act);

D) the destination of the hydraulic fracturing fluids or hydraulic fracturing flowback, including the name, address and type of facility accepting the hydraulic fracturing fluids or hydraulic fracturing flowback;

E) the method of disposal (Section 1-75(c)(14) of the Act) or recycling; and

F) a copy of the analytical results of the testing required pursuant to subsection (d).

2) The permittee shall prepare 4 copies of each fluid handling report for distribution as follows:

A) one copy for the permittee's records;

B) two copies for the liquid oilfield waste hauler upon pick-up of the liquids as follows:

i) one copy for the waste hauler's records; and

ii) one copy to be provided to the permittee of the Class II UIC well, to the operator of the storage location where the liquids will be disposed of, or to the operator of the storage location where liquids will be recycled; and

C) one copy for the Department. A set of all fluid handling reports shall be submitted to the Department within 90 days after the completion of all HVHHF operations.

3) All copies of the fluid handling reports shall be retained for at least 5 years.

Section 245.855 Spills and Remediation

a) Any release of hydraulic fracturing fluid, hydraulic fracturing additive, hydraulic fracturing flowback, or produced water, used or generated during or after high volume horizontal hydraulic fracturing operation, shall be immediately cleaned up and remediated pursuant to requirements of the Illinois Oil and Gas Act and the administrative rules promulgated under the Act.

b) Any release of hydraulic fracturing fluid or hydraulic fracturing flowback in excess of one barrel, shall be reported to the Department.

c) Any release of produced water in excess of 5 barrels shall be cleaned up, remediated, and reported pursuant to requirements of the Illinois Oil and Gas Act and the administrative rules promulgated under that Act.

d) Any release of a hydraulic fracturing additive shall be reported to IEMA in accordance with the appropriate reportable quantity thresholds established under the federal Emergency Planning and Community Right-to-Know Act as published at 40 CFR 355, 370, and 372, the federal Comprehensive Environmental Response, Compensation, and Liability Act as published in 40 CFR 302, and Section 112(r) of the Federal Clean Air Act as published at 40 CFR 68. (Section 1-75(c)(12) of the Act)

Section 245.860 High Volume Horizontal Hydraulic Fracturing Operations Completion Report

a) Within 60 calendar days after the conclusion of high volume horizontal hydraulic fracturing operations, the permittee shall file a high volume horizontal hydraulic fracturing operations completion report with the Department in hard copy and electronic format (PDF).

b) A copy of each completion report submitted to the Department shall be provided by the Department to the Illinois State Geological Survey in electronic format.

c) Completion reports shall be made available on the Department's website no later than 30 days after receipt by the Department. (Section 1-75(f) of the Act)

d) The high volume horizontal hydraulic fracturing operations completion report shall contain the following information (Section 1-75(f) of the Act):

1) the permittee's name as listed in the permit application (Section 1-75(f)(1) of the Act);

2) the dates of the high volume horizontal hydraulic fracturing operations

(Section 1-75(f)(2) of the Act);

3) the county where the well is located (Section 1-75(f)(3) of the Act);

4) the well name and Department reference number (Section 1-75(f)(4) of the Act);

5) the total water volume used in each stage and the total used in the high volume horizontal hydraulic fracturing operations of the well, and the type and total volume of the base fluid used if something other than water (Section 1-75(f)(5) of the Act);

6) each source from which the water used in the high volume horizontal hydraulic fracturing operations was drawn, and the specific location of each source, including, but not limited to, the name of the county and latitude and longitude coordinates (Section 1-75(f)(6) of the Act);

7) the quantity of hydraulic fracturing flowback recovered from the well and the time period for flowback recovery (Section 1-75(f)(7) of the Act);

8) a description of how hydraulic fracturing flowback recovered from the well was disposed or recycled (Section 1-75(f)(8) of the Act);

9) a chemical disclosure report identifying each chemical and proppant used in hydraulic fracturing fluid for each stage of the high volume horizontal hydraulic fracturing operations including the following (Section 1- 75(f)(9) of the Act):

A) the total volume of water used in the high volume horizontal hydraulic fracturing treatment of the well or the type and total volume of the base fluid used in the high volume horizontal hydraulic fracturing treatment, if something other than water (Section 1-75(f)(9)(A) of the Act);

B) each hydraulic fracturing additive used in the hydraulic fracturing fluid, including the trade name, vendor, a brief descriptor of the intended use or function of each hydraulic fracturing additive, and the Material Safety Data Sheet (MSDS), if applicable (Section 1- 75(f)(9)(B) of the Act);

C) each chemical intentionally added to the base fluid, including, for each chemical, the Chemical Abstracts Service number, if applicable (Section 1-75(f)(9)(C) of the Act); and

D) the actual concentration in the base fluid, in percent by mass, of each chemical intentionally added to the base fluid (Section 1- 75(f)(9)(D) of the Act);

10) a copy of the hydraulic fracturing string pressure test conducted pursuant to Section 245.805(e), if applicable;

11) all pressures recorded during the high volume horizontal hydraulic fracturing operations in accordance with Section 245.835 (Section 1- 75(f)(10) of the Act);

12) plans for how produced water will be disposed of or recycled as required by Section 245.940 (see Section 1-75(c)(8) of the Act). If produced water is to be disposed of, the names and locations of Class II injection wells to be used. All Class II injection wells to be used for disposal of produced water must be shown to be in compliance with 62 Ill. Adm. Code 240.360 at the time of the issuance of the high volume horizontal hydraulic fracturing permit; and

13) any other reasonable or pertinent information related to the conduct of the high volume horizontal hydraulic fracturing operations the Department may request or require (Section 1-75(f)(11) of the Act).

e) The HVHHF operations completion report must be approved and signed and certified by a licensed professional engineer, licensed profession geologist or the permittee.

Section 245.870 Use of Diesel in High Volume Horizontal Hydraulic Fracturing Operations is Prohibited

It is unlawful to perform any high volume horizontal hydraulic fracturing operations by knowingly or recklessly injecting diesel (Section 1-25(d) of the Act).

SUBPART I: HIGH VOLUME HORIZONTAL HYDRAULIC FRACTURING PRODUCTION

Section 245.900 Managing Natural Gas and Hydrocarbon Fluids During Production

For wells regulated by this Part, permittees shall be responsible for minimizing the emissions associated with venting of hydrocarbon fluids and natural gas during the production phase to safely maximize resource recovery and minimize releases to the environment (Section 1-75(e)(4) of the Act).

a) Except for wells covered by subsection (i), sand traps, surge vessels, separators, and tanks must be employed as soon as practicable during cleanout operations to safely maximize resource recovery and minimize releases to the environment. (Section 1-75(e)(4)(B) of the Act)

b) Except for wells covered by subsection (i), recovered hydrocarbon fluids must be routed into storage vessels. (Section 1-75(e)(4)(A) of the Act)

c) Except for wells covered by subsection (i), recovered natural gas must be:

1) routed into a gas gathering line or collection system, or to a generator for onsite energy generation;

2) provided to the surface landowner of the well site for use for heat or energy generation; or

3) used for a lawful and useful purpose other than venting or flaring. (Section 1-75(e)(4)(A))

d) If the permittee establishes that it is technically infeasible or economically unreasonable to minimize emissions associated with the venting of hydrocarbon fluids and natural gas during production using the methods specified in subsections (b) and (c), the Department, in consultation with the Agency as the Department deems appropriate, shall require the permittee to capture and direct any natural gas produced during the production phase to a flare.

e) In order to establish technical infeasibility under subsection (d), the permittee must demonstrate to the Department's satisfaction, for each well site on an annual basis, that taking the actions listed in subsections (b) and (c) are not cost effective based on a well site-specific analysis, and that the technology listed in subsections (b) and (c) does not exist, cannot be installed at the well site, will not achieve the result intended, or is otherwise unavailable or ineffective. The permittee claiming economic unreasonableness shall provide the Department with the following:

1) The method the applicant used to determine it is economically unreasonable to implement the methods specified in subsection (b) or (c);

2) Applicant's experience in implementing the methods specified in subsection (b) or (c);

3) Estimated costs of implementing the methods specified in subsection (b) or (c) and sources for those estimates;

4) Anticipated rates (by day) and amounts (total for well) of fluids and/or gas to be directed to the flare; and

5) Any other information requested by the Department or that documents the economic unreasonableness claimed.

f) Any flare used pursuant to this Section shall be equipped with an auto-igniter and a reliable continuous ignition source over the duration of production. The manufacturer's specifications for all flares must be provided to the Department before operation of the flare begins, and the Department shall post the specifications to its website.

g) Permittees that use a flare during the production phase for operations other than emergency conditions shall visually inspect or monitor the flare on a regular basis to insure it is operating properly. The permittee shall file an updated well site- specific analysis annually with the

Department on a form prescribed by the Department in consultation with the Agency. The analysis shall:

1) be due one year from the date of the previous submission;

2) report the dates and duration of any period during which the flare is not operating properly; and

3) detail whether any changes have occurred that alter the technical infeasibility or economic unreasonableness of the permittee to reduce emissions in accordance with subsections (b) and (c). (Section 1-75(e)(5) of the Act)

h) On or after July 1, 2015, all flares used under this Section shall:

1) operate with a combustion efficiency of at least 98% and in accordance with 40 CFR 60.18;

2) be certified by the manufacturer of the device; and

3) be maintained and operated in accordance with manufacturer specifications. (Section 1-75(e)(9) of the Act)

i) For each wildcat well, delineation well, or low pressure well, permittees shall be responsible for minimizing the emissions associated with venting of hydrocarbon fluids and natural gas during the production phase by capturing and directing the emissions to a flare during the production phase, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a flare may negatively impact waterways. Flares shall be used during the production phase. (Section 1-75(e)(8) of the Act)

Section 245.910 Uncontrolled Emissions from Storage Tanks Containing Natural Gas and Hydrocarbon Fluids

a) In addition to the requirements of Section 245.900, uncontrolled emissions exceeding 6 tons per year from storage tanks containing natural gas or hydrocarbon fluids shall be recovered and routed to a flare that is designed in accordance with 40 CFR 60.18 and is certified by the manufacturer of the device. Permittees shall calculate whether uncontrolled emissions from storage tanks exceed 6 tons per year by using a generally accepted model or calculation methodology based on the maximum average daily throughput determined for a 30 day period of production prior to the applicable emission determination deadline, pursuant to 40 CFR 60.5365(e).

b) The permittee shall maintain and operate the flare in accordance with the manufacturer's specifications.

c) Any flare used under this Section must be equipped with an auto-igniter and a reliable continuous ignition source over the duration of production pursuant to the requirements of Section 245.900(h). (Section 1-75(e)(6) of the Act) The manufacturer's specifications for all flares must be provided to the Department before operation of the flare begins, and the Department shall post the specifications to its website.

Section 245.920 Flaring Waiver

For wells regulated by this Part:

a) The Department, in consultation with the Agency as the Department deems appropriate, may approve an exemption request made in writing that waives the flaring requirements of Sections 245.900 and 245.910 only if the permittee demonstrates to the Department's satisfaction that the use of the flare will pose a significant risk of injury or property damage and that alternative methods of collection will not threaten harm to public health, public safety, property, wildlife, aquatic life or the environment (Section 1-75(e)(7) of the Act).

b) In determining whether to approve a waiver, the Department, in consultation with the Agency as the Department deems appropriate, shall consider the quantity of casinghead gas produced, the topographical and climatological features at the well site, and the proximity of agricultural structures, crops, inhabited structures, public buildings, and public roads and railways (Section 1-75(e)(7) of the Act).

c) The Department, in consultation with the Agency as the Department deems appropriate, shall provide the permittee with a written decision.

Section 245.930 Annual Flaring Reports

Pursuant to Sections 245.900 and 245.910, permittees shall record the amount of gas flared or vented from each high volume horizontal hydraulic fracturing well or storage tank on at least a weekly basis (Section 1-75(e)(11) of the Act). Every 12 months from the date of permit issuance under this Part, permittees shall report the total amount of gas flared or vented from each well during the previous 12 months, by week, to the Department. The Department will post the reports on the Department's website.

Section 245.940 Produced Water Disposal or Recycling, Transportation and Reporting Requirements

The permittee shall dispose of or recycle produced water in accordance with the requirements of this Section:

a) Surface discharge of produced water onto the ground or into any surface water or water drainage way is prohibited (Sections 1-75(c)(9) and 1-25(c) of the Act).

b) Except for recycling allowed under subsection (d), produced water may only be disposed of by injection into a Class II injection well that is below interface between fresh water and naturally occurring Class IV groundwater (Sections 1- 75(c)(8) and 1-25(c) of the Act). Unless used for enhanced oil recovery, the Class II injection well must be equipped with an electronic flowmeter and approved by the Department.

c) Produced water transfer operations from tanks to tanker trucks for transportation offsite must be supervised at the truck and at the tank if the tank is not visible to the truck operator from the truck. During transfer operations, all interconnecting piping must be supervised if not visible to transfer personnel at the truck and tank. (Section 1-75(c)(6) of the Act)

d) Produced water may be treated and recycled for use in hydraulic fracturing fluid for high volume horizontal hydraulic fracturing operations (Section 1-75(c)(8) of the Act).

e) Transport of produced water by vehicle for disposal or recycling must be undertaken by a liquid oilfield waste hauler permitted by the Department under Section 8c of the Illinois Oil and Gas Act. The liquid oilfield waste hauler transporting produced water under this Part shall comply with all laws, rules, and regulations concerning liquid oilfield waste. (Section 1-75(c)(10) of the Act)

f) Permittees must submit an annual produced water report to the Department detailing the management of any produced water associated with the permitted well.

1) The produced water report shall be due to the Department no later than April 30 of each year and shall provide information on the operator's management of any produced water for the prior calendar year and the anticipated management for the next calendar year; and

2) The produced water report shall contain information relative to the amount of produced water from the well, the method by which the produced water was transported and disposed of or recycled, the destination where the produced water was disposed of (Section 1- 75(c)(15) of the Act) or recycled.

SUBPART J: PLUGGING AND RESTORATION

Section 245.1000 Plugging and Restoration Requirements

a) The permittee shall perform and complete plugging of the well and restoration of the well site in accordance with the Illinois Oil and Gas Act and any and all rules adopted under that Act (62

Ill. Adm. Code 240.Subpart K). The permittee shall bear all costs related to plugging of the well and reclamation of the well site.

b) If the permittee fails to plug the well in accordance with this Section, the owner of the well shall be responsible for complying with this Section. (Section 1-95(a) of the Act)

c) Special Plugging Requirement

If the permittee stimulates the geologic formation in accordance with the permit using a high volume horizontal hydraulic fracturing process, then once commercial production ceases from the well and it is time to plug the well, in addition to all the other requirements, the permittee shall initiate the plugging process using a circulation method starting at the top of the geologic formation stimulated installing a cement plug at least 100 feet above the top of the geologic formation.

d) Upon completion of the requirements of this Subpart J, the Department will release the permit in accordance with Section 245.350.

Section 245.1010 Plugging Previously Abandoned Unplugged or Insufficiently Plugged Wells

a) The permittee shall plug any abandoned unplugged, or insufficiently plugged, well bores within 750 feet of any part of the horizontal well bore that penetrated within 400 vertical feet of the geologic formation that will be stimulated as part of the permittee's proposed high volume horizontal hydraulic fracturing operations (Section 1-95 of the Act). In determining whether a well has been sufficiently plugged, the Department will consider, but is not limited to, well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs and plugging records. The permittee shall complete this plugging before the permittee conducts any HVHHF operations.

b) This pre-HVHHF operations plugging obligation shall be performed in accordance with 62 Ill. Adm. Code 240.1110.

1) If the permittee does not have authority to plug an abandoned well within the Plugging and Restoration Fund Program, the Department will give the permittee authority to enter upon the land, plug the well, and restore the well site consistent with 62 Ill. Adm. Code 240.1610(e).

2) If the permittee does not have authority to plug an abandoned well that is not within the Plugging and Restoration Fund Program, either:

A) the Department will initiate abandoned well proceedings pursuant to Section 19.1 of the Illinois Oil and Gas Act and 62 Ill. Adm. Code 240.1610, in order to grant the permittee authority to plug the abandoned well; or

B) the permittee will work with the landowner and the person responsible for the abandoned well to arrange for plugging and restoration.

c) If the permittee is unable to locate an abandoned unplugged well or insufficiently plugged well identified by the Department for plugging before HVHHF operations begin, the permittee may receive a waiver of the plugging requirement from the Department after demonstrating a diligent effort to locate the abandoned unplugged well or insufficiently plugged well in the field.

d) Before proceeding with any HVHHF operations, the permittee shall receive written approval from the Department that all wells under the permit within 750 feet of any part of the horizontal well bore that appear to penetrate within 400 vertical feet of the formation that the permittee intends to stimulate have been plugged, or that the plugging requirements have been met.

e) If, during or after performing HVHHF operations, there is any evidence of fluids leaking at the surface from abandoned wells, unpermitted wells, or previously plugged wells within 750 feet of any part of the horizontal well bore:

1) the permittee shall immediately stop hydraulic fracturing operations, notify the Department, and shut in the well;

2) the permittee shall plug those wells and restore the well sites in accordance with 62 Ill. Adm. Code 240.870, 240.875 and 240.1110; and

3) the permittee shall obtain the approval of the Department prior to resuming operations.

f) If, during or after performing HVHHF operations, there is any evidence of damage from the permittee's HVHHF operations to a producing well within 750 feet of any part of the horizontal well bore, the permittee shall be responsible for all repairs to the well construction or the costs of plugging the damaged well.

9.1.8 Kansas

Regulatory Authority: Kansas Oil and Gas Conservation Division

Reference Source: General Rules and Regulations for the Conservation of Crude Oil and Natural Gas

CHEMICAL DISCLOSURE OF HYDRAULIC FRACTURING TREATMENT

82-3-1401 HYDRAULIC FRACTURING TREATMENT; CHEMICAL DISCLOSURE.

(a) Applicability. This regulation shall apply to each hydraulic fracturing treatment that uses more than 350,000 gallons of base fluid.

(b) Operator disclosures. Unless the operator submits all information to the chemical disclosure registry under subsection (f), the operator shall submit to the commission a list of each hydraulic fracturing treatment as part of the completion report required by K.A.R. 82-3-130. The list shall include the following information, as a percentage by mass of the total amount of hydraulic fracturing fluid:

(1) The base fluid used, including its total volume;

(2) each proppant; and

(3) each chemical constituent at its maximum concentration in the hydraulic fracturing fluid and its CAS number.

(c) Disclosures not required. No operator shall be required to disclose any chemical constituent that meets any of the following conditions:

(1) Is the incidental result of a chemical reaction or chemical process;

(2) is a component of a naturally occurring material and becomes part of the hydraulic fracturing fluid during the hydraulic fracturing treatment; or

(3) is a trade secret.

(d) Trade secrets. Each operator reporting that a chemical constituent is a trade secret shall indicate to the commission that disclosure of the chemical constituent is being withheld pursuant to a trade secret claimed by the operator, manufacturer, supplier, or Service Company. The operator shall provide the name of the chemical family or a similar descriptor and the name, authorized representative, mailing address, and phone number of the party claiming the trade secret.

(e) Inaccurate or incomplete information. No operator shall be responsible for inaccurate or incomplete information provided by a manufacturer, supplier, or service company.

(f) Alternate disclosure mechanism. In lieu of complying with subsection (b), the operator may submit the information required by subsection (b) to the chemical disclosure registry. The operator shall submit verification of prior submission to the chemical disclosure registry as part of the completion report required by K.A.R. 82-3-130. Each submission to the chemical disclosure registry shall also include the following information:

(1) The operator's name;

(2) the date on which the hydraulic fracturing treatment began;

(3) the county in which the treated well is located;

(4) the American petroleum institute number for the well;

(5) the well name and number;

(6) the global positioning system (GPS) location of the wellhead; and

(7) the true vertical depth of the well.

82-3-1402 HYDRAULIC FRACTURING TREATMENT; DISCLOSURE OF TRADE SECRETS.

(a) Director.

(1) The manufacturer, supplier, Service Company, or operator shall provide the specific identity of a chemical constituent reported to be a trade secret to the director under the following circumstances:

(A) Within two business days after receipt of a letter from the director stating that the information is necessary to investigate a spill or contamination of fresh and usable water relating to a hydraulic fracturing treatment; or

(B) immediately following notice from the director that an emergency requiring disclosure exists.

(2) The director may authorize disclosure of a trade secret disclosed under paragraph (a)(1) to any of the following persons:

(A) Any commissioner or commission staff member;

(B) the secretary or any staff member of the department of health and environment; or

(C) any relevant public health officer or emergency manager.

(b) Health professionals.

(1) A manufacturer, supplier, service company, or operator shall provide the specific identity of a chemical constituent reported to be a trade secret to any health professional who meets one of the following requirements:

(A) Provides a written statement of need and signs a confidentiality agreement on a form provided by the commission; or

(B) determines that the information is reasonably necessary for emergency treatment, verbally agrees to confidentiality, and provides a written statement of need and signed confidentiality agreement as soon as circumstances permit.

(2) Each statement of need shall state that the health professional has reasonable basis to believe that the information will assist in diagnosis or treatment of a specific individual who could have been exposed to the chemical constituents.

(3) Each confidentiality agreement shall state that the health professional will not disclose or use the information for any reason other than those reasons asserted in the statement of need.

(c) Continued confidentiality. A trade secret disclosed pursuant to this regulation shall not be further disclosed except as authorized by this regulation, K.S.A. 66-1220a and amendments thereto, or K.A.R. 82-1-221a.

9.1.9 Kentucky

Regulatory Authority: Kentucky Department of Natural Resources, Division of Oil and Gas

Reference Source: Commonwealth of Kentucky Oil and Gas Well Operations Manual

Hydraulic Fracturing (Use of Diesel Fuel), U.S. Environmental Protection Agency (USEPA)

The use of diesel fuel as an additive in fracturing fluids shall be regulated under the Underground Injection Control (UIC) program pursuant to the Safe Water Drinking Act. Any well owner/operator that contracts with a well service company to use diesel fuel as a fracturing fluid or an additive must first obtain a Class II permit from USEPA-Region VI prior to performing the fracturing treatment. If the Division of Oil and Gas receives primacy of the UIC-Class II program, the well operator must comply with any provisions as it relates to stimulation using diesel fuel as directed by USEPA.

Disposal of Completion Fluids, Division of Waste Management

Completion fluids fall under the definition of solid non-hazardous waste. Temporary storage of these fluids is regulated as a solid waste permit-by-rule. Permit-by-rule sites do not need to submit any paperwork to the Division, but do need to comply with the environmental performance standards. Disposal of such waste is not covered by a permit-by-rule, and the applicable regulations depend on the disposal method to be employed. In order to dispose of the waste at the site by applying it to the land, a permit shall be obtained. The waste can be hauled off-site and disposed of in a permitted solid waste landfill, as long as it is allowed under the permit for that landfill.

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9.1.10 Louisiana

Regulatory Authority: Louisiana Department of Natural Resources

Reference Source: Title 43. Natural Resources. Part XIX. Office of Conservation—General Operations. Subpart 1. Statewide Order No. 29-B

§118. Hydraulic Fracture Stimulation Operations

A. The provisions of this Section shall apply to all new wells for which an initial drilling permit is issued on or after the effective date of this Section that are stimulated by the application of fluids, which contain proppant such as sand or man-made inert material, with force and/or pressure in order to create artificial fractures in the formation for the purpose of improving the capacity to produce hydrocarbons. The provisions of this Section shall not apply to operations conducted solely for the purposes of sand control or reduction of near wellbore damage.

B. An application for hydraulic fracture stimulation shall be made to the district office on Form DM-4R in accordance with the provisions of LAC 43:XIX.105 and a proper work permit shall be received from the district manager prior to beginning operations.

C. No later than 20 days following completion of the hydraulic fracture stimulation operation, the operator shall, for purposes of disclosure, report the following information on or with the well history and work resume report (Form Louisiana Administrative Code June 2015 8 Title 43, Part XIX

WH) in accordance with the requirements of LAC 43:XIX.105:

a. the types and volumes of the Hydraulic Fracturing Fluid (base fluid) used during the Hydraulic Fracture Stimulation Operation expressed in gallons; and

b. a list of all additives used during the Hydraulic Fracture Stimulation Operation, such as acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, scale inhibitor, proppant and surfactant; and

c. for each additive type, listed under Subparagraph b above, the specific trade name and suppliers of all the additives utilized during the Hydraulic Fracture Stimulation Operation; and

d. a list of chemical ingredients contained in the hydraulic fracturing fluid that are subject to the requirements of 29 CFR Section 1910.1200(g)(2) and their associated CAS numbers;

e. the maximum ingredient concentration within the additive expressed as a percent by mass for each chemical ingredient listed under Subparagraph d;

f. the maximum concentration of each chemical ingredient listed under Subparagraph d, expressed as a percent by mass of the total volume of hydraulic fracturing fluid used.

2.a. Notwithstanding Subparagraph d, if the specific identity of a chemical ingredient and the chemical ingredient's associated CAS number are claimed to be trade secret, or have been finally determined to be entitled to protection as a trade secret under the criteria cited in 42 USC 11042(a)(2), and specifically enumerated at 42 USC 11042(b), the entity entitled to make such a claim may withhold the specific identity of the chemical ingredient and the chemical ingredients associated CAS number from the list required by Subparagraph d. If the entity entitled to make such a claim elects to withhold that information, the report must:

i. disclose the chemical family associated with the ingredient; and

ii. include a statement that a claim of trade secret protection has been made by the entity entitled to make such a claim.

iii. the contact information of the entity claiming trade secret protection.

b. An operator will not be responsible for reporting information that is not provided to them due to a claim of trade secret protection by the entity entitled to make such a claim.

3. Nothing in Paragraph 2 above shall authorize any person to withhold information which is required by state or federal law to be provided to a health care professional, a doctor, or a nurse.

4. The operator may furnish a statement signifying that the required information has been submitted to the Ground Water Protection Council Hydraulic Fracturing Chemical Registry or any other similar registry, provided all information is accessible to the public free of charge, to satisfy some or all of the information requirements of this Subsection.

5. Any information provided to the department pursuant to the provisions of this Section shall be subject to examination and reproduction as provided by the Public Records Law, R.S. 44:1 et seq., or any other applicable law.

§313. Pit Closure Techniques and Onsite Disposal of E and P Waste

J. Temporary Use of E and P Waste (Produced Water, Rainwater, Drilling, Workover, Completion and Stimulation Fluids) for Hydraulic Fracture

1. Produced water, rainwater, drilling, workover, completion and stimulation fluids generated at a wellsite (originating wellsite) that are classified as E and P waste may be transported offsite for use in hydraulic fracture stimulation operations at another wellsite (receiving wellsite) provided that the following conditions are met.

a. The originating wellsite and the receiving wellsite must have the same operator of record.

b. All residual waste generated in the treatment or processing of E and P waste prior to its use in hydraulic fracture stimulation operations must be properly disposed of in accordance with the following:

i. All residual waste generated as a result of treatment or processing conducted at the originating wellsite must be either disposed of onsite at the originating wellsite in accordance with all the requirements of LAC 43:XIX.311 and 313, except and not including Subsection 313.J, or offsite in accordance with the requirements of LAC 43:XIX.Chapter 5.

ii. All residual waste generated as a result of treatment or processing conducted at the receiving wellsite must be disposed of offsite in accordance with the requirements of LAC 43:XIX.Chapter 5.

c. The types and volumes of E and P Waste generated for temporary use along with the well name and well serial number of the receiving wellsite must be reported on Form ENG-16 (Oilfield Waste Disposition) for the originating well and/or Form UIC-28 (Exploration and Production Waste Shipping Control Ticket) and/or other appropriate forms specified by the commissioner depending on the waste types involved.

d. An affidavit must be provided by the operator which attests that the operator has authority to store and use E and P waste from an offsite location at the receiving wellsite. The affidavit must be in a format acceptable to the Commissioner and attached to Form ENG-16 (Oilfield Waste Disposition) for the originating well and/or Form UIC-28 (Exploration and Production Waste Shipping Control Ticket) and/or other appropriate forms specified by the commissioner depending on the waste types involved.

e. E and P Waste intended for temporary use must be stored at the receiving wellsite in an above ground storage tank or a lined production pit which conforms to the liner requirements and operational provisions of LAC 43:XIX.307.A.

2. The Commissioner of Conservation, the Secretary of the Department of Natural Resources, and the State of Louisiana shall be held harmless from and indemnified for any and all liabilities arising from temporary use of E and P waste pursuant to this Subsection, and the operator of record and the surface owner shall execute agreements as the commissioner requires for this purpose.

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Chapter 5. Off-Site Storage, Treatment and/or Disposal of Exploration and Production Waste Generated from Drilling and Production of Oil and Gas Wells

Exploration and Production Waste (E and P Waste)—drilling wastes, salt water, and other wastes associated with the exploration, development, or production of crude oil or natural gas wells and which is not regulated by the provisions of, and, therefore, exempt from the Louisiana Hazardous Waste Regulations and the Federal Resource Conservation and Recovery Act, as amended. E and P Wastes include, but are not limited to the following.

Waste Type	E and P Waste Description
01	Salt water (produced brine or produced water), except for salt water whose intended and actual use is in drilling, workover or completion fluids or in enhanced mineral recovery operations, process fluids generated by approved salvage oil operators who only receive oil (BS&W) from oil and gas leases, and nonhazardous natural gas plant processing waste fluid which is or may be commingled with produced formation water.
02	Oil-base drilling wastes (mud, fluids and cuttings).
03	Water-base drilling wastes (mud, fluids and cuttings).
04	Completion workover and stimulation fluids.

9.1.11 Mississippi

Regulatory Authority: Mississippi Oil and Gas Board

Reference Source: State of Mississippi Statues, Rules of Procedures, Statewide Rules and Regulations

Rule 26. Requirements for Hydraulic Fracture Stimulation –Report of Shooting or Treating

2. The provisions of this Rule shall apply to oil and gas wells which are proposed to undergo a temporary or intermittent hydraulic fracturing procedure to improve the productive capacity of such oil and gas wells utilizing Hydraulic Fracturing Treatment as hereinabove defined.

3. Before an operator shall commence the hydraulic fracturing of any oil and gas well, including the application of Hydraulic Fracturing Treatment as hereinabove defined, such operator shall file with the Mississippi State Oil and Gas Board a duly executed FORM 2 indicating in the narrative portion of such FORM 2 the nature of the hydraulic fracturing procedure proposed to be conducted. No such hydraulic fracturing procedure shall commence prior to the approval of such permit application. Operator shall provide the Mississippi State Oil and Gas Board Field Inspector with not less than forty-eight (48) hours notice in advance of the commencement of any Hydraulic Fracturing Treatment.

4. Operators applying for a permit to commence Hydraulic Fracturing Treatment of any oil or gas well shall state clearly such intent on the FORM 2 submitted to the Mississippi State Oil and Gas Board in accordance with Paragraph 5 below.

5. The permit application described in the preceding paragraphs shall, at a minimum, include:

> (A.) The following information on the existing or proposed casing program, demonstrating that the well will have steel alloy casing designed to withstand the anticipated maximum injection pressures to which the casing will be subjected in the well:
>
> > (1) Whether the well is or will be a vertical well, a directional well or a horizontal well; and

(2) The estimated true vertical and measured production casing setting depths in the well; and

(3) The casing grade and minimum internal yield pressure for the existing or proposed production casing used in the well; and

(4) The surface casing shall be set at least 100.0 feet below the Base Underground Source of Drinking Water (“BUSDW”) and cemented to the surface or the intermediate or production string casing shall have cement to the surface starting 100.0 feet below the BUSDW or the operator shall use tubing and packer to perform the Hydraulic Fracturing Treatment.

(B.) The following information demonstrating that the well has or will have sufficient cement volume and integrity to prevent the movement of Base Fluids and Additives up-hole into the various casing or well bore annuli:

(1) The existing or proposed cement minimum compressive strength; and

(2) The known or estimated top of cement for the production casing string.

(C.) The anticipated surface treating pressure range for the proposed Hydraulic Fracturing Treatment. The production casing described in subparagraph 5.(A.) above shall be sufficient to contain the maximum anticipated treating pressure of the proposed Hydraulic Fracturing Treatment which shall not exceed the API minimum internal yield pressure for such production casing.

6. Within thirty (30) days following the completion of the Hydraulic Fracturing Treatment, the operator shall, for the purpose of disclosure, report the following information to the Supervisor regarding such procedure utilizing a duly executed FORM 3 (“Completion Report”):

(A.) The maximum pump pressure measured at the surface during each stage of the Hydraulic Fracturing Treatment unless reasonable grounds for confidentiality exist in which event a

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request for confidentiality may be submitted to the Supervisor who shall be authorized to waive the

disclosure of such data for a period of six (6) months and for an additional six (6) months upon written request to the Supervisor at the Supervisor's sole discretion; and

(B.) The types and volumes of the Base Fluids and Additives used for each stage of the Hydraulic Fracturing Treatment expressed in gallons or pounds; and

(C.) The calculated fracture height as designed to be achieved during the Hydraulic Fracturing Treatment and the estimated TVD to the top of the fracture; and

(D.) A list of all Additives used during the Hydraulic Fracturing Treatment specified by general type, such as acids, biocides, breakers, corrosion inhibitors, cross-linkers, demulsifiers, friction reducers, gels, iron controls, oxygen scavengers, pH adjusting agents, scale inhibitors, proppants and surfactants; and

(E.) For each additive type listed under subparagraph 6.(D.) above, the specific trade name and suppliers of all the Additives utilized during the Hydraulic Fracturing Treatment; and

(F.) If the operator causes any Additives to be used during the Hydraulic Fracturing Treatment not otherwise disclosed by the person performing such treatment, the operator shall disclose a list of all Chemical Constituents and associated CAS numbers contained in such Additives that are subject to the requirements of 29 CFR 1910.1200(g)(2); and

(G.) A list of Chemical Constituents intentionally added to the Base Fluids which are subject to the requirements of 29 CFR Section 1910.1200(g)(2) and their associated CAS numbers; and

(H.) The maximum ingredient concentrations within the Additive expressed as a percent by mass for each chemical ingredient listed under subparagraph 6.(G.) above; and

(I.) The maximum concentration of each chemical ingredient listed under subparagraph 6.(G.) above expressed as a percent by mass of the total volume of Hydraulic Fracturing Fluids utilized.

9.1.12 Montana

Regulatory Authority: Montana Department of Natural Resources

Reference Source: Rule Chapter: 36.22 Oil and Gas Conservation

36.22.1106 SAFETY AND WELL CONTROL REQUIREMENTS – HYDRAULIC FRACTURING

(1) New and existing wells which will be stimulated by hydraulic fracturing must demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed.

(2) Prior to initiation of fracture stimulation, the operator must evaluate the well. If the operator proposes hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. If the casing fails the pressure test it must be repaired or the operator must use a temporary casing string (fracturing string).

> (a) If the operator proposes hydraulic fracturing though a fracturing string, it must be stung into a liner or run on a packer set not less than 100 feet below the cement top of the production or intermediate casing and must be tested to not less than maximum anticipated treating pressure minus the annulus pressure applied between the fracturing string and the production or immediate casing.

(3) A casing pressure test will be considered successful if the pressure applied has been held for 30 minutes with no more than ten percent pressure loss.

(4) A pressure relief valve(s) must be installed on the treating lines between pumps and wellhead to limit the line pressure to the test pressure determined above; the well must be equipped with a remotely controlled shut-in device unless waived by the board administrator should the factual situation warrant.

(5) The surface casing valve must remain open while hydraulic fracturing operations are in progress; the annular space between the fracturing string and the intermediate or production casing must be

monitored and may be pressurized to a pressure not to exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.

36.22.1015 DISCLOSURE OF WELL STIMULATION FLUIDS

(1) The owner or operator of a well shall, upon completion of the well, provide the board, on its Form No. 4 for a new well or Form No. 2 for an existing well:

(a) a description of the interval(s) or formation treated;

(b) the type of treatment pumped (acid, chemical, fracture stimulation); and

(c) the amount and type(s) of material pumped and the rates and maximum pressure during treatment.

(2) For hydraulic fracturing treatments the description of the amount and type of material used must include:

(a) a description of the stimulation fluid identified by additive type (e.g. acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant); and

(b) the chemical ingredient name and the Chemical Abstracts Service (CAS) Registry number, as published by the Chemical Abstracts Service, a division of the American Chemical Society (www.cas.org), for each ingredient of the additive used. The rate or concentration for each additive shall be provided in appropriate measurement units (pounds per gallon, gallons per thousand gallons, percent by weight or percent by volume, or parts per million).

(3) To comply with the requirements of this section, the owner or operator may submit:

(a) the service contractor's job log;

(b) the service company's final treatment report (without any cost/pricing data);

(c) an owner or operator's well treatment job log; or

(d) other report providing the above required information.

(4) The administrator may waive all or a portion of the requirements in (2) or (3) of this rule if:

(a) the owner or operator demonstrates that it has posted the required information to the Interstate Oil and Gas Compact Commission/Groundwater Protection Council hydraulic fracturing web site (FracFocus.org); or

(b) a successor web site to FracFocus.org or other publically accessible Internet information repositories that the board may choose to accept.

36.22.1016 PROPRIETARY CHEMICALS AND TRADE SECRETS

(1) As provided in 30-14-402, MCA, where the formula, pattern, compilation, program, device, method, technique, process, or composition of a chemical product is unique to the owner or operator or service contractor and would, if disclosed, reveal methods or processes entitled to protection as trade secrets, such a chemical need not be disclosed to the board or staff. The owner, operator, or service contractor may identify the trade secret chemical or product by trade name, inventory name, chemical family name, or other unique name and the quantity of such constituent(s) used.

(2) If necessary to respond to a spill or release of a trade secret product the owner, operator, or service contractor must provide to the board or staff, upon request, a list of the chemical constituents contained in a trade secret product. The administrator may request information be provided orally or be provided directly to a laboratory or other third party performing analysis for the board. Board members, board staff, and any third parties receiving trade secret information on behalf of the board may be required to execute a nondisclosure agreement.

(3) The owner, operator, or service contractor must also provide the chemical constituents of a trade secret product to a health professional who provides a written statement that knowledge of the chemical constituents of such product is needed for purposes of diagnosis or treatment of an individual and the individual being diagnosed or treated may have been exposed to the chemical concerned. The

health professional may not use the information for purposes other than the health needs asserted in the statement of need, and may be required to execute a nondisclosure agreement.

(4) Where a health professional determines that a medical emergency exists and the chemical constituents of a trade secret product are necessary for emergency treatment, the owner, operator, or service contractor shall immediately disclose the chemical constituents of a product to that health professional upon a verbal acknowledgement by the health professional that such information shall not be used for purposes other than the health needs asserted and that the health professional shall otherwise maintain the information as confidential. The owner or operator or service contractor may request a written statement of need, and a confidentiality agreement from a health professional as soon as circumstances permit.

36.22.1106 SAFETY AND WELL CONTROL REQUIREMENTS – HYDRAULIC FRACTURING

(1) New and existing wells which will be stimulated by hydraulic fracturing must demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed.

(2) Prior to initiation of fracture stimulation, the operator must evaluate the well. If the operator proposes hydraulic fracturing through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. If the casing fails the pressure test it must be repaired or the operator must use a temporary casing string (fracturing string).

> (a) If the operator proposes hydraulic fracturing though a fracturing string, it must be stung into a liner or run on a packer set not less than 100 feet below the cement top of the production or intermediate casing and must be tested to not less than maximum anticipated treating pressure minus the annulus pressure applied between the fracturing string and the production or immediate casing.

(3) A casing pressure test will be considered successful if the pressure applied has been held for 30 minutes with no more than ten percent pressure loss.

(4) A pressure relief valve(s) must be installed on the treating lines between pumps and wellhead to limit the line pressure to the test pressure determined above; the well must be equipped with a remotely controlled shut-in device unless waived by the board administrator should the factual situation warrant.

(5) The surface casing valve must remain open while hydraulic fracturing operations are in progress; the annular space between the fracturing string and the intermediate or production casing must be monitored and may be pressurized to a pressure not to exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.

36.22.1010 WORK-OVER, RECOMPLETION, WELL STIMULATION – NOTICE AND APPROVAL

(1) No well may be reperforated, recompleted, reworked, chemically stimulated, or hydraulically fractured without first notifying the board on Form No. 2 and receiving approval from the administrator or other authorized representative of the board. Within 30 days following completion of the well work, a subsequent report of the actual work performed must be submitted on Form No. 2.

(2) Well repairs, including tubing, pump, sucker rod replacement or repair, repairs and reconfiguration of well equipment which do not substantially change the mechanical configuration of the well bore or casing, and hot oil treatments do not require prior approval or a subsequent report. Acid and chemical treatments of less than 10,000 gallons and similar treatments intended to clean perforations, remove scale or paraffin, or remedy near-well bore damage do not require prior approval, but do require a subsequent report of the actual work performed submitted on Form No. 2 within 30 days following completion of the work.

9.1.13 Nebraska

Regulatory Authority: Nebraska Oil and Gas Conservation Commission

Reference Source: Rules and Regulations of the Nebraska Oil and Gas Conservation Commission

041 WELL STIMULATION ACTIVITIES COVERED BY DRILLING PERMITS

Well completions which include hydraulic fracturing, acidizing, or other chemical stimulations done to complete a well are considered permitted under the drilling permit for that well.

042 HYDRAULIC FRACTURING

New and existing wells which will be stimulated by hydraulic fracturing must demonstrate suitable and safe mechanical configuration for the stimulation treatment proposed.

042.01 Prior to the initiation of fracture stimulation, the operator must evaluate the well. If the operator proposes stimulation through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. If the casing fails the pressure test, it must be repaired or the operator must use a temporary casing/tubing (fracturing string).

042.02 If the operator proposed fracturing through a temporary casing/tubing string it must be stung into a liner or run on a packer set not less than one hundred (100) feet below the cement top of the production or intermediate casing and must be tested to not less than maximum anticipated treating pressure.

042.03 Casing/tubing pressure test will be considered successful if the pressure applied has been held for ten (10) minutes with no more than a ten percent pressure loss.

042.04 Maximum treating pressure shall not exceed the test pressure determined above.

042.05 The surface casing valve must remain open while hydraulic fracturing operations are in progress. The annular space between the fracturing string and production casing must be monitored and may be pressurized to a pressure not to exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.

043 DISCLOUSURE OF WELL STIMULATION FLUIDS

Within sixty (60) days of the hydraulic fracture stimulation is performed, the operator shall post on the FracFocus Chemical Disclosure Registry (FracFocus.org) all the elements made viewable by the FracFocus website.

044 PROPRIETARY CHEMICALS AND TRADE SECRETS

Where the formula, pattern, compilation, program, device, method, technique, process or composite of a chemical product is proprietary to the owner or operator, or service company and would if disclosed reveal methods or processes entitled to protection as trade secrets, such as a chemical, need not be disclosed to the Director or staff unless:

044.01 If necessary to respond to a spill or release of a trade secret product, the operator ofr service company must provide to the Director upon request a list of the chemical constituents contained in a trade secret product. The Director may request information be provided orally directly to a laboratory or other third party performing analysis for the Commission. Commission staff and any third parties receiving trade secret information on behalf of the Commission may be required to execute a nondisclosure agreement.

044.02 The Operator or service company must provide the chemical constituents of a trade secret to a health professional who provides a written statement that knowledge of the chemical constituents of such product is needed for purposes of diagnosis or treatment of the individual being diagnosed or treated may have been exposed to the chemical concerned. The health professional may not use the information for purposes other that the health needs asserted in the statement of need and may be required to execute a nondisclosure agreement.

44.03 Where a health professional determines that a medical emergency exists and the chemical constituents of a trade secret product are necessary for emergency treatment, the operator or service company shall immediately disclose the chemical constituents to a product to that health professional upon verbal acknowledgement by the health professional that such information shall not be used for purposes other than health needs asserted and that the health professional shall otherwise maintain the information as confidential.

9.1.14 Nevada

Regulatory Authority: Nebraska Oil and Gas Conservation Commission

Reference Source: Adopted Regulation of the Commission on Mineral Resources, LCB File No. R011-14

Sec. 9.

1. Except as otherwise provided in subsections 2 and 4, an operator shall collect an initial baseline sample and subsequent monitoring samples from each available water source, not to exceed four available water sources, located within the sampling area. If more than four available water sources are located within the sampling area, the operator shall select the four available water sources for sampling based on:

(a) The proximity of the available water sources to the proposed oil or gas well. Available water sources closest to the proposed oil or gas well are preferred.

(b) The orientation of the sampling locations relative to the available water sources. To the extent that the direction of the flow of groundwater is known or can reasonably be inferred, sample locations from both down-gradient and up-gradient locations are preferred over cross-gradient locations.

(c) The depth of the available water sources. The sampling of the deepest of the available water sources is preferred.

(d) The condition of the available water sources. An operator is not required to sample an available water source if the Administrator determines that the available water source is improperly maintained or nonoperational, or has physical characteristics which would prevent the safe collection of a representative sample or which would require nonstandard sampling equipment.

(e) The construction and use of the water source. If an operator constructs a temporary well within the sampling area to use as a water source for the purpose of supporting the drilling or operation of an oil or gas well, the operator must include the water source as an available water source for the purpose of sampling and monitoring pursuant to this section.

2. An operator may, before a well is spudded or drilled for oil or gas, request an exception from the requirements of this section by filing a sundry notice (Form 4) with the Administrator. The Administrator may grant the request for an exception if the Administrator finds that:

(a) No available water sources are located within the sampling area;

(b) The only available water sources are unsuitable pursuant to paragraph (d) of subsection 1; or

(c) Each owner of a water source that is suitable for testing and located within the sampling area has refused to grant the operator access to the water source for sampling and additionally finds that the operator has made a reasonable and good faith effort to obtain the consent of the owner to conduct the sampling.

An operator seeking an exception on the grounds set forth in paragraph (b) shall provide to the Administrator documentation of the conditions of each available water source which is deemed unsuitable. An operator seeking an exception on the grounds set forth in paragraph (c) shall provide to the Administrator documentation of the efforts of the operator to obtain the consent of each owner of a water source.

3. Except as otherwise provided in subsections 2 and 4, an operator shall collect from each available water source for which the operator is required to collect samples pursuant to this section:

(a) An initial sample during the 12-month period immediately preceding the commencement of hydraulic fracturing at an oil or gas well.

(b) A first subsequent sample, collected not earlier than 6 months but not later than 12 months after the commencement of hydraulic fracturing. If a well that has been drilled produces hydrocarbons for a period of less than 6 months after the commencement of hydraulic fracturing and the well is subsequently plugged and abandoned, or if the well is plugged and abandoned without having produced hydrocarbons after the commencement of hydraulic fracturing, the operator shall collect each first subsequent sample at the time the well is plugged.

(c) A second subsequent sample, collected not earlier than 60 months but not later than 72 months after the commencement of hydraulic fracturing. If a well that has been drilled produces hydrocarbons for a period of less than 60 months and the well is subsequently plugged and abandoned, the operator shall collect each second subsequent sample at the time the well is plugged. An operator is not required to collect second subsequent samples if a well that is drilled is plugged and abandoned without having produced hydrocarbons.

4. For the purposes of satisfying the requirements for sampling available water sources pursuant to paragraphs (a) and (b) of subsection 3, an operator may rely on the test results of a previous sample from an available water source if:

(a) The previous sample was collected and tested during the respective period prescribed for sampling pursuant to paragraph (a) or (b) of subsection 3.

(b) The procedure for collecting and testing the sample, and the constituents for which the sample was tested, are substantially similar to those required by this section.

(c) The Administrator receives the test results not less than 14 days before the commencement of hydraulic fracturing.

5. The Administrator may require an operator to collect and test samples of an available water source in addition to the collection and testing protocol prescribed by this section if the Administrator finds that additional testing is warranted.

6. The testing of a water sample pursuant to this section must be conducted by a laboratory certified pursuant to NAC 445A.0552 to 445A.067, inclusive. Upon request, an operator shall provide his or her protocol for collection and testing to the Administrator.

7. The test results of initial and subsequent samples collected pursuant to this section must include, without limitation:

(a) The level of each analyzed constituent identified in the routine domestic water analysis of the Nevada State Public Health Laboratory of the University of Nevada School of Medicine.

(b) The levels of benzene, toluene, ethylbenzene and xylene.

(c) The levels of dissolved methane, ethane, propane and hydrogen sulfide gases within the sample.

8. If a dissolved methane concentration greater than 10 milligrams per liter (mg/l) is detected in a sample of water collected pursuant to this section, an analysis of the gas composition, including, without limitation, an analysis of the stable isotope ratios of carbon (13C vs. 12C) and hydrogen (2H vs. 1H) and an analysis of the origin (biogenic vs. thermogenic), must be performed on the sample using gas chromatography and mass spectrometry, as necessary.

9. An operator shall immediately notify the Administrator and the owner of an available water source if the test results of a sample collected pursuant to this section indicate:

(a) The presence of benzene, toluene, ethylbenzene, xylene or hydrogen sulfide in a concentration greater than the specified maximum contaminant level set forth in the primary and secondary standards for drinking water pursuant to NAC 445A.453 and 445A.455.

(b) If the sample is a subsequent sample, any change in water chemistry indicative of a degradation in water quality.

10. An operator shall provide copies of the test results of each sample collected pursuant to this section to the Administrator and to the respective owner of the available water source not later than 30 days after the operator receives the test results from a laboratory. The Division will, upon request, make the test results available to a member of the public for inspection at the office of the Division located in Carson City.

11. An operator shall include with the copy of the test results of a sample provided pursuant to subsection 10 a description of the location of the available water source and any field observations recorded by the operator during the collection of the sample. The operator shall describe the location of

the available water source by public land survey and the county assessor's parcel number and shall include the global positioning system coordinates of the available water source in the manner prescribed by subparagraph (2) of paragraph (b) of subsection 2 of NAC 534.340.

12. An operator shall not commence hydraulic fracturing at a well until the operator has complied with subsections 1, 2 and 4 to 11, inclusive, and paragraph (a) of subsection 3.

13. As used in this section, "public land survey" has the meaning ascribed to it in NAC 534.185.

Sec. 10

1. An operator must include with his or her application to drill an oil or gas well:

(a) The water appropriation permit number and the name of the owner of each water source within the area of review that is on file with the Division of Water Resources of the State Department of Conservation and Natural Resources.

(b) The well log number, well depth and the diameter of the water well casing.

(c) The static water level below the surface of the ground or the rate of flow of the water, if any.

(d) A description of the location of each water source located within the area of review in the manner prescribed by subsection 11 of section 9 of this regulation.

(e) Publically available maps and cross-sections of the area of review which describe the surface and subsurface geology of the area of review, including, without limitation, the location of known or suspected faults.

(f) A map showing the location of each water source or perennial stream located within the area of review, the overall project area or lease holdings, the boundaries of the area of review, all known well locations, land ownership and applicable assessor parcel numbers.

(g) The source and estimated volume of water required for hydraulic fracturing in each well.

(h) A plan for the management and disposal of all fluids to be used in the proposed hydraulic fracturing operation.

2. If an operator discovers inconsistencies with respect to publically available and proprietary hydrologic or geologic information within an area of review that the operator reasonably believes to be relevant with respect to potential contamination from hydraulic fracturing, the operator shall disclose the inconsistencies to the Division.

3. The Division may prescribe or an operator may specify an area of review that includes an area of land in addition to that area of land located within a radius of 1 mile of a proposed oil or gas well and any surface projection of any lateral component of the wellbore that is proposed for hydraulic fracturing for the purposes of compliance with this section or the collection of additional data based on population density, residential locations, water source locations or for other good cause as the Division or an operator may deem reasonable.

Sec. 11

In addition to the requirements prescribed by NAC 522.265, the operator of an oil or gas well shall:

1. Ensure that:

(a) The surface location of the well is at a lateral distance of not less than 300 feet from any known perennial water source, existing water well or existing permitted structure.

(b) The edge of the drilling pad is at a lateral distance of not less than 100 feet from any known perennial water source, existing water well or existing permitted structure.

An owner or an operator may request and the Division may approve an exception to the requirements prescribed by this subsection.

2. For the intermediate casing string installed in the well directly below the surface casing, install the intermediate casing string through the surface casing from the installed depth of the intermediate casing string to the surface of the ground.

3. For a production casing string, conduct a pressure test of the casing string in which the casing is pressurized to 3,000 pounds or more per square inch gauge (psig), not to exceed 80 percent of the burst-pressure rating of the casing, for a period of not less than 30 minutes. A pressure test must be conducted and the results of the test must be reported in the manner prescribed by subsection 7 of NAC 522.265.

Sec. 12

1. An operator of an oil or gas well shall:

(a) Not less than 14 days before the commencement of hydraulic fracturing

(1) Provide written notice to each owner of real property and any operator of an oil, gas or geothermal well located within the area of review of the hydraulic fracturing operation.

(2) Provide written notice to the board of county commissioners in the county in which the oil or gas well is located.

(3) Submit to the Division an affidavit (Form 15) certifying that each strata is sealed and isolated with casing and cement in accordance with NAC 522.260. The affidavit must be signed by the operator or a competent person designated by the operator and must incorporate and include a copy of each relevant cement evaluation log as evidence of compliance with NAC 522.260.

(4) Submit for approval by the Division a sundry notice (Form 4) and a report describing all specific aspects of the proposed hydraulic fracturing operation. The report must identify each stage of the hydraulic fracturing operation, the measured depth and true vertical depth below the surface of the ground for each stage, the duration of each stage, all intervals to be perforated in measured depth and true vertical depth below

the surface of the ground, the number and diameter of perforations per foot and the estimated hydraulic pressures to be utilized.

(b) Maintain a record as to the manner in which each owner, operator and board of county commissioners was notified pursuant to subparagraphs (1) and (2) of paragraph (a), including, without limitation, the method of notification.

(c) Before the commencement of hydraulic fracturing:

(1) Ensure that each chemical used in the hydraulic fracturing process is identified on the Internet website maintained by the Division as a chemical which is approved by the Division for hydraulic fracturing. An operator may request and the Division may approve the use of a chemical that is not identified as an approved chemical if the operator submits the request to the Division on a sundry notice (Form 4) not less than 30 days before the commencement of hydraulic fracturing.

(2) Disclose to the Division each additive that the operator intends to use in the hydraulic fracturing fluid, including, without limitation, any additive that may be protected as a trade secret. The operator shall include with the identity of each additive the trade name and vendor of the additive and a brief description of the intended use or function of the additive.

2. The operator shall monitor and record all well head pressures, including each annular space pressure, during the hydraulic fracturing operation. The maximum hydraulic pressure to which a segment of casing is exposed must not exceed the burst-pressure rating of the casing, but the Division may require a lower maximum hydraulic pressure as the Division determines is necessary. The operator shall immediately stop the hydraulic fracturing process and notify the Division if any change in annular space pressure is observed which suggests communication with the hydraulic fracturing fluids. The operator shall provide the Division with a report documenting all recorded hydraulic fracturing pressures for each stage of the hydraulic fracturing operation not later than 15 days after the completion of each stage.

3. The operator shall contain all liquids that are returned to the surface and discharged from the wellbore at the conclusion of each stage of the hydraulic fracturing operation. The operator shall contain the liquids in enclosed tanks or in the manner prescribed by the Division of Environmental Protection pursuant to chapters 445A of NRS and 445A of NAC.

4. Except as otherwise provided in subsection 5 and not later than 60 days after the completion of a hydraulic fracturing operation, the operator shall report, at a minimum, to the Internet website www.fracfocus.org for inclusion in FracFocus, or its successor registry:

(a) The name of the operator, the well name and well number and the American Petroleum Institute well number.

(b) The date of the hydraulic fracturing treatment, the county in which the well is located, any public land surveys relevant to the location of the well and the global positioning system coordinates of the well.

(c) The true vertical depth of the well and the total volume of water used in the hydraulic fracturing treatment of the well or if the operator utilizes a base fluid other than water, the type and total volume of the base fluid used in the hydraulic fracturing treatment.

(d) The identity of each additive used in the hydraulic fracturing fluid, including, without limitation, the trade name and vendor of the additive and a brief description of the intended use or function of the additive.

(e) The identity of each chemical intentionally added to the base fluid.

(f) The maximum concentration, measured in percent by mass, of each chemical intentionally added to the base fluid.

(g) The Chemical Abstracts Service Registry Number for each chemical intentionally added to the base fluid, if applicable.

5. Proprietary information with respect to a trade secret does not constitute public information and is confidential. An operator may submit a request to the Division to protect from disclosure any information which, under generally accepted business practices, would be considered a trade secret or other confidential proprietary information of the business. The Administrator shall, after consulting with the operator, determine whether to protect the information from disclosure. If the Administrator determines to protect the information from disclosure, the protected information:

(a) Is confidential proprietary information of the operator.

(b) Is not a public record.

(c) Must be redacted by the Administrator from any report that is disclosed to the public.

(d) May only be disclosed or transmitted by the Division:

(1) To any officer, employee or authorized representative of this State or the United States:

(I) For the purposes of carrying out any duties pursuant to the provisions of this chapter or chapter 522 of NRS; or

(II) If the information is relevant in any judicial proceeding or adversary administrative proceeding under this chapter or chapter 522 of NRS or under the provisions of any federal law relating to oil or gas wells or hydraulic fracturing, and the information is admissible under the rules of evidence; or

(2) Upon receiving the consent of the operator.

The disclosure of any proprietary information pursuant to this subsection must be made in a manner which preserves the status of the information as a trade secret.

6. The Division shall make available to the public for inspection any information, other than a trade secret or other proprietary information that is maintained confidentially pursuant to subsection 5, that is submitted by an operator pursuant to this section.

7. As used in this section, “trade secret” has the meaning ascribed to it in NRS 600A.030.

Sec. 13

1. Notwithstanding any provision of sections 2 to 12, inclusive, of this regulation to the contrary, an operator of an oil or gas well that was drilled and spudded before October 24, 2014, may request approval from the Division to conduct a hydraulic fracturing operation at the oil or gas well by submitting a sundry notice (Form 4) to the Division. The sundry notice must include, without limitation:

(a) A cement evaluation log of the production casing string that has been conducted not less than 5 years before the submission of the sundry notice.

(b) A pressure test of the production casing string conducted in the manner prescribed by subsection 7 of NAC 522.265.

(c) Any other information required by the Division.

2. The Division will, upon receipt of a request pursuant to subsection 1, evaluate each well design which is the subject of the request and approve or disapprove the request.

9.1.15 New Mexico

Regulatory Authority: New Mexico Oil Conservation Commission

Reference Source: Title 19 – Natural Resources and Wildlife, Chapter 15. Oil and Gas

19.15.16.17 Shooting and Chemical Treatment of Wells:

If shooting, fracturing or treating a well injures the producing formation, injection interval, casing or casing seat and may create underground waste or contaminate fresh water, the operator shall within five working days notify in writing the division and proceed with diligence to use the appropriate method and means for rectifying the damage. If shooting, fracturing or chemical treating results in the well's irreparable injury the division may require the operator to properly plug and abandon the well.

19.15.16.19 Log, Completion and Workover Reports:

B. For a hydraulically fractured well, the operator shall also complete and file the division's hydraulic fracturing disclosure form within 45 days after completion of the well. The hydraulic fracture disclosure form shall include the well API number; the well name; the well number; the well location by unit, lot, section, township and range; the county where the well is located; the well's surface and bottom hole locations by footage from the section line; the operator's name and address; the operator's OGRID; the operator's phone number; the fracture date; the well's production type (oil or gas); the pool code; the well's gross fractured interval; the well's true vertical depth; the total volume of fluid pumped; and a description of the hydraulic fluid composition and concentration listing each ingredient and for each ingredient the trade name, supplier, purpose, chemical abstract service number, maximum ingredient concentration in additive as percentage by mass, maximum ingredient concentration in the hydraulic fracturing fluid as percentage by mass; certification by the operator that the information included on the hydraulic fracture disclosure form is true and complete to the best of the operator's knowledge and belief; and the signature, printed name, e-mail address and title of the operator or operator's designated representative. The division does not require the reporting of information beyond the material safety data sheet data as described in 29 C.F.R. 1910.1200. The division does not require the reporting or disclosure of proprietary, trade secret or confidential business information.

9.1.16 North Dakota

Regulatory Authority: North Dakota Industrial Commission

Reference Source: North Dakota Administrative Code, Rules and Regulations

43-02-03-27. PERFORATING, FRACTURING, AND CHEMICALLY TREATING WELLS.

The director may prescribe pretreatment casing pressure testing as well as other operational requirements designed to protect wellhead and casing strings during treatment operations. If damage results to the casing or the casing seat from perforating, fracturing, or chemically treating a well, the operator shall immediately notify the director and proceed with diligence to use the appropriate method and means for rectifying such damage, pursuant to section 43-02-03-22. If perforating, fracturing, or chemical treating results in irreparable damage which threatens the mechanical integrity of the well, the commission may require the operator to plug the well.

43-02-03-27.1 HYDRAULIC FRACTURE STIMULATION.

1. For hydraulic fracture stimulation performed through a frac string run inside the intermediate casing string:

   a. The frac string must be either stung into a liner or run with a packer set at a minimum depth of one hundred feet [30.48 meters] below the top of cement or one hundred feet [30.48 meters] below the top of the Inyan Kara formation, whichever is deeper.

   b. The intermediate casing-frac string annulus must be pressurized and monitored during frac operations.

   c. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should the relief valve open. The relief valve must be set to limit line pressure to no more than eighty-five percent of the internal yield pressure of the frac string.

d. An adequately sized, function tested pressure relief valve and an adequately sized diversion line must be utilized to divert flow from the intermediate casing to a pit or containment vessel in case of frac string failure. The relief valve must be set to limit annular pressure to no more than eighty-five percent of the lowest internal yield pressure of the intermediate casing string or no greater than the pressure test on the intermediate casing, less one hundred pounds per square inch gauge, whichever is less.

e. The surface casing must be fully open and connected to a diversion line rigged to a pit or containment vessel.

f. An adequately sized, function tested remote operated frac valve must be utilized at a location on the christmas tree that provides isolation of the well bore from the treating line and must be remotely operated from the edge of the location or other safe distance.

g. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

2. For hydraulic fracture stimulation performed through an intermediate casing string:

a. The maximum treating pressure shall be no greater than eighty-five percent of the American petroleum institute rating of the intermediate casing.

b. Casing evaluation tools to verify adequate wall thickness of the intermediate casing shall be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation and a visual inspection with photographs shall be made of the top joint of the intermediate casing and the wellhead flange. If the casing evaluation tool or visual inspection indicates wall thickness is below the American petroleum institute minimum or a lighter weight of intermediate casing than the well design called for, calculations must be made to determine the reduced pressure rating. If the reduced pressure rating is less than the anticipated treating pressure, a frac string shall be run inside the intermediate casing.

c. Cement evaluation tools to verify adequate cementing of the intermediate casing shall be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation.

(1) If the cement evaluation tool indicates defective casing or cementing, a frac string shall be run inside the intermediate casing.

(2) If the cement evaluation tool indicates the top of cement behind the intermediate casing is below the top of the Mowry formation, a frac string shall be run inside the intermediate casing.

d. The intermediate casing and wellhead must be pressure tested to a minimum depth of one hundred feet [30.48 meters] below the top of the Tyler formation for at least thirty minutes with less than five percent loss to a pressure equal to or in excess of the maximum frac design pressure.

e. If the pressure rating of the wellhead does not exceed the maximum frac design pressure, a wellhead and blowout preventer protection system must be utilized during the frac.

f. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should the relief valve open. The relief valve must be set to limit line pressure to no greater than the test pressure of the intermediate casing, less one hundred pounds per square inch [689.48 kilopascals].

g. The surface casing valve must be fully open and connected to a diversion line rigged to a pit or containment vessel.

h. An adequately sized, function tested remote operated frac valve must be utilized between the treating line and the wellhead.

i. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

3. If during the stimulation, the pressure in the intermediate casing-surface casing annulus exceeds three hundred fifty pounds per square inch [2413 kilopascals] gauge, the owner or operator shall verbally notify the director as soon as practicable but no later than twenty-four hours following the incident.

9.1.17 Ohio

Regulatory Authority: Ohio Department of Natural Resources

Reference Source: Ohio Administrative Code, 1501:9 Division of Mineral Resources Management - Oil and Gas

1501:9-1-08 Well construction

(5) During stimulation or workover operations, all annuli shall be pressure-monitored. Stimulation or workover operations shall be immediately suspended for any inexplicable pressure deviation above those anticipated increases caused by pressure or thermal transfer. In the event that stimulation fluids circulate, or annular pressures deviate from anticipated, the owner shall immediately notify the inspector and acquire approval for remediation of casing or cement. If the chief determines that the stimulation of the well has resulted in irreparable damage to the well, the chief shall order that the well be plugged and abandoned within thirty days of issuance of the order.

(7) Production casing and liners.

(a) Cemented completions.

(ii) When cementing the production string of a well that will be stimulated by hydraulic fracturing, and the uppermost perforation is less than five hundred feet below the base of the deepest USDW, sufficient cement shall be used to fill the annular space outside the casing from the seat to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the owner shall notify the inspector and perform tests approved by the inspector. After the top of cement outside the casing is determined, the owner or his authorized representative shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations.

1509.19 Well stimulation.

An owner who elects to stimulate a well shall stimulate the well in a manner that will not endanger underground sources of drinking water. Not later than twenty-four hours before commencing the stimulation of a well, the owner or the owner's authorized representative shall notify an oil and gas resources inspector. If during the stimulation of a well damage to the production casing or cement occurs and results in the circulation of fluids from the annulus of the surface production casing, the owner shall immediately terminate the stimulation of the well and notify the chief of the division of oil and gas resources management. If the chief determines that the casing and the cement may be remediated in a manner that isolates the oil and gas bearing zones of the well, the chief may authorize the completion of the stimulation of the well. If the chief determines that the stimulation of a well resulted in irreparable damage to the well, the chief shall order that the well be plugged and abandoned within thirty days of the issuance of the order.

For purposes of determining the integrity of the remediation of the casing or cement of a well that was damaged during the stimulation of the well, the chief may require the owner of the well to submit cement evaluation logs, temperature surveys, pressure tests, or a combination of such logs, surveys, and tests.

UNIVERSITY of HOUSTON

9.1.18 Oklahoma

Regulatory Authority: Oklahoma Corporation Commission

Reference Source: Title 165. Corporation Commission, Chapter 10. Oil and Gas Conservation

SUBCHAPTER 3. Drilling, Developing, and Producing

Part 1. Drilling

165:10-3-4. Casing, cementing, wellhead equipment, and cementing reports

(e) Notice of hydraulic fracturing operations. The operator shall give at least 48 hours notice by telephone, facsimile or electronic mail to the appropriate Conservation Division District Office or Field Inspector concerning the time when hydraulic fracturing operations will begin. Separate stages of a planned multi-stage hydraulic fracturing operation shall not constitute separate hydraulic fracturing operations for notification purposes.

PART 3. COMPLETIONS

165:10-3-10. Well completion operations

(a) Hydraulic fracturing and acidizing. In the completion of an oil, gas, injection, disposal, or service well, where acidizing or fracture processes are used, no oil, gas, or deleterious substances shall be permitted to pollute any surface or subsurface fresh water.

(b) Chemical disclosure. Within 60 days after the conclusion of hydraulic fracturing operations on an oil, gas, injection, disposal, or service well that is hydraulically fractured, the operator must submit information on the chemicals used in the hydraulic fracturing operation to the FracFocus Chemical Disclosure Registry or, alternatively, submit the information directly to the Commission. If the chemical disclosure information is submitted directly to the Commission under this subsection, the Commission will post such information on the FracFocus Chemical Disclosure Registry.

(1) The submission required by this subsection must include the following information:

(A) the name of the operator;

(B) the API number of the well;

(C) the longitude and latitude of the surface location of the well;

(D) the dates on which the hydraulic fracturing operation began and ended;

(E) the total volume of base fluid used in the hydraulic fracturing operation;

(F) the type of base fluid used;

(G) the trade name, supplier, and general purpose of each chemical additive or other substance intentionally added to the base fluid; and

(H) for each ingredient in any chemical additive or other substance intentionally added to the base fluid, the identity, Chemical Abstract Service (CAS) number, and maximum concentration. The maximum concentration for any ingredient must be presented as the percent by mass in the hydraulic fracturing fluid as a whole, and is not required to be presented as the percent by mass in any particular additive.

(2) For purposes of this subsection, the phrase “chemical additive or other substance intentionally added to the base fluid” refers to a substance knowingly and purposefully added to the base fluid and does not include trace amounts of impurities, incidental products of chemical reactions or processes, or constituents of natural materials.

(3) The operator is not responsible for inaccurate information provided to the operator by a vendor or service provider, but the operator is responsible for ensuring such information is corrected when any inaccuracy is discovered.

(4) If certain chemical information, such as the chemical identity, CAS number, and/or maximum concentration of an ingredient, is claimed in good faith to be entitled to protection as a trade secret under the Uniform Trade Secrets Act, 78 O.S. §§85-94, the submission to the FracFocus Chemical Disclosure Registry may note the proprietary nature of that chemical information

instead of disclosing the protected information to the registry. The submission must include the name of the supplier, service company, operator, or other person asserting the claim that the chemical information is entitled to protection as a trade secret and provide the chemical family name or similar descriptor for the chemical if the chemical identity and CAS number are not disclosed. The Commission or the Director of the Oil and Gas Conservation Division may require the claimant to file with the Commission a written explanation in support of the claim.

(5) Nothing in this subsection restricts the Commission's ability to obtain chemical information under the provisions of OAC 165:10-1-6 or other applicable Commission rules.

(6) This subsection applies to:

(A) horizontal wells that are hydraulically fractured on or after January 1, 2013; and

(B) other wells that are hydraulically fractured on or after January 1, 2014.

(c) Rule reference guide. References to Commission rules regarding management of hydraulic fracturing operations are as follows:

(1) Duties and authority of the Conservation Division (OAC 165:10-1-6).

(2) Required approval of notice of intent to drill, deepen, re-enter or recomplete; Permit to Drill (OAC 165:10-3-1).

(3) Surface and production casing (OAC 165:10-3-3).

(4) Casing, cementing, wellhead equipment and cementing reports (OAC 165:10- 3-4).

(5) Swabbing and bailing (OAC 165:10-3-11).

(6) Leakage prevention in tanks; protection of migratory birds (OAC 165:10- 3-13).

(7) Well site and surface facilities (OAC 165:10-3-17).

(8) Completion reports (OAC 165:10-3-25).

(9) Administration and enforcement of rules (OAC 165:10-7-2).

(10) Cooperation with other agencies (OAC 165:10-7-3).

(11) Water quality standards (OAC 165:10-7-4).

(12) Prohibition of pollution (OAC 165:10-7-5).

(13) Protection of municipal water supplies (OAC 165:10-7-6).

(14) Informal complaints, citations, red tags and shut down of operations (OAC 165:10-7-7).

(15) Scheduled monetary fines (OAC 165:10-7-9).

(16) Use of noncommercial pits (OAC 165:10-7-16).

(17) Surface discharge of fluids (OAC 165:10-7-17).

(18) Discharge to surface waters (OAC 165:10-7-18).

(19) One-time land application of water-based fluids from earthen pits and tanks (OAC 165:10-7-19).

(20) Noncommercial disposal or enhanced recovery well pits used for temporary storage of saltwater (OAC 165:10-7-20).

(21) Waste management practices reference chart (OAC 165:10-7-24).

(22) One-time land application of contaminated soils and petroleum hydrocarbon based drill cuttings (OAC 165:10-7-26).

(23) Application of fresh water drill cuttings by County Commissioners (OAC 165:10-7-28).

(24) Application of freshwater drill cuttings by oil and gas operators (OAC 165:10-7-29).

(25) Application to reclaim and/or recycle produced water for surface activities related to drilling, completion, workover, and production operations from oil and gas wells (OAC 165:10-7-32).

(26) Use of commercial pits (OAC 165:10-9-1).

(27) Commercial soil farming (OAC 165:10-9-2).

(28) Commercial recycling facilities (OAC 165:10-9-4).

(29) Duty to plug and abandon (OAC 165:10-11-3).

(30) Notification and witnessing of plugging (OAC 165:10-11-4).

(31) Plugging and plugging back procedures (OAC 165:10-11-6).

(32) Plugging record (OAC 165:10-11-7).

(33) Review of environmental permit applications (OAC 165:5-1-15 through OAC 165:5-1-19)

(34) Response to citizen environmental complaints (OAC 165:5-1-25 through OAC 165: 5-1-30).

(35) Contempt (OAC 165:5-19-1 through OAC 165:5-19-2).

165:10-3-15. Venting and flaring

(d) Temporary permit exemption for gas vented or flared during initial flowback from a newly completed or recompleted well. Gas vented or flared during initial flowback from a newly completed or recompleted well shall be exempt from the permit requirements of subsection (c) for a period not to exceed 14 days, commencing with the first date gas flow is in excess of 50 mcf/d, if:

(1) Combustible gas flow greater than 50 mcf/d is flared;

(2) Gas with H2S content in excess of 100 ppm is flared;

(3) The operator gives at least 48 hours notice by electronic mail or facsimile to the appropriate Conservation Division District Office or Field Inspector regarding the time when the venting or flaring of gas pursuant to this subsection will begin;

(4) It is not economically feasible to market the gas; and

(5) A suitable stack, stand, or line will be used to prevent a hazard to people or property.

(e) Gas flared after initial flowback from a newly completed or recompleted well. Subsequent to the 14 day initial flowback period addressed in subsection (d), gas flared during flowback from a newly completed or recompleted well shall be exempt from the permit requirements in subsection (c) for an additional period not to exceed 30 days if:

(1) Gas volumes flared from the well are less than or equal to an average rate of 300 mcf/d over the 30 day period, and one or more of the following conditions applies:

(A) No appropriate takeaway structure exists;

(B) The well is an exploration well; or

(C) The quality of the gas to be flared is not pipeline acceptable.

(2) Gas with H2S content in excess of 100 ppm must be flared.

(3) A suitable stack, stand, or line must be used to prevent a hazard to people or property.

(4) The well operator is required to maintain a daily log of gas volumes flared from the well during the 30 day period. The daily log must be preserved for 3 years subsequent to the conclusion of the 30 day period. The log shall be produced upon request by an authorized representative of the Commission.

(5) If gas volumes greater than 300 mcf/d are to be flared during flowback from a newly completed or recompleted well subsequent to the initial 14 day period addressed in subsection (d), then the operator is required to obtain a permit as provided in subsection (c).

(f) Application for an order permitting venting or flaring.

(1) If the Conservation Division denies a Form 1022 application for a well, the operator of a well may apply for an order permitting venting or flaring of gas.

(2) The application and notice shall be in accordance with OAC 165:5-7.

(3) Upon application, notice, and hearing, the Commission may grant or deny an application made pursuant to OAC 165:5-7.

165:10-3-17. Well site and surface facilities

(i) Man-ways on frac tanks. Each frac tank used at the wellsite shall have protective man-ways to prevent persons from accidentally falling into the frac tank.

9.1.19 South Dakota

Regulatory Authority: South Dakota Department of Environment and Natural Resources

Reference Source: South Dakota Rules, Chapter 74:12:02:19 Hydraulic Fracturing Reporting Requirements

74:12:02:19. Hydraulic fracturing reporting requirements.

If hydraulic fracture stimulation is performed on an oil or gas well, the operator shall post on the FracFocus Chemical Disclosure Registry the following stimulation detail:

(1) Fracture date;

(2) American petroleum institute number;

(3) The operator name, county, and state;

(4) Well name and number, longitude, latitude, longitude/latitude projection, production type, true vertical depth, total water volume, and hydraulic fracturing fluid composition as follows:

(a) Trade name;

(b) Supplier;

(c) Purpose;

(d) Intentionally added ingredients;

(e) Chemical abstract number;

(f) Maximum ingredient concentration in additive; and

(g) Maximum ingredient concentration in hydraulic fracturing fluid.

Trade secret information is not required to be disclosed to the FracFocus Chemical Disclosure Registry.

For the purpose of this section, the term, hydraulic fracturing stimulation, means the pressurized injection of fluids commonly made up of water and chemical additives into a geologic formation for the purposes of fracturing the host geologic formation.

9.1.20 Tennessee

Regulatory Authority: Tennessee Board of Water Quality, Oil and Gas

Reference Source: Rules of the Tennessee Department of Environment and Conservation

0400-52-06-.04 Environmental Protection.

(1) Oil and gas wells shall be drilled and operated in a manner that protects aquifers and surface waters. Wells shall be designed to ensure the environmentally sound, safe production of hydrocarbons by containing them inside the well, isolating the productive formations from fresh water formations, and properly executing fracturing and other stimulation operations. Well design and construction must ensure that no leaks occur through or between casing strings. The fluids produced from the well (oil, water, gas)

(3) The operator shall notify the oil and gas inspector at least 24 hours prior to beginning fracturing or acid treatment activities. The operator shall maintain personnel on-site during fracturing activities, and during the initial flow back period, until such time as the well pressure returns to near pre-fracturing reservoir pressure. Unmanned flowback operations shall be checked routinely.

(4) For fracturing treatments using more than 200,000 gallons of water-based liquids, the operator shall conduct pressure monitoring during the fracturing treatment to monitor for a successful treatment and for protection of the groundwater. Annulus pressure shall be continuously monitored and recorded for all such fracturing treatments. If intermediate casing has been set, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded. Records of pressure monitoring shall be included as part of the well history reporting requirements.

0400-53-01-.03 Report Filing.

The operator shall file a Well History, Work Summary and Completion or Recompletion Report (Form R-WH-1) with the Supervisor within 60 days after completing, recompleting or working over a well pursuant to producing oil and/or gas. Wells shall be considered completed when they are capable of being turned into the tanks and/or gas transmission or gathering lines. Well History information shall include the actual materials and volumes used to fracture, the amounts and concentrations of any additives used, the amount of wastewater generated, and the method of disposal of wastewater, for the purpose of making this information easily available to the public.

1) Required disclosures. In the case of any well fractured using a cumulative total of greater than 200,000 gallons of water-based liquids, the following shall apply:

(a) Vendor and service provider disclosures. Service providers who perform any part of a hydraulic fracture using greater than 200,000 gallons of water based liquids and vendors who provide hydraulic fracturing additives directly to the operator for such a hydraulic fracture shall, with the exception of information claimed to be a trade secret, furnish the operator with the information required by subparagraph (b) of this paragraph., as applicable. Such vendors and service providers shall provide this information as soon as possible within 30 days following the conclusion of the fracturing activity and in no case later than 90 days after the commencement of the fracturing activity.

(b) Operator disclosures. Within 60 days following the conclusion of a hydraulic fracture using greater than 200,000 gallons of water-based liquids, and in no case later than 120 days after the commencement of such hydraulic fracturing activity, the operator of the well shall complete the chemical disclosure registry form and post the form on the chemical disclosure registry, including:

1. the operator name;

2. the date of the hydraulic fracture;

3. the county in which the well is located;

4. the API number for the well;

5. the well name and number;

6. the longitude and latitude of the wellhead;

7. the true vertical depth of the well;

8. the total volume of water used in the hydraulic fracturing of the well or the type and total volume of the base fluid used in the fracturing, if something other than water;

9. each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief descriptor of the intended use of function of each hydraulic fracturing additive in the hydraulic fracturing fluid;

10. each chemical intentionally added to the base fluid;

11. the maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid; and

12. the chemical abstract service number for each chemical intentionally added to the base fluid, if applicable.

(c) If the vendor, service provider, or operator claim that the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical is/are claimed to be a trade secret, the operator of the well shall so indicate on the chemical disclosure registry form and, as applicable, the vendor, service provider, or operator shall submit to the Supervisor a Claim of Entitlement Form notifying the Supervisor that the specific identity of a chemical, the concentration of a chemical, or both is being withheld as a trade secret. The operator shall nonetheless disclose all information required under subparagraph (b) of this rule that is not claimed to be a trade secret. If a chemical is claimed to be a trade secret, the operator shall also include in the chemical registry form the chemical family or other similar descriptor associated with such chemical.

(d) Unless the information is entitled to protection as a trade secret, information submitted to the supervisor or posted to the chemical disclosure registry is public information.

(e) Inaccuracies in information. A vendor is not responsible for any inaccuracy in information that is provided to the vendor by a third party manufacturer of the hydraulic fracturing additives. A service provider is not responsible for any inaccuracy in information that is provided to the service provider by the vendor. An operator is not responsible for any inaccuracy in information provided to the operator by the vendor or service provider.

(f) Disclosure to health professionals. Vendors, service companies, and operators shall identify the specific identity and amount of any chemicals claimed to be a trade secret to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a confidentiality agreement. The written statement of need shall be a statement that the health professional has a reasonable basis to believe that (1) the information is needed for purposes of diagnosis or treatment of an individual, (2) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (3) knowledge of the information will assist in such diagnosis or treatment. The confidentiality agreement shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the specific identity and amount of any chemicals claimed to be a trade secret are necessary for emergency treatment, the vendor, service provider, or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgment by the health professional that such information shall not be used for purposes other than the health needs asserted and that that health professional shall otherwise maintain the information as confidential. The vendor, service provider, or operator, as applicable may request a written statement of need, and a confidentiality agreement from all health professionals to whom information regarding the specific identity and amount of any chemicals claimed to be a trade secret was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall in no way be construed as publicly available.

(2) Disclosures not required. A vendor, service provider, or operator is not required to:

(a) disclose chemicals that are not disclosed to it by the manufacturer, vendor, or service provider;

(b) disclose chemicals that were not intentionally added to the hydraulic fracturing fluid; or

(c) disclose chemicals that occur incidentally or are otherwise unintentionally present in the trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid.

(3) Trade secret protection. Vendors, service companies, and operators are not required to disclose trade secrets to the chemical disclosure registry or in the Well History Report. If the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical are claimed to be entitled to protection as a trade secret, the vendor, service provider or operator may withhold the specific identity, the concentration, or both the specific identity and concentration of the chemical, as the case may be, from the information provided to the chemical disclosure registry or in the Well History Report, in the manner provided by paragraph (1) of this rule.

(a) The vendors, service providers, or operators, as applicable, shall provide the specific identity of a chemical, the concentration of a chemical, or both of a chemical claimed to be a trade secret to the Board upon request from the Supervisor stating that such information is necessary to respond to a spill or release or a complaint from a person who may have been directly and adversely affected or aggrieved by such spill or release. Upon receipt of a written statement of necessity, such information shall be disclosed by the vendor, service provider, or operator, as applicable, directly to the Supervisor or his or her designee and shall in no way be construed as publicly available.

(b) The Supervisor or designee may disclose information regarding the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to additional Department of Environment and Conservation staff members to the extent that such disclosure is necessary to allow the Board staff member receiving the information to assist in responding to the spill, release, or complaint, provided that such individuals shall not disseminate the information further. In addition, the Supervisor may disclose such information to any Board Member, the relevant county public health director or emergency manager, or to the Tennessee Department of Public Health or the Tennessee Department of Environment and Conservation Director's upon request by that individual. Any information so disclosed to the Supervisor, a Department staff member, a Board Member, a county public health director or emergency manager, or to the Tennessee Department of Public Health or the Tennessee Department of Environment and Conservation Director's shall at all times be considered confidential and shall not be construed as publicly available. The Tennessee Department of Public Health and the Tennessee Department of Environment and Conservation Department's Directors, or his or her designee, may disclose such information to their respective staff members under the same terms and conditions as apply to the Supervisor.

(4) Any party who is adversely affected by a claim of trade secret that the party believes to be improper may file an action for damages pursuant to T.C.A. § 60-1-403 or for injunctive relief pursuant to T.C.A. § 47- 25-1703(c).

0400-54-01-.12 Disposal of Salt Water.

(1) Underground injection is the preferred form of disposal of salt water, provided, however, that such injection is permitted by appropriate State and Federal agencies.

(2) Produced salt water may either be injected into a subsurface formation(s) productive of hydrocarbons, if part of an approved secondary recovery project, into a subsurface formation(s) not productive of hydrocarbons, if through an approved salt water disposal well, or else may be transported off-lease to an authorized salt water disposal facility if prior approval has been granted by the Department.

(3) Produced salt water shall not be put in any unlined pit, pond, lake or depression, or in any other place in a manner that shall constitute a pollution hazard to the waters of the State including ground water.

(4) No salt water or fracturing liquids shall be discharged to or disposed of at the land surface where they can enter surface water or ground water, unless such discharge is permitted by appropriate State and Federal agencies. Salt water or fracturing liquids discharged to and temporarily stored in lined pits shall be removed before they can leak into underground water.

(5) All pits or ditches used for temporary storage or transport of salt water shall be lined with an impermeable man-made liner in accordance with the liner requirements specified in subparagraph (2)(g) of Rule 0400- 53-03-.02.

9.1.21 Texas

Regulatory Authority: Texas Railroad Commission

Reference Source: Texas Administrative Code, Title 16. Economic Regulation

Chapter 3. Oil and Gas Division

RULE §3.29 Hydraulic Fracturing Chemical Disclosure Requirements

(c) Required disclosures.

(1) Supplier and service company disclosures.

(A) As soon as possible, but not later than 15 days following the completion of hydraulic fracturing treatment(s) on a well, the supplier or the service company must provide to the operator of the well the following information concerning each chemical ingredient intentionally added to the hydraulic fracturing fluid:

(i) each additive used in the hydraulic fracturing fluid and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment;

(ii) each chemical ingredient subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2);

(iii) all other chemical ingredients not submitted under subparagraph (A) of this paragraph that were intentionally included in, and used for the purpose of creating, hydraulic fracturing treatment(s) for the well;

(iv) the actual or maximum concentration of each chemical ingredient listed under clause (i) or clause (ii) of this subparagraph in percent by mass; and

(v) the CAS number for each chemical ingredient, if applicable.

(B) The supplier or service company must provide the operator of the well a written statement that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) of the operator's well is claimed to be entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552. If the chemical ingredient name and/or CAS number is claimed as trade secret information, the supplier or service company making the claim must provide:

(i) the supplier's or service company's contact information, including the name, authorized representative, mailing address, and telephone number; and

(ii) the chemical family, unless providing the chemical family would disclose information protected as a trade secret.

(2) Operator disclosures.

(A) On or before the date the well completion report for a well on which hydraulic fracturing treatment(s) was/were conducted is submitted to the Commission in accordance with §3.16(b) of this title, the operator of the well must complete the Chemical Disclosure Registry form and upload the form on the Chemical Disclosure Registry, including:

(i) the operator name;

(ii) the date of completion of the hydraulic fracturing treatment(s);

(iii) the county in which the well is located;

(iv) the API number for the well;

(v) the well name and number;

(vi) the longitude and latitude of the wellhead;

(vii) the total vertical depth of the well;

(viii) the total volume of water used in the hydraulic fracturing treatment(s) of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment(s), if something other than water;

(ix) each additive used in the hydraulic fracturing treatments and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment(s);

(x) each chemical ingredient used in the hydraulic fracturing treatment(s) of the well that is subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), as provided by the chemical supplier or service company or by the operator, if the operator provides its own chemical ingredients;

(xi) the actual or maximum concentration of each chemical ingredient listed under clause (x) of this subparagraph in percent by mass;

(xii) the CAS number for each chemical ingredient listed, if applicable; and

(xiii) a supplemental list of all chemicals and their respective CAS numbers, not subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), that were intentionally included in and used for the purpose of creating the hydraulic fracturing treatments for the well.

(B) If the Chemical Disclosure Registry known as FracFocus is temporarily inoperable, the operator of a well on which hydraulic fracturing treatment(s) were performed must supply the Commission with the required information with the well completion report and must upload the information on the FracFocus Internet website when the website is again operable. If the Chemical Registry known as FracFocus is discontinued or becomes permanently inoperable, the information required by this rule must be filed as an attachment to the completion report for the well, which is posted, along with all attachments, on the Commission's Internet website, until the Commission amends this rule to specify another publicly accessible Internet website.

(C) If the supplier, service company, or operator claim that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) is entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552, the operator of the well must indicate on the Chemical Disclosure Registry form or the supplemental list that the additive or chemical ingredient is claimed to be entitled to trade secret protection. If a chemical ingredient name and/or CAS number is claimed to be entitled to trade secret protection, the chemical family or other similar description associated with such chemical ingredient must be provided. The operator of the well on which the hydraulic fracturing treatment(s) were performed must provide the contact information, including the name, authorized representative, mailing address, and phone number of the business organization claiming entitlement to trade secret protection.

(D) Unless the information is entitled to protection as a trade secret under Texas Government Code, Chapter 552, information submitted to the Commission or uploaded on the Chemical Disclosure Registry is public information.

(3) Inaccuracies in information. A supplier is not responsible for any inaccuracy in information that is provided to the supplier by a third party manufacturer of the additives. A service company is not responsible for any inaccuracy in information that is provided to the service company by the supplier. An operator is not responsible for any inaccuracy in information provided to the operator by the supplier or service company.

(4) Disclosure to health professionals and emergency responders. A supplier, service company or operator may not withhold information related to chemical ingredients used in a hydraulic fracturing treatment, including information identified as a trade secret, from any health professional or emergency responder who needs the information for diagnostic, treatment or other emergency response purposes subject to procedures set forth in 29 Code of Federal Regulations §1910.1200(i). A supplier, service company or operator must provide directly to a

health professional or emergency responder, all information in the person's possession that is required by the health professional or emergency responder, whether or not the information may qualify for trade secret protection under subsection (e) of this section. The person disclosing information to a health professional or emergency responder must include with the disclosure, as soon as circumstances permit, a statement of the health professional's confidentiality obligation. In an emergency situation, the supplier, service company or operator must provide the information immediately upon request to the person who determines that the information is necessary for emergency response or treatment. The disclosures required by this subsection must be made in accordance with the procedures in 29 Code of Federal Regulations §1910.1200(i) with respect to a written statement of need and confidentiality agreements, as applicable.

(d) Disclosures not required. A supplier, service company, or operator is not required to:

(1) disclose ingredients that are not disclosed to it by the manufacturer, supplier, or service company;

(2) disclose ingredients that were not intentionally added to the hydraulic fracturing treatment;

(3) disclose ingredients that occur incidentally or are otherwise unintentionally present which may be present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid; or

(4) identify specific chemical ingredients and/or their CAS numbers that are claimed as entitled to trade secret protection based on the additive in which they are found or provide the concentration of such ingredients, unless the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission.

(e) Trade secret protection.

(1) A supplier, service company, or operator is not required to disclose trade secret information, unless the Office of the Attorney General or a court of proper jurisdiction determines that the information is not entitled to trade secret protection under Texas Government Code, Chapter 552.

(2) If the specific identity and/or CAS number of a chemical ingredient, the concentration of a chemical ingredient, or both the specific identity and/or CAS number and concentration of a chemical ingredient are claimed or have been finally determined to be entitled to protection as a trade secret under Texas Government Code, Chapter 552, the supplier, service company, or operator, as applicable, may withhold the specific identity and/or CAS number, the concentration, or both the specific identity and/or CAS number and concentration, of the chemical ingredient from the information provided to the operator. If the supplier, service company, or operator, as applicable, elects to withhold that information, the supplier, service company, or operator, as applicable, must provide to the operator or the Commission, as applicable, information that:

(A) indicates that the specific identity and/or CAS number of the chemical ingredient, the concentration of the chemical ingredient, or both the specific identity and/or CAS number and concentration of the chemical ingredient are entitled to protection as trade secret information; and

(B) discloses the chemical family associated with the chemical ingredient; or

(C) discloses the properties and effects of the chemical ingredient(s), the identity of which is withheld.

(f) Trade secret challenge.

(1) The following persons may submit a request challenging a claim of entitlement to trade secret protection for any chemical ingredients and/or CAS numbers used in the hydraulic fracturing treatment(s) of a well:

(A) the landowner on whose property the relevant wellhead is located;

(B) the landowner who owns real property adjacent to property described in subparagraph (A) of this paragraph; or

(C) a department or agency of this state with jurisdiction over a matter to which the claimed trade secret information is relevant.

(2) A requestor must certify in writing to the director, over the requestor's signature, to the following:

(A) the requestor's name, address, and daytime phone number;

(B) if the requestor is a landowner, a statement that the requestor is listed on the county appraisal roll as owning the property on which the relevant wellhead is located or is listed on the county appraisal roll as owning property adjacent to the property on which the relevant wellhead is located;

(C) the county in which the wellhead is located; and

(D) the API number or other Railroad Commission of Texas identifying information, such as field name, oil lease name and number, gas identification number, and well number.

(3) A requestor may use the following format to provide the written certification required by paragraph (2) of this subsection:

UNIVERSITY of HOUSTON

Figure: 16 TAC §3.29(f)(3)

REQUEST TO CHALLENGE CLAIM OF ENTITLEMENT
TO TRADE SECRET PROTECTION OF HYDRAULIC FRACTURING
TREATMENT CHEMICAL COMPOSITION

I, _______(name)_________, challenge the claim of entitlement to trade secret protection for portions of the chemicals or other substances used in the hydraulic fracturing treatment of the following well:

Operator name: ________________________________
County name: ________________________________
API number: ________________________________
Field Name: ________________________________
Railroad Commission oil lease name and number: ______________
Railroad Commission gas identification number: ______________
Well Number: ________________________________

The following is to be completed if the requestor is a landowner:

I certify that I am listed on the appraisal roll as owning the property on which the relevant wellhead is located or I am listed on the appraisal roll as owning property adjacent to the property on which the relevant wellhead is located.

Name of requestor: ________________________________
Mailing address of Requestor: ________________________________
____
Phone number of requestor: ________________________________
Email address of requestor (optional): ________________________________

EMAIL ADDRESS: YOU ARE NOT REQUIRED TO PROVIDE AN EMAIL ADDRESS when completing and filing this form. Please be aware that information provided to any governmental body may be subject to disclosure pursuant to the Texas Public Information Act or other applicable federal or state legislation. IF YOU PROVIDE AN EMAIL ADDRESS, YOU AFFIRMATIVELY CONSENT TO THE RELEASE OF THAT EMAIL ADDRESS TO THIRD PARTIES. Other departments within the Railroad Commission also may use the email address you provide to communicate with you.

Signature of Requestor: ________________________________

Date: ________________

(4) A requestor must file a request no later than 24 months from the date the operator filed the well completion report for the well on which the hydraulic fracturing treatment(s) were performed. A landowner who owned the property on which the wellhead is located, or owned adjacent property, on or after the date the operator filed with the Commission the completion

report for the subject well may challenge a claim of entitlement to trade secret protection within that 24-month period only. The Commission will determine whether or not the request has been received within the allowed 24-month period.

(5) If the Commission determines that the request has been received within the allowed 24-month period and the certification is properly completed and signed, the Commission will consider this sufficient for the purpose of forwarding the request to the Office of the Attorney General.

(6) Within 10 business days of receiving a request that complies with paragraph (2) of this subsection, the director must:

(A) submit to Office of the Attorney General, Open Records Division, a request for decision regarding the challenge;

(B) notify the operator of the subject well and the owner of the claimed trade secret information of the submission of the request to the Office of the Attorney General and of the requirement that the owner of the claimed trade secret information submit directly to the Office of Attorney General, Open Records Division, the claimed trade secret information, clearly marked "confidential," submitted under seal; and

(C) inform the owner of the claimed trade secret information of the opportunity to substantiate to the Office of the Attorney General, Open Records Division, its claim of entitlement of trade secret protection, in accordance with Texas Government Code, Chapter 552.

(7) If the Office of the Attorney General determines that the claim of entitlement to trade secret protection is valid under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information shall not be required to disclose the trade secret information, subject to appeal.

(8) The request shall be deemed withdrawn if, prior to the determination of the Office of the Attorney General on the validity of the trade secret claim, the owner of the claimed trade secret information provides confirmation to the Commission and the Office of the Attorney General that the owner of the claimed trade secret information has voluntarily provided the information that is the subject of the request to the requestor subject to a claim of trade secret protection, or the requestor submits to the Commission and the Office of the Attorney General a written notice withdrawing the request.

(9) A final determination by the Office of the Attorney General regarding the challenge to the claim of entitlement of trade secret protection of any withheld information may be appealed within 10 business days to a district court of Travis County pursuant to Texas Government Code, Chapter 552.

(10) If the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the withheld information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information must disclose such information to the requestor as directed by the Office of the Attorney General or a court of proper jurisdiction on appeal.

(g) Trade secret confidentiality. A health professional or emergency responder to whom information is disclosed under subsection (c)(4) of this section must hold the information confidential, except that the health professional or emergency responder may, for diagnostic or treatment purposes, disclose information provided under that subsection to another health professional, emergency responder, or accredited laboratory. A health professional, emergency responder, or accredited laboratory to which information is disclosed by another health professional or emergency responder under this subsection must hold the information confidential and the disclosing health professional or emergency responder must include with the disclosure, or in a medical emergency, as soon as circumstances permit, a statement of the recipient's confidentiality obligation pursuant to this subsection.

(h) Penalties. A violation of this section may subject a person to any penalty or remedy specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the Commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) (Rule 73) for violation of this section.

RULE §3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements

(B) Zone of critical cement—

(i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(ii) For intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or top of the highest proposed productive zone, whichever is less.

(C) Protection depth—Depth to which usable-quality water must be protected, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(7) Additional requirements for wells on which hydraulic fracturing treatments will be conducted.

(A) All casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or fracture tubing may be subjected.

(B) The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. A surface pressure loss of greater than 10 percent of the initial test pressure is considered a failed test. The casing required to be pressure tested shall be from the wellhead to at least the depth of the top of cement behind the casing being tested. The district director shall be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(C) During hydraulic fracturing treatment operations, the operator shall monitor all annuli. The operator shall immediately suspend hydraulic fracturing treatment operations if the pressures deviates above those anticipated increases caused by pressure or thermal transfer and shall notify the appropriate district director within 24 hours of such deviation. Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director:

> (i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).

(ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.

(iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

> (I) successfully set, cemented, and tested the casing for which the exemption is requested in at least five minimum separation wells by the same operator in the same operating field;

(II) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results or other tests demonstrating that successful cement placement was achieved to isolate productive zones, potential flow zones, and/or zones with corrosive formation fluids; and

(III) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the five wells that have had successful cement jobs.

9.1.22 Utah

Regulatory Authority: Utah Division of Oil, Gas and Mining

Reference Source: R649. Natural Resources; Oil, Gas and Mining; Oil and Gas.

R649-3-39. Hydraulic Fracturing.

1. Chemical disclosure.

1.1. The amount and type of chemicals used in a hydraulic fracturing operation shall be reported to www.fracfocus.org within 60 days of hydraulic fracturing completion for public disclosure.

9.1.23 West Virginia

Regulatory Authority: West Virginia Department of Environmental Protection

Reference Source: Title 35. Legislative Rule, Series 8. Rules Governing Horizontal Well Development

§35-8-5. Perm its, Notice, Review.

5.6. Water Management Plan

5.6.a. All applications for well work permits shall include an estimation of the volume of water that will be used in conjunction with drilling, fracturing or stimulating the well for which the permit is sought and, if the drilling, fracturing or stimulating of the well requires the use of water obtained by withdrawals from waters of this State in amounts that exceed two hundred ten thousand (210,000) gallons during any thirty-day period, the application for a well work permit shall include a water management plan. 1 The water management plan is considered a condition of the permit, and it is enforceable as such.

5.6.b. The water management plan, which may be submitted either on an individual well basis or on a watershed basis, shall include the following information:

5.6.b.1 . The type of water source, such as surface or ground water, the county in which each water source to be used for water withdrawals is located, and the latitude and longitude of each anticipated withdrawal location;

5.6.b.2. The anticipated volume of each water withdrawal;

5.6.b.3. The anticipated months when water withdrawals will be made;

5.6.b.4. The planned management and disposition of wastewater from fracturing, stimulation, and production activities;

5.6.b.5. A listing of the anticipated chemical additives, including Chemical Abstract Service (CAS) registry numbers, that may be used in the hydraulic fracturing or stimulating of the well, and, upon well completion, a listing of the chemical additives, including CAS registry numbers, that were actually used in the hydraulic fracturing or stimulating of the well shall be submitted as part of the completion report required by W. Va. Code § 22-6A-5(a)(14) and section 10 below;

5.7. Well Site Safety Plan

5.7.a. All applications for well work permits shall be accompanied by a well site safety plan to address proper safety measures to be employed for the protection of persons on the well site, as well as the general public in the area surrounding the well site. Each plan shall be specific to the well site described in the permit application and include the surrounding area. The plan shall encompass all aspects of the operation, including the actual well work for which the permit is sought, the anticipated MSDS for the chemical components added to the hydraulic fracturing fluid, and completion, production, and work-over activities. It shall be made available on the well site during all phases of the operation and provide an emergency point of contact and twenty-four (24)-hour contact information for the well operator. At least seven (7) days before commencement of well work or site preparation work that involves any disturbance of the land, the well operator shall provide a copy of the well site safety plan to the local emergency planning committee (LEPC) for the emergency planning district in which the well work will occur or to the county office of emergency services. The operator shall also provide one copy of the Well Site Safety Plan to the surface owner, any water purveyor and any surface owner subject to notice and water testing as provided in section 15 of this rule: Provided, That in the event the Well Site Safety Plan previously provided to a surface owner, water purveyor or surface owner, is later amended, in whole or in part, the operator shall provide a copy of the amendments to the surface owner, water purveyor or surface owner. The operator should work closely with the local first responders to familiarize them with potential incidents that are related to oil and gas development, so that the local first responders have the information they need to provide the support necessary for the operator to implement the well site safety plan. The well site safety plan shall include, at a minimum, the information contained in subdivision 5.7.b. through 5.7.h.

§35-8-9. Operational Criteria

9.1. Water Quality and Quantity Protection Standards

9.1.b.3. For all water used for hydraulic fracturing of horizontal wells and for flowback water from hydraulic fracturing activities and produced water from production activities from horizontal wells, an operator shall comply with the following record-keeping and reporting requirements:

9.1.b.3.A. For production activities, the following information shall be recorded and retained by the well operator: (1) the quantity of flowback water from hydraulic fracturing of the well; (2) the quantity of produced water from the well; and (3) the method of management or disposal of the flowback and produced water; For the purposes of this section flowback shall be defined as the water recovered during the first thirty (30) days of the flowback period.

9.1.b.3.B. For transportation activities, the following information shall be recorded and: maintained by the operator: (1) the quantity of water transported; (2) the collection and delivery or disposal location(s) of the water; and (3) the name of the water hauling company.

9.1.b.3.C. The information maintained pursuant to this subdivision shall be available for inspection by the department along with other required permits and records and maintained for three years after the water withdrawal activity.

9.1.24 Wyoming

Regulatory Authority: Wyoming Oil and Gas Conservation Commission

Reference Source: Wyoming State Rules, Chapter 3. Operational Rules, Drilling Rules

Section 45. Well Stimulation.

(a) An approved Application for Permit to Drill (APD, Form 1) or an approved Sundry Notice (Form 4) is required prior to the initiation of any well stimulation activity. Additional stimulation fluid information shall be provided to the Commission as an addendum to the APD (Form 1), or as part of a comprehensive drilling/completion/recompletion plan, or on a Sundry Notice (Form 4). A federal fieldwide development document or similar document may be accepted by the Supervisor. The Supervisor may require, prior to the well stimulation, the Owner or Operator to perform a suitable mechanical integrity test of the casing or of the casing- tubing annulus or other mechanical integrity test methods using procedures set forth in Chapter 2, Section 6 and Chapter 4, Section 7(e)(i).

(b) Where multiple stimulation activities will be undertaken for several wells proposed to be drilled to the same zone(s) within an area of geologic similarity, approval may be sought from the Supervisor to accept a comprehensive master drilling/completion/recompletion plan containing the information required. The approved master drilling/completion/recompletion plan will then be referenced on each individual well's Application for Permit to Drill (Form 1).

(c) The Owner or Operator shall provide geological names, geological description and depth of the formation into which well stimulation fluids are to be injected.

(d) The Owner or Operator shall provide detailed information to the Supervisor as to the base stimulation fluid source. The Owner or Operator or service company shall provide to the Supervisor, for each stage of the well stimulation program, the chemical additives, compounds and concentrations or rates proposed to be mixed and injected, including:

(i) Stimulation fluid identified by additive type (such as but not limited to acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant);

(ii) The chemical compound name and Chemical Abstracts Service (CAS) number shall be identified (such as the additive biocide is glutaraldehyde, or the additive breaker is aluminum persulfate, or the proppant is silica or quartz sand, and so on for each additive used);

(iii) The proposed rate or concentration for each additive shall be provided (such as gel as pounds per thousand gallons, or biocide at gallons per thousand gallons, or proppant at pounds per gallon, or expressed as percent by weight or percent by volume, or parts per million, or parts per billion);

(iv) The Owner or Operator or service company may also provide a copy of the contractor's proposed well stimulation program design including the above detail;

(v) The Supervisor may request additional information under this subsection prior to the approval of the Application for Permit to Drill (Form 1) or of the Sundry Notice (Form 4);

(vi) The Supervisor retains discretion to request from the Owner or Operator and/or the service company, the formulary disclosure for the chemical compounds used in the well stimulation(s).

(e) The Owner or Operator shall provide a detailed description of the proposed well stimulation design, which shall include:

(i) The anticipated surface treating pressure range;

(ii) The maximum injection treating pressure;

(iii) The estimated or calculated fracture length and fracture height.

(f) Upon prior request via Application for Permit to Drill (Form 1), and/or a comprehensive drilling/completion/recompletion plan, or by Well Completion Report (Form 3), or by Sundry Notice (Form 4), and/or by written letter to the Supervisor justifying and documenting the nature and extent of the proprietary information, confidentiality protection shall be provided consistent with WYO. STAT. ANN. § 16-4- 203(d)(v) of the Wyoming Public Records Act for the following records: “trade secrets, privileged information and confidential commercial, financial, geological or geophysical data furnished by or obtained from any person.”

(g) The injection of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates, into groundwater is prohibited. The proposed use of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates for well stimulation into hydrocarbon bearing zones is authorized with prior approval of the Supervisor. It is accepted practice to use produced water that may contain small amounts of naturally occurring petroleum distillates as well stimulation fluid in hydrocarbon bearing zones

(h) The Owner or Operator or service company shall provide the Supervisor, on a Well Completion or Recompletion Log (Form 3), or on a Sundry Notice (Form 4) for an existing well, the following post well stimulation detail:

(i) The actual total well stimulation treatment volume pumped;

(ii) Detail as to each fluid stage pumped, including actual volume by fluid stage, proppant rate or concentration, actual chemical additive name, type, concentration or rate, and amounts;

(iii) The actual surface pressure and rate at the end of each fluid stage and the actual flush volume, rate and final pump pressure;

(iv) The instantaneous shut-in pressure, and the actual 15- minute and 30-minute shut-in pressures when these pressure measurements are available;

(v) In lieu of (i) through (iv) above, Owner or Operator shall submit the actual well stimulation service contractor’s job log, without any cost/pricing data from the field ticket, or an Owner or Operator representative’s well treatment job log or any report providing the above required information. If information on the actual field ticket describes the Owner’s or Operator’s proprietary completion design and/or well stimulation design, confidentiality may be afforded per subsection (f) above.

(i) During the well stimulation operation, the Owner or Operator shall monitor and record the annulus pressure at the bradenhead. If intermediate casing has been set on the well being stimulated, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded. A continuous record of the annulus pressure during the well stimulation shall be submitted on Well Completion or Recompletion Log (Form 3) or on a Sundry Notice (Form 4).

(i) If during the stimulation, the annulus pressure increases by more than five hundred (500) pounds per square inch gauge (psig) as compared to the pressure immediately preceding the stimulation, the Owner or Operator shall verbally notify the Supervisor as soon as practicable but no later than twenty-four (24) hours following the incident. The Owner or Operator shall include a report containing all details pertaining to the incident, including corrective actions taken, as an attachment to the Well Completion Report (Form 3).

(j) The Owner or Operator shall provide information to the Supervisor on Well Completion Report (Form 3) or on Sundry Notice (Form 4) as to the amounts, handling, and if necessary, disposal at an identified appropriate disposal facility, or reuse of the well stimulation fluid load recovered during flow back, swabbing, and/or recovery from production facility vessels. Storage of such fluid shall be protective of groundwater as demonstrated by the use of either tanks or lined pits. If lined pits are utilized to store fluid for use in well stimulation, or for reconditioning, for reuse, or to hold for appropriate disposal, then the requirements of Chapter 4, Section 1 of these rules shall be met to protect wildlife and migratory birds.

9.2 APPENDIX B – Group 2: Non-Hydrocarbon-Producing, US States with Well Stimulation-Specific Rules

9.2.1 North Carolina

Regulatory Authority: Division of Energy, Mineral, and Land Resources

Reference Source: SUBCHAPTER 05H – OIL AND GAS CONSERVATION

Note: North Carolina is the only non-hydrocarbon producing state that has stimulation-specific rules.

15A NCAC 05H .1624 WELL STIMULATION REPORT

(a) Within 30 calendar days after the conclusion of stimulation operations on an oil or gas well, the permittee shall submit Form 18 – Well Stimulation Report to the Department that includes the following information:

(1) the permittee's name, address, telephone number, fax number, and email address;

(2) the county and nearest city or town where the oil or gas well is located;

(3) the property street address, or nearest address to the ingress and egress point leading from a public road to the well pad;

(4) the API number, the lease name, and the oil or gas well name and number;

(5) the type of oil or gas well;

(6) the total volume of the base fluid;

(7) the total volume of reused water, alternative water, freshwater, or other base fluid that was used in each hydraulic fracturing stage;

(8) the maximum pump pressure measured at the surface during each stage of the hydraulic fracturing operations;

(9) the types and volumes of the well stimulation fluid and proppant used for each stage of the well stimulation operations;

(10) the well stimulation treatment data collected in accordance Rule .1613 of this Section;

(11) for hydraulic fracture stimulations, the estimated maximum fracture height and length and estimated true vertical depth to the top of the fracture achieved during well stimulation treatments as determined by a three dimensional model using true treating pressures and other data collected during the hydraulic fracturing treatments;

(12) the well shooting or perforation record detailing the true vertical and measured depths, and total number of shots in the wellbore;

(13) the wellbore diagram that includes casing and cement data, perforations, and a stimulation summary;

(14) the initial oil or gas well test information recording daily gas, oil, and water rate, and tubing and casing pressure in accordance with Rule .2201 of this Subchapter;

(15) the initial gas analysis, performed by a laboratory certified by the State in accordance with 15A NCAC 02H .0800, which is incorporated by reference including subsequent amendments and editions; and

(16) the engines used on-site during exploration and development, including:

(A) the number of engines with capacities (maximum site-rated horsepower) less than 750 horsepower by engine type, such as compression ignition, two stroke lean burn ignition, four stroke lean burn ignition, rich burn spark ignition;

(B) the number of engines with capacities (maximum site-rated horsepower) greater than or equal to 750 horsepower by engine type, such as compression ignition, two stroke lean burn ignition, four stroke lean burn ignition, rich burn spark ignition; and

(C) the average number of hours of operation for engines in each of the categories above.

(b) The permittee may attach to the completed Form 18 – Well Stimulation Report any information received from a service company regarding the well stimulation operations, as used in the normal course of business, to satisfy some or all of the requirements in this Rule.

15A NCAC 05H .1604 PROHIBITED SUBSTANCES

(a) The Commission incorporates by reference, including subsequent amendments and editions, the "Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels – Draft: Underground Injection Control Program Guidance #84," published by the United States Environmental Protection Agency. Copies of this document may be obtained online for no charge at: http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/epa816r14001.pdf.

(b) Any substance identified by one or more of the following Chemical Abstract Service Registry Numbers listed in the United States Environmental Protection Agency's "Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels" shall not be used in the subsurface: (1) 68334-30-5, Primary Name: Fuels, diesel; (2) 68476-34-6, Primary Name: Fuels, diesel, Number 2; (3) 68476-30-2, Primary Name: Fuel oil Number 2; (4) 68476-31-3, Primary Name: Fuel oil, Number 4; and (5) 8008-20-6, Primary Name: Kerosene.

(c) Drilling fluids and hydraulic fracturing fluids shall not be formulated to include benzene, toluene, ethylbenzene, or xylene.

15A NCAC 05H .1613 WELL STIMULATION REQUIREMENTS

(a) The applicant or permittee shall indicate on the Form 2 – Oil or Gas Well Permit Application the intent to perform well stimulation operations. If well stimulation was not approved as part of the initial application, the permittee desiring to perform such operations shall submit for approval the information required by this Rule via email, fax or mail to the Department for review at least 30 calendar days prior to commencement of planned well stimulation operations.

(b) The production casing shall withstand the maximum anticipated treating pressure of the proposed well stimulation operations. The maximum anticipated treating pressure shall not exceed 80 percent of the minimum internal yield pressure for such production casing.

(c) Non-cemented portions of the oil or gas well shall be tested prior to well stimulation operations to ensure that the wellbore can meet one of the following conditions:

(1) 70 percent of the lowest activating pressure for pressure actuated sleeve completions; or

(2) 70 percent of formation integrity for open-hole completions, as determined by a formation integrity test (FIT).

(d) The permittee shall notify the Department via telephone or email a minimum of 48 hours prior to the commencement of all well stimulation operations at the oil or gas well. The contact information is set forth in Rule .0201 of this Subchapter. The permittee shall submit Form 11 – Required Notifications to the Department, by mail, email, or fax within five calendar days of the telephone or email notice and shall include the following information:

(1) the permittee's name, address, telephone number, fax number, and email address;

(2) the county and nearest city or town where the oil or gas well is located;

(3) the property street address, or nearest address to the ingress and egress point leading from a public road to the well pad;

(4) the API number, the lease name, and the oil or gas well name and number; and

(5) the scheduled date and approximate time for the well stimulation operations.

(e) The permittee shall monitor and record all casing annuli via pressure gauges and by visual discharge for any pressure or flow increases or discharges that would be indicative of a potential loss of wellbore integrity during the well stimulation operations. The permittee shall take remedial action to avoid the loss of wellbore integrity and shall notify the Department within 24 hours of discovery via telephone or email.

(f) If well stimulation treatment design does not allow the surface casing annulus to be open to atmospheric pressure, then the surface casing pressures shall be monitored with a gauge and pressure relief device. The maximum set pressure on the pressure relief device shall be the lower of:

(1) a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet);

(2) 80 percent of the API rated minimum internal yield for the surface casing; or

(3) 80 percent of the surface casing shoe test pressure, adjusted for fluid density.

The well stimulation treatment shall be terminated if the pressures exceed the limits set in Subparagraphs (f)(1) through (f)(3) of this Rule and the Department shall be notified within 24 hours of the occurrence of an exceeded pressure. Pressures on any casing string other than the surface casing shall not be allowed to exceed 80 percent of the API rated minimum internal yield pressure for such casing string throughout the stimulation treatment. The permittee shall notify the Department within 24 hours via telephone or email if treatment pressure exceeds 80 percent of the API rated minimum internal yield pressure on any casing string other than surface casing.

(g) The permittee shall monitor and record, at all times, the following parameters during well stimulation operations:

(1) surface injection pressure, in pounds per square inch (psi);

(2) fluid injection rate in barrels per minute (BPM);

(3) proppant concentration in pounds per thousand gallons;

(4) fluid pumping rate in BPM;

(5) identities, rates, and concentrations of additives used in accordance with Rule .1702 of this Subchapter; and

(6) all annuli pressures.

(h) Following the notification in Paragraph (f) of this Rule, the Department may require additional documentation or oil or gas well tests to determine if the well stimulation operations potentially endanger any fresh groundwater zones, if the permittee is unable to assess the wellbore integrity. If either the permittee or the Department determines fresh groundwater zones are endangered, the Department shall require the permittee to perform remedial operations to correct any oil or gas well failure.

(i) The Department shall notify the Commission at its next regularly scheduled meeting of any remedial operations conducted pursuant to Paragraph (h) of this Rule.

15A NCAC 05H .1807 TRACER TECHNOLOGY

(a) The Department shall only approve the use of tracer technology for the purposes described in this Rule if the Department determines that the tracer technology can trace well stimulation fluids back to the oil or gas well where the fluid was injected and can be used without chemical or radiological impacts to groundwaters or other adverse impacts to public health, welfare, and the environment.

(b) A permittee shall only use approved tracer technology for the following purposes:

(1) as evidence that well stimulation fluid from a particular oil or gas well caused or contributed to an exceedance of the standards set out in 15A NCAC 02L .0202 or 15A NCAC 02B .0200 detected as a result of water supply testing required under Rule .1803 of this Section; or

(2) to identify well stimulation fluid from a particular oil or gas well as the source of contamination detected as a result of an investigation of water supply conducted under Rule .1804 of this Section.

9.3 APPENDIX C – Group 3: Hydrocarbon-Producing, US States without Well Stimulation-Specific Rules

Some states produce oil and gas and have applicable oil and gas regulations. However, these regulations do not contain any stimulation-specific rules. The states include Florida, Indiana, Michigan, Missouri, New York, Oregon, Pennsylvania, and Virginia. The oil and gas regulations from these eight (8) states will not receive further discussion.

9.4 APPENDIX D – Group 4: Non-Hydrocarbon-Producing, US States without Well Stimulation-Specific Rules

Group 3 contains states that do not produce significant quantities of hydrocarbons yet the states have developed a set of oil and gas regulations. The states include Connecticut, Delaware, Georgia, Hawaii, Idaho, Iowa, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New Jersey, Rhode Island, South Carolina, Vermont, Washington, and Wisconsin. Further, the regulations for these sixteen (17) states contain stimulation-specific rules that are shown in the following sections.

9.5 APPENDIX E – Foreign Countries with Well Stimulation-Specific Rules. European Union Well Stimulation Recommendations

Foreign regulations were acquired for Norway, United Kingdom, and Canada's provinces. Recommendations relative to stimulation from the European Union were also obtained and included in this report.

9.5.1 Norway

Regulatory Authority: Norwegian Petroleum Directorate and the Norwegian Petroleum Industry

Reference Source: D-010 Well integrity in drilling and well operations (Rev. 4, June 2013)

Introduction

This standard defines requirements and guidelines relating to well integrity in drilling and well activities. Well integrity is defined to be "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". The standard focuses on establishing well barriers by use of WBE's, their acceptance criteria, their use and monitoring of integrity during their life cycle. The standard also covers well integrity management and personnel competence requirements. The standard does not contain any well or rig equipment specifications.

4.3 Well design

4.3.1 Objective

A well design process shall be carried out for:

a) construction of new wells;

b) alteration, changes or modification to existing wells (i.e. from exploration to production or from producer to injector or vice versa);

c) changes in the well design basis or premises (e.g. life extension, increased pressure exposure , flow media).

All components shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations.

The design process shall cover the complete well or section lifespan encompassing all phases from installation to permanent abandonment and include the effects of material deterioration.

The design basis and design margins shall be known and documented.

Weak-points and operational limits related to design shall be identified and documented.

The well design should be robust, that is:

d) can handle variations and uncertainties in the design basis;

e) can handle changes and failures without leading to critical consequences;

f) can handle foreseeable operating conditions;

g) designed for operations throughout the wells life cycle, including permanent plug and abandonment.

The well design should be subject to a design and operational verification.

4.3.2 Design basis, premises and assumptions

A subsurface well design basis shall be prepared with objectives, premises, functional requirements and assumptions prior to commencement of planning.

The following elements should be assessed and documented in the subsurface well design basis:

a) well objective;

b) design life requirements;

c) restrictions related to drilling location (e.g. seasonal or environmental constraints);

d) well location (location data, seabed conditions);

e) target, TD criteria and tolerances;

f) offset wells;

g) geological depth prognosis with expected stratigraphy and lithology, including uncertainties;

h) temperature, pore pressure and formation stress prognosis for design life of the well, including uncertainties;

i) data acquisition;

j) identification of pressure anomalies due to depletion or nearby injector wells;

k) shallow drilling and location hazards;

l) reservoir data summary;

m) for production wells include potential for scale, wax, sand production, etc.

As an extension to the subsurface well design basis, a drilling and well design basis shall be prepared. The following should be assessed and documented:

n) drilling requirements;

o) summary of reference well data and experience;

p) wellhead and conductor design;

q) casing design;

r) cementing requirements ;

s) drilling fluids;

t) well testing or completion requirements;

u) tubing design;

v) well path listing, with target requirements and proximity calculations to offset wells;

w) sidetrack options;

x) blowout contingency/relief well/capping requirements;

y) plug and abandonment solutions;

z) well studies addressing specific issues; aa) risk analysis.

A design review shall be performed if changes occur that may cause a WBE to exceed its designed and tested operational envelope (e.g., WBE degradation, change in service loads, exposure time, etc.).

4.3.3 Well design pressure

Well design pressure (WOP) is the highest pressure expected at surface/wellhead and shall be established based on the following:

Table 10 – Well design pressure basis.

Well type	Calculation basis for well design pressure
General	As a general rule, the well design pressure shall be based on reservoir pressure minus the hydrostatic pressure of gas plus kill margin, or maximum injection pressure for injection wells.
Exploration well	Use pore/reservoir pressure less the hydrostatic pressure from a column of pressurized methane gas or actual gas composition/gravity from offset wells plus kill margin.
Development well in reservoir with free gas	Use reservoir pressure less hydrostatic pressure from actual gas composition/gravity at virgin reservoir pressure plus kill margin.
Development well in reservoir without free gas	Simulations can be used to determine maximum pressure at shut-in condition based on actual reservoir fluid compositions and gas-oil-ratio plus kill margin. Beware of late life condition with depletion and possible free gas.
Gas lift, injection or stimulated well	If injection pressure is higher than the reservoir generated pressure (as described for development wells) , use the maximum possible generated injection pressure from the topside system to the well, taking into consideration shutdown , PSV settings and PSV response, otherwise use the general rule.

If hydrocarbons cannot be excluded in next section, the section design pressure (SDP) shall be calculated with a gas filled well based on section TD/highest pore pressure and limited to the leak-off pressure at the previous shoe. A kill margin shall be included.

Bullhead kill rates and pressures with seawater and kill fluid should be specified in a kill procedure. Unless kill margin has been specifically calculated, it is recommended to use a minimum 35 bar kill margin. Increase of the kill margin should be considered for exploration and HPHT wells.

Changes in pressures and flow capability, due to injection/production in different reservoir zones nearby or wellbore instability during the lifetime of the field, shall be accounted for in the planning.

4.3.4 Load case scenarios

Static and dynamic load case scenarios for WBEs and critical equipment installed or used in the well shall be established. Design calculations should be performed by skilled personnel, using industry recognized software. Load calculations shall be performed and compared with minimum acceptance criteria/design factors.

Anticipated well movements shall be estimated and assessed (wellhead growth).

4.3.5 Design principles

Design work shall be based on the elastic deformation principle (does not apply to material intended for deformation beyond elastic limits, e.g. expandable components).

Allowable utilization range of a pipe/tubular shall be defined as the common performance envelope area defined by intersections of:

a) the von Mises' Ellipse, and;

b) ISO/TR 10400:2007 or API TR 5C3, 1st edition, December 2008 formulas for burst, collapse and axial stresses, and;

c) pipe end connection capacities.

4.3.6 Design factors

Design factors or other equivalent acceptance criteria shall be established for:

a) burst loads;

b) collapse loads;

c) axial loads;

d) tri-axial loads.

Design factors apply to both pipe body and connections. The calculation of the design factor shall take into consideration all applicable factors influencing the materials performance, with emphasis on wall thickness manufacturing tolerance, corrosion and tubular wear over the lifecycle of the well.

The following design factors shall be used:

Table 11 – Design factors.

Parameter	Design factor*	Supplementary requirement/information
Burst	1,10	
Collapse	1,10	
Axial	1,25	For well testing a design factor of 1,50 should be used to cater for pulling the packer free at the end of the test.
Tri-axial	1,25	Tri-axial design factors are not relevant for connections

5.6 Casing design

5.6.2 Design basis, premises and assumptions

As a minimum the following should be addressed in the design process:

a) planned well trajectory and bending stresses induced by doglegs and hole curvature ;

b) maximum allowable setting depth with regards to kick margin;

c) estimated pore pressure development;

d) estimated formation integrity development;

e) estimated temperature gradient and temperature related effects;

f) drilling fluids and cement program;

g) loads induced by well services and operations ;

h) completion design requirements;

i) estimated casing wear;

j) setting depth restrictions due to formation evaluation requirements;

k) potential for H_2S, $C0_2$;

I) metallurgical considerations;

m) well abandonment requirements;

n) ECO and surge/swab effects due to narrow annulus clearances;

o) isolation of weak formation, potential loss zones, sloughing and caving formations and protection of reservoirs;

p) geo-tectonic forces;

q) relief well feasibility;

r) experience from previous wells in the area or similar wells.

7.6 Completion string design

7.6.1 General

All completion, liner and tie-backs strings shall be designed to withstand all planned and/or expected stresses, including those induced during potential well control situations. The design process shall be for the full life cycle of the well, including abandonment. Degradation of materials shall be taken into consideration. The design basis and margins shall be known and documented.

All components of the completion string including connections shall be subject to load case verification. Weak points shall be identified and documented.

The completion design shall accommodate permanent abandonment.

7.6.2 Design basis, premises and assumptions

The following shall be assessed to establish the dimensioning parameters for the design process:

a) reservoir pressure during well life, including reservoir fluids and/or gas properties;

b) planned well trajectory and bending stresses induced by well doglegs and curvature;

c) casing design;

d) well control and maximum well kill pressure;

e) planned production and/or injection rate and associated fluid and/or gas properties;

f) annulus pressure management of accessible annuli;

g) H2S and/or C02 including potential reservoir souring during life of well;

h) fluids compatibility and corrosion; i) well life expectancy;

j) material selection;

k) sand control requirements;

I) artificial lift requirements;

m) potential hydrate, scale and asphaltene deposits and chemical injection requirements;

n) loads induced by well services and operations including well interventions, scale squeeze, fracturing and/or other chemical treatments;

o) geo-tectonic forces;

p) well suspension and abandonment requirements;

q) experience from previous wells in the area or similar wells.

7.6.3 Load cases

When designing for burst, collapse and axial loads, cases applicable for the planned activity shall be applied. Every well type shall have a tubing stress analysis performed. The following load cases shall be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed:

Table 12 – Load cases.

Item	Description	Comments
1.	Pressure testing of the completion string	
2.	Pressure testing A-annulus	Testing of tubing hanger seals from below and production packer from above (as a minimum to MAASP)
3.	Shut-in of well	
4.	Dynamic flowing and injection conditions	Special focus on temperature effects for production and injection wells (water, gas, WAG and simultaneous WAG)
5.	Injection	Maximum injection system pressure (WOP)
6.	Production	Should check tubing collapse as a function of minimum tubing pressure (plugged perforations/ low test separator pressure/ depleted reservoir pressure) combined with a high operating annulus pressure (minimum to MAASP) Consider effects due to erosion/ corrosion
7.	Bullheading/ pumping	Well killing, stimulation , fracturing
8.	Overpull	Stuck string, shear rating of pins/ rings. Tensile strength

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Item	Description	Comments
		of all completion components, including equipment connections
9.	Firing of TCP guns	
10.	Temperature effects	All closed volumes with special attention to start-up and shut- in of well
11.	Artificial lift	Shut-in of annulus by closing ASV and evacuated annulus above gas lift valve Maximum injection system pressure

7.6.4 Minimum design factors

Tubing shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The minimum design factors shall be as described in section 4.3.6.

7.6.5 Completion equipment - emergency shut-down system

The following completion string equipment shall be classified as part of the installation's emergency shutdown system:

a) DHSV;

b) ASV or other fail-safe closed devices, if installed;

c) tree valves - master and wing valves;

d) tree/wellhead valves serving chemical injection lines;

e) tree/wellhead valves serving annulus gas lift valve.

8.8 Anomalies

The event of a possible loss of a well barrier, deviation from normal or predicted pressure behaviours, or change in fluid compositions that could negatively affect the well barriers, shall trigger an evaluation of the event.

Anomalies shall be evaluated to determine the cause and effects, considering the following:

a) method of normalization of the situation and restoring two well barriers;

b) gas and/or liquid leak rate across the well barrier;

c) ensure the acceptance criteria for qualifying the well barrier is maintained;

d) blowout potential, should the remaining well barrier envelope fail;

e) verification of well design to ensure the present design can manage new load scenarios ; and

f) ensure the operating limits are still valid.

Any further deterioration or additional failure shall not significantly reduce the possibility of containing the hydrocarbon/pressure and normalising the well.

If the well barrier status or monitoring ability is altered, production/injection shall only continue when supported by a risk assessment and MoC process.

When there is a risk of corrosion or erosion occurring, wall thickness loss calculations shall be performed. The need for periodic systematic measurements, such as caliper runs, shall be evaluated. If wall thickness loss exceeds the design criteria, new load calculations shall be performed and/or operational limits re-evaluated.

14 Pumping operations

14.1 General

This section covers requirements and guidelines pertaining to well integrity during pumping (injection) of fluids into a well through tubing and annuli. The duration of the pumping operations might be short term, when performing stimulation, corrosion treatment, scale treatment, energised fluid kick-offs, clean-outs, bullheading, killing or long term, when disposing slurryfied drill cuttings or waste.

Continuous injection of water and gas or other fluids into reservoirs for enhanced oil recovery and reservoir pressure maintenance is covered in Section 8. Cement pumping and injection tests are not included.

The purpose of this section is to describe the establishment of well barriers by use of WBE's and additional requirements and guidelines to execute this activity in a safe manner.

14.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (14.8).

14.3 Well barrier acceptance criteria

If the maximum pumping pressure exceeds the RWP of the tree, or a correspondingly lower pressure if tree pressure rating has been reduced by corrosion or erosion, the tree shall be isolated from the pumping pressure by a tree isolation tool.

Injection shall not be performed into any formation which has the ability to:

a) propagate vertical fractures to the seabed;

b) flow, unless there is a DHSV installed in the tubing or an ASV in the specific annulus used for injection, or if static hydrostatic pressure of the injected fluid column exceeds the pore pressure.

14.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 13 – Additional EAC requirements.

Table	Element name	Additional features, requirements and guidelines
22	Casing cement	Annulus or pipe bore below the injection point should be cemented and/or isolated to avoid injecting into a reservoir that is not intended for injection
33	Surface tree	Remotely actuated tree valves should be isolated from inadvertent closure during pumping operations

14.6 Well design

14.6.1 General

See sections 5 and 7 for well design.

14.6.2 Design basis, premises and assumptions

It shall be verified that all well equipment and surface equipment can withstand the planned loads induced by the pumping operations. Historical operational data for the well shall be reviewed and the equipment pressure rating shall be downgraded based on measured or estimated material loss caused by corrosion, erosion and other factors that may have affected the integrity of the equipment.

14.6.3 Load cases

When designing for burst, collapse and axial load, the following load cases shall minimum be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed.

Table 14 – Load cases.

Item	Description	Comments
1.	Material compatibility verification	Material compatibility with all chemicals and mixtures of these chemicals which will be pumped.
2.	Maximum allowable pumping rate	Assess abrasive erosion from all fluids and its content (sand, gravel etc.) and pressure surge by accidental closure of a valve in the flow conduit when pumping at maximum allowable rate
3.	Maximum differential pressure	During the injection period
4.	Temperature impacts, tubular cooldowns and annular pressure build-up during flowback	During the injection period and until equilibrium is reached

14.6.4 Minimum design factors

Well string/components shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The minimum design factors shall be as described in section 4.3.6.

14.7 Other topics

14.7.1 Pumping through production tubing

The following applies when pumping through production tubing:

a) The pump shall have pressure relief valve to protect against overloads. The relief valve should discharge into a non-hazardous location. The pump shall have an over pressure limit system that automatically stops the pump before overloads occur.

b) The DHSV and HMV should be isolated from inadvertent closure during pumping operations.

c) Neighbour annulus and/or pipes isolated from the injection shall be monitored on a regular basis for pressure build up. The cause of any pressure increase (temperature, pipe expansion or leak) shall be verified.

d) After pumping, all annuli (that can be monitored) shall be monitored regularly until the temperature equilibrium is reached.

14.7.2 Handling and pumping of energised fluids

The following applies when handling or pumping liquefied gases or liquids containing gases:

a) All surface hoses and piping lines used on the low pressure side of the liquefied gas shall be qualified for liquid gas service and the specific gas to be pumped.

b) It should be possible to drain the lowest point of surface hoses and piping lines to minimise the risk of having ice blocks.

c) All equipment used for storing and/or pumping liquefied gases shall be positioned in a bounded area.

d) The bounded area shall:

1) be arranged to collect and contain accidental spills of liquefied gases;

2) provide thermal insulation of deck and construction;

3) have water hoses with fine spray nozzle available.

e) The discharge line should have a one-way check valve and pressure bleed-off arrangement.

f) Rubber hoses should not be used as a part of the high pressure discharge line.

g) The injection pump shall be fitted with a pressure limit switch, which shall be set to 1,1 times the maximum allowable pumping pressure.

14.7.3 Temporary installed surface discharge lines

When temporarily installed surface discharge lines (between the pump that is used for pumping and the first permanent valve on a WBE) are used in conjunction with pumping operations, the following applies:

a) They shall be adequately anchored to prevent whipping, bouncing, or excess vibration, and to constrain all piping if a break should occur.

b) Precautions shall be taken and reviewed with relevant personnel to ensure that they are not damaged by dropped objects from cranes, trolleys, skidding systems etc.

c) Their RWP shall be equal to or exceed the maximum pumping pressure.

d) They shall be leak tested to a pressure exceeding maximum allowable pumping pressure, after installation and prior to use.

e) They should have sufficient ID to avoid erosion from the pumping operation.

f) A check valve shall be installed in each discharge line as close to the well connection point as possible. A bleed-off line between the check valve(s) and the production tree master valve should be installed to enable venting of trapped pressure.

g) They shall be equipped with a pressure relief valve at the pump set and checked for the maximum allowable pumping pressure. The relief valve should discharge into a non-hazardous location. (See subclause 14.7.1 a).)

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15 Well barrier elements acceptance tables

Table 15 – Casing.

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.	
C. Design construction selection	1. Casing/liner strings, including connections shall be designed to withstand all loads and stresses expected during the lifetime of the well (including all planned operations and potential well control situations). Any effects of degradations shall be included. 3. Minimum acceptable design factors shall be calculated for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. All load cases shall be defined and documented with regards to burst, collapse and tension/compression. 4. Casing design can be based on deterministic or probabilistic models. 5. Casing exposed to hydrocarbon flow potential shall have gas-tight threads. Exception: Surface casing which is exposed or can be potentially exposed to normal gradient shallow gas.	ISO 11960 ISO 13679 ISO 10405

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Table 16 – Casing cement.

Features	Acceptance criteria
D. Initial verification	3. Critical casing cement shall be logged and is defined by the following scenarios: a) the production casing/production liner when set into/through a source of inflow with hydrocarbons; b) the production casing/production liner when the same casing cement is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock.

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Table 17 – Tree isolation tool.

Features	Acceptance criteria	See
A. Description	The tree isolation tool is a temporary arrangement installed in the tree to isolate the tree and tubing hanger from treating pressure and fluids.	
B. Function	The function of the tree isolation tool is to: a) isolate the tree and tubing hanger from treating pressure when maximum treating pressures could exceed the maximum rated WP for the tree/tubing hanger; or b) isolate the tree from abrasive fluids.	
C. Design, construction and selection	1. The WP of the tree isolation tool shall as a minimum exceed the maximum treating pressure, plus 10 %. 2. The tree isolation tool shall be flanged to the tree with metal to metal seals. 3. The tree isolation tool re-tract system shall be remote operated. 4. The tree isolation tool shall have double valve system on the fluid inlet. Both valves shall be flanged to the tree isolation tool with metal to metal seals. 5. The inner valve shall be hydraulically remote operated. 6. The seal stack which seals inside the tubing shall have a WP equal to the tree isolation tool in the specific tubing ID it is designed to seal against.	
D. Initial verification	1. It shall be documented that the tree isolation tool has been leak tested to 50 % above the RWP after last inspection. 2. After installation on the tree the tree isolation tool shall be leak tested to tree WP against upper or lower master valve. 3. Stable pressure in annulus between the tree isolation tool and the tree after pressure bled off in the tree.	

Features	Acceptance criteria	See
E. Use	1. Discharge treating line shall have sufficient length such that the tree isolation tool seal stack can be deployed and retracted with two well barriers in place. 2. Wing valve on the tree shall be open after sealing the tree isolation tool seal stack and a bleed line shall be discharged to a non- hazardous location. The seal stack seal should be monitored throughout the operation.	
F. Monitoring	Annulus between the tree isolation tool and the tree shall be continuously monitored for pressure build up indicating leaking seal stack on the tree isolation tool.	
G. Common well barrier	None	

Table 18 – Completion string.

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string is to provide a conduit for formation fluid from the reservoir to surface or vice versa, and prevent communication between the completion string bore and the A-annulus.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have IS013679 CAL III connections or CAL IV connections when exposed to free gas during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to: a) tensile and compression load exposure; b) burst and collapse criteria; c) tool joint clearance and fishing restrictions; d) tubing and annular flow rates; e) abrasive composition of fluids; f) buckling resistance; g) metallurgical composition in relation to exposure to formation or injection fluid;	ISO 11960/API Spec 5CT ISO 13679

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Features	Acceptance criteria	See
	h) Strength reduction due to temperatures effects.	
D. Initial test and verification	Pressure testing to WOP.	
E. Use	None	
F. Monitoring	Pressure integrity is monitored through the annulus pressure.	
G. Common well barrier	None	

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Table 19 – Completion string components.

Features	Acceptance criteria	See
A. Description	These elements consist of a housing with a bore. The completion string component is designed to prevent undesired communication between the completion string bore and the A-annulus.	
B. Function	Its purpose may be to provide support to the functionality of the completion, e.g. gas-lift or side pocket mandrels with valves or dummies , nipple profiles, gauge carriers, control line with seals/connections , etc.	
C. Design, construction and selection	1. The components (pipe and threads) shall have IS013679 CAL Ill connections or CAL IV connections when exposed to free gas during its lifetime. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. The component should be designed/selected with respect to: a) burst and collapse criteria; b) tensile and compression load exposure; c) OD clearance and fishing restrictions; d) tubing (and annular) flow rates, also including erosion effects; e) metallurgical composition in relation to exposure to formation, injection or annulus fluid; f) odd shaped assemblies in casting material shall be subject to finite element analysis; g) Strength reduction due to temperatures effects.	ISO 13679 ISO 14310 ISO 10432/API Spec 14A ISO 10417 API RP 148 API Spec 11V1 ISO 17078-2

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Features	Acceptance criteria	See
	4. Valves in the completion string above the production packer shall be qualified and tested in accordance to the leak criteria given in ISO 14310. V1 for design validation or VO if free gas at depth.	

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9.5.2 United Kingdom

2. Safety and Environmental Management

2.1. Management Systems

To assist in discharging their responsibilities operators and other duty holders should operate in accordance with effective management systems and ensure that personnel are competent in the tasks they are required to do.

Effective risk-based, systematic, management of well integrity, the integrity of the surface equipment used in fracturing/flow-back operations and of other associated operations is critical to ensuring the safety of the well operations and environmental protection.

Operators' management systems should be developed and applied to all operations including any pre-drilling operations such as seismic acquisition work.

In respect of the development of (health and safety) management systems operators should refer to the HSE document "Successful Health and Safety Management". This is the over-arching guide on the essential philosophy of good health and safety: what it means; how to achieve it; and how to maintain it. http://www.hse.gov.uk/pubns/books/hsg65.htm

Operators should also operate in accordance with a suitable environmental management system that conforms to the principles in ISO 14001.

Operators should consider the advantages of adopting a systematic environmental risk assessment and management framework drawing on the "Green Leaves III" guidelines (Cranfield University/Defra, November 2011).

As described in the Oil and Gas UK Well Integrity Guidelines Summary, operators should have developed a system for ensuring well integrity throughout the well life cycle. For well integrity during fracturing/flow-back/testing operations the system should take into account the additional elements described in these guidelines.

Management of operations can be devolved but the responsibility for the integrity of the well and protecting the environment remains with the operator.

Operators should have a management of change (MOC) procedure covering wells and well operations through the full life cycle from initial design to final abandonment. The Oil and Gas UK Well Integrity Guidelines (Section 4.8) contains guidelines on MOC for well operations. A similar MOC procedure should cover changes to fracturing/flow-back/testing and water/fluid transport operations.

3. Disclosure and Transparency

Operators should engage with local communities, residents and other stakeholders at each stage of a development, beginning in advance of any operations and where possible in advance of any application for planning permission. They should provide sufficient opportunity for comment on plans, operations and performance, listen to concerns and respond appropriately and promptly. The emphasis should be on recognising relations with the host community as a key management priority, and having a strategy or plan for engagement which is developed early and which links to any statutory processes. The planning system may provide specific opportunities for open consultation, but operators should also engage more broadly with stakeholders.

Operators need to explain openly and honestly their drilling, fracturing design and operational practices including environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development.

Referring specifically to hydraulic fracturing, operators should measure and disclose operational data on, for example:

• Water use.

• The volumes and characteristics of waste water.

• Produced water disposal methods.

• Fracturing fluid additives (constituents) concentrations and volumes.

• Shale gas volumes including any emissions.

• Fracture design and containment.

• Any induced seismicity.

• Good data, measurement and transparency are vital to public confidence.

For example, effective tracking and documentation of waste water is necessary to demonstrate to stakeholders that good practice is being adopted as well as to record the proper treatment and disposal. Also, public disclosure of the chemicals used in the hydraulic fracturing process and the volumes/constituents/concentrations involved will, in addition to providing sufficient information to regulators, assist the public in understanding the processes involved.

Operators should demonstrate how they intend to minimise disruption to the community during operations, for example any vehicle management and noise reduction measures.

Operators should work towards maximising the economic benefits to local communities from their operations, for example considering local employment and utilising locally-based contractors, where possible.

4. Regulatory Compliance

The following sections summarise the main regulations that concern shale gas well integrity and hydraulic fracturing for each phase of operations. The summary does not cover all the safety-related regulations that apply to operations at well sites (for example the Electricity at Work Regulations or the Working at Height Regulations). Operators should always refer to the regulations themselves for full details and for any relevant Approved Codes of Practice and associated guidance.

Although the well-related regulations, below, are made under the Health and Safety at Work Act, maintaining adequate well integrity is also critical to environmental protection (e.g. groundwater protection) and therefore operators should ensure that well design standards also achieve best environmental practice.

For guidance concerning Petroleum Exploration and Development Licensing (PEDL), including the well consent system, refer to the DECC website at:

http://og.decc.gov.uk/en/olgs/cms/explorationpro/onshore/onshore.aspx.

Shale gas well operators should open an early dialogue with DECC concerning any requirements for submissions in connection with drilling and fracturing operations. It is likely that the 30 day consent Well Operations Notification System (WONS) will need to be preceded by other submissions of information referred to in these guidelines (for example information on Hydraulic Fracturing Programmes – see Section 5.5).

4.1. Well Design and Construction

The Offshore Installations and Wells (Design and Construction Etc) Regulations 1996 (DCR) apply to wells. The main regulations concerning well design and construction (including fracturing operations) are summarised as follows:

DCR Regulation 13 (General duties of Well Operators in connection with wells).

The Well Operator shall ensure that a well is so designed, modified, commissioned, constructed, equipped, operated, maintained, suspended and abandoned that –

a) so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and

b) risks to health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as reasonable practicable.

Section 5 of these guidelines deals with guidance on well design and construction.

DCR Regulation 14 - Assessment of Conditions Below Ground:

1) Before the design of a well is commenced the Well Operator shall cause –

a) the geological strata and formations, and fluids within them, through which it may pass; and

b) any hazards which such strata and formations may contain, to be assessed.

2) The Well Operator shall ensure that account is taken of the assessment required by paragraph (1) when the well is being designed and constructed.

3) The Well Operator shall ensure that while an operation (including the drilling of a well) is carried out in relation to the well, those matters described in sub-paragraphs (a) and of paragraph (1) shall, so far as is reasonably practicable, be kept under review and that, if any change is observed in those matters, such modification is made where appropriate, to –

a) the design and construction of the well; or

b) any procedures, as are necessary to ensure that the purposes described in regulation 13(1) will continue to be fulfilled.

Section 5 of these guidelines deals with the assessment of conditions below ground.

DCR Regulation 16 – Materials

The Well Operator must ensure that every part of a well is composed of material which is suitable for achieving the purposes described in Regulation 13(1). (General Duties).

Section 5 of the DCR Regulation 16 – Materials

The Well Operator must ensure that every part of a well is composed of material which is suitable for achieving the purposes described in Regulation 13(1). (General Duties).

Section 5 of these guidelines deals with well materials.

Regulation 20 – Co-operation

This regulation requires any person involved with a well operation to co-operate with the Well Operator in discharging his duties under Regulation 13(1).

All companies involved in the well design and operations processes (e.g. contractors) need to be aware of this duty to cooperate so that the Well Operator can fulfil his general duties under Regulation 13(1) to prevent unplanned escapes of fluids from a well and ensure the risks from the well are as low as reasonably practicable.ese guidelines deals with well materials.

The BSOR apply to onshore well sites and to wells. The main regulations concerning well design and construction (including fracturing operations) are summarised as follows:

Regulation 9 and Schedule 2(7)

The Borehole Site Operator and other employers must ensure that suitable well control equipment is provided for use during both drilling and fracturing/flow-back operations.

Detailed guidance on well control equipment is provided in the BSOR, Schedule 2(7) guidance.

Section 7.2 of these guidelines deals with surface well control equipment during fracturing and flow-back operations.

BSOR Regulation 9 and Schedule 2(3)

When borehole operations are carried on, there shall be provided a sufficient number of competent persons with a view to enabling those operations to be carried on safely.

Section 5.1 of these guidelines deals with management supervision and competence at the well design and construction phase.

Section 7.3 of these guidelines deals with planning, management supervision and competence during fracturing/flow-back.

4.4. Independent Well Examination

DCR Regulation 18 concerns the provision and implementation of arrangements for independent well examination.

The Well Operator must prepare and put into place arrangements in writing for such examinations, by independent and competent persons, of any part of the well, or similar well, information, or work in progress. The written arrangements are known as the well examination scheme. The scheme describes the independent well examination process.

The Oil and Gas UK Guidelines for Well Operators on Well Examination and the Guidelines for Well Operators on Competency of Well Examiners provide more detailed guidance on the subject of well examination.

Section 5.10 of these guidelines deals with independent well examination in the well design and construction phase. Section 5.11 deals with independent well examination of well abandonment (and well suspension) designs and operations.

Examination of wells during the operations (production) phase will be added at a later issue.

4.5. Borehole Site Safety

The Borehole Sites & Operations Regulations 1995 (BSOR) place duties on operators in connection with general site safety including:

1. The provision of health and safety documents.

2. Risk assessments.

3. Coordination of safety measures.

4. Plans for:

• Provision of escape and rescue.

• Prevention of fires and explosions with particular reference to blowouts and escapes of flammable gas.

• General fire protection.

• Detection and control of toxic gases.

5. Site planning and design.

6. Arrangements for attendance of emergency services and site access.

7. Stability, strength and suitability of workplaces

These guidelines concern shale gas well integrity and fracturing/flow-back operations. They are not intended to cover the above, general, site safety aspects in any detail. Operators should refer to the BSOR Regulations and detailed guidance.

4.6. Fracturing Flow-Back and Well Testing Equipment and Operations

The DCR apply to any fracturing equipment that also forms part of a well.

The BSOR apply to fracturing equipment and operations at the well site.

The Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR) (apart from 3 specified exceptions which are covered by the BSOR) apply to any operations involving dangerous substances (including flammable gases).

- Regulation 5 concerns the requirement to carry out and record suitable and sufficient risk assessments.
- Regulation 6 concerns the elimination or reduction of risks from dangerous substances.
- Regulation 8 concerns arrangements to deal with accidents incidents and emergencies.
- Regulation 9 concerns the provision of information, instruction and training to employees and other people who may be present at the workplace.

Therefore the DSEAR regulations are closely linked to the BSOR in respect of managing the risks associated with flammable gases.

Regulation 4 of the Provision and Use of Work Equipment Regulations 1998 (PUWER) concerns the suitability of fracturing equipment:

1) Every employer shall ensure that work equipment is so constructed or adapted as to be suitable for the purpose for which it is used or provided.

2) In selecting work equipment, every employer shall have regard to the working conditions and to the risks to the health and safety of persons which exist in the premises or undertaking in which that work equipment is to be used and any additional risk posed by the use of that work equipment.

3) Every employer shall ensure that work equipment is used only for operations for which, and under conditions for which, it is suitable.

Regulation 5 of PUWER concerns the maintenance of equipment:

1) Every employer shall ensure that work equipment is maintained in an efficient state, in efficient working order and in good repair.

2) Every employer shall ensure that where any machinery has a maintenance log, the log is kept up to date.

The two parts of regulation 5 outline the general requirements for keeping work equipment and machinery in a condition which does not pose a risk to employees' safety. It highlights the employer's duty to ensure that maintenance logs are kept up to date.

Regulation 6 of PUWER concerns the inspection of equipment:

1) Every employer shall ensure that, where the safety of work equipment depends on the installation conditions, it is inspected –

a) after installation and before being put into service for the first time; or

b) after assembly at a new site or in a new location,

to ensure that it has been installed correctly and is safe to operate.

2) Every employer shall ensure that work equipment exposed to conditions causing deterioration which is liable to result in dangerous situations is inspected –

a) at suitable intervals; and

b) each time that exceptional circumstances which are liable to jeopardise the safety of work equipment have occurred,

to ensure that health and safety conditions are maintained and that any deterioration can be detected and remedied in good time.

3) Every employer shall ensure that the result of an inspection made under this regulation is recorded and kept until the next inspection under this regulation is recorded.

4) Every employer shall ensure that no work equipment –

a) leaves his undertaking; or

b) if obtained from the undertaking of another person, is used in his undertaking unless it is accompanied by physical evidence that the last inspection required to be carried out under this regulation has been carried out.

DCR, BSOR, PUWER and DSEAR compliance issues in relation to fracturing equipment and operations are covered in Section 7.

Although all the regulations referenced in this section are made under the Health and Safety at Work Act, they relate to the prevention and mitigation of environmental releases of fluids and gases from wells and associated surface equipment.

4.8. Waste and Water

Matters concerned with transport, treatment and disposal of waste and protection of water resources are regulated by the Environment Agency (EA) in England and Wales and the Scottish Environment Protection Agency (SEPA) in Scotland. The following makes reference to legislation as applied in England and Wales and in Scotland.

4.8.1. The Water Resources Act 1991

This act makes various provisions in respect of the protection of groundwater in England and Wales. Section 199 requires notice to be given to the EA of an intention to construct or extend a borehole for the purposes of searching for, or the extraction of, minerals.

The EA also requires notification of an intention to extract groundwater and where the operation is likely to extract in excess of 20m3 per day, the operator will require an abstraction license.

4.8.2. The Environmental Permitting Regulations 2010 (England and Wales)

These Regulations were introduced in 2010, replacing the 2007 Regulations. They were amended by the Environmental Permitting Amendment Regulations 2012.

In 2007 the Regulations combined the Pollution Prevention and Control (PPC) and Waste Management Licensing (WML) regulations. Their scope has since been widened to cover controls relevant to shale gas operations, including water discharge and groundwater activities, managing radioactive substances and

Guidance on their application is provided by the Environmental Agency at:

http://www.environment-agency.gov.uk/business/topics/permitting/default.aspx

4.8.3. The Water Environment (Controlled Activities) (Scotland) Regulations 2011.

The Water Environment (Controlled Activities) (Scotland) Regulations 2011 (CAR) regulates activities associated with the water environment.

The regulations cover the construction of boreholes, the abstraction of water and the discharge of pollutants into the water environment.

Guidance on their application is provided by the Scottish Environment Protection Agency at:

http://www.sepa.org.uk/customer_information/energy_industry.aspx

5. Well Design and Construction (Operations Planning)

Relevant Regulations and Guidelines are:

1. DCR Regulations and Guidance.

2. BSOR Regulation 9(1) and Schedule 7. (Well Control Equipment).

3. HSE Semi Permanent Circular (SPC 43) on Well Construction Standards (Section 4).

4. HSE "ALARP at a Glance" Document.

5. Oil and Gas UK Well Integrity Guidelines (Section 5).

6. Oil and Gas UK Guidelines on Competency for Wells Personnel.

7. Relevant industry codes of practice (e.g. ISO and API Codes – listed at Appendix 4).

5.1. Management Supervision and Competence - Wells

Operators should refer to the Oil and Gas UK Guidelines on Competency for Wells Personnel. This guidance is relevant to all employers of personnel working on wells in Great Britain. The guidelines describe the regulations applicable to competency in respect of wells. In addition to these regulations, at onshore well sites, Regulation 9(1) and Schedule 2 of the BSOR require that:

1. A competent person appointed by the operator shall be in charge of every borehole site where employees are present and there shall be sufficient competent persons appointed by the operator to exercise immediate supervision of operations with a view to ensuring the health and safety of persons at work at the site.

2. There shall be provided a sufficient number of competent persons with a view to enabling operations to be carried on safely.

The Oil and Gas UK Guidelines on Competency for Wells Personnel describe the design, development and implementation of suitable Competency Management Systems. Table 1 contains the following listing of the roles that require formal competencies and assessment for onshore wells' personnel positions:

1. Drilling Manager.

2. Drilling Superintendent.

3. Senior Drilling Engineer.

4. Drilling Engineer.

5. Senior Completions Engineer.

6. Completions Engineer.

7. Petroleum Engineer.

8. Rig Manager (including well site manager).

5.2. Risk Identification and Assessment

In addition to the guidance contained in the relevant regulations (BSOR DCR and DSEAR), well-related risk assessment guidelines are provided in the Oil and Gas UK Well Integrity Guidelines, sections 5.1 and 5.2.

The primary responsibility for identifying, assessing and mitigating well hazards rests with the Well Operator.

In respect of shale gas wells, operators should ensure that the following, specific, design and operational risks are considered as part of the well-related risk assessment process:

1) Groundwater isolation (see Section 5.4.3).

2) Fracturing Containment (see Section 5.5).

3) Seismicity induced by hydraulic fracturing (see Section 5.6).

These are not specifically addressed in the Oil and Gas UK Well Integrity Guidelines.

5.3. Well Design and Barrier Planning

Detailed guidance on well design and operations planning, including barrier design and planning is described in Section 5 of the Oil and Gas UK Well Integrity Guidelines.

Section 4 of the Oil and Gas UK Well Integrity Guidelines concerns the selection, installation, testing and maintenance of well barriers.

5.4. Casing and Cementation Design Including Groundwater Isolation

All control measures should be based on well design risk assessments and the environmental risk assessments and these should be documented in the well's basis of design documentation and well operations programme(s) (or equivalent document names).

Section 8 deals with environmental management.

5.4.1. Casing Design

Section 5.4 of the Oil and Gas UK Well Integrity Guidelines concerns casing design. Section 5.9 refers to designing a well for the eventual suspension and abandonment including references to permeable horizons outside the casing. Section 6.6 concerns the installation and testing of barriers (including casing and cement).

Section 6.2 of the Oil and Gas UK Suspension and Abandonment Guidelines contains guidance on casing annular cement.

The Oil and Gas UK Well Integrity Guidelines make reference to hydrocarbon zones and reservoirs. For shale gas formations operators should consider these as hydrocarbon zones (or horizons) for the purposes of casing (and cement) design.

In addition to the guidance in the Oil and Gas UK Well Integrity Guidelines, operators should also consider the following environmental aspects during the well planning risk assessment and casing design processes:

1. The areal extent, including the base, of all local aquifers should be delineated when assessing groundwater, using appropriate techniques dependent on the area (see Section 5.4.3 for guidelines on groundwater isolation).

2. All permeable zones (including groundwater and any local aquifers) should be assessed to achieve adequate isolation by casing with verified cement (see Section 5.4.2 for cement design and evaluation guidelines).

3. Surface casing should be deep enough, along with sufficient cement, to protect groundwater including local aquifers. The final well abandonment (decommissioning) design should be considered at the well design phase. (See Section 5.8. for well suspension and abandonment (decommissioning) guidelines).

Prior to perforating and hydraulic fracturing operations, the production casing should be pressure tested to a pressure that is adequate to meet the well's operational objectives (which should include potential pressures during fracturing operations). Casing testing is covered in Section 6.6 of the Oil and Gas UK Well Integrity Guidelines (Installation and Testing of Barriers).

Casing test pressures should be documented in the well's basis of design documentation and in the operations programme(s).

Casing deformation has been experienced during some fracturing operations and this has been reported as being caused by bedding parallel slip movement. Operators should ensure the risk of casing deformation is considered as part of the well design risk assessment process and they should document any resultant control measures in the well basis of design documentation and in the operations programme(s).

5.4.2. Cement Design and Evaluation

Section 5.5 of the Oil and Gas UK Well Integrity Guidelines concerns cement design and evaluation. Section 5.9 refers to designing a well for the eventual suspension and abandonment including reference to permeable horizons outside the casing.

Section 6.6 concerns the installation and testing of barriers including cement.

Section 6.2 of the Oil and Gas UK Suspension and Abandonment Guidelines contains guidance on the adequacy of annular cement heights as barriers.

See Section 5.4.3 for groundwater isolation guidelines.

The Oil and Gas UK Well Integrity Guidelines refer to the isolation of "the shallowest hydrocarbon interval". Operators should ensure that there is adequate isolation of hydraulic fracturing operations from groundwater and other permeable horizons by ensuring adequate cement isolation in each casing annulus. Cementing into the previous casing, as per the Oil and Gas UK Well Integrity Guidelines, should be the preferred design. If this is not practicable the cement design should be documented to demonstrate that adequate annular isolation of the hydraulic fracturing will be achieved.

In cooperation with the specialist contractor, operators should prepare suitable programmes for cement placement operations, including monitoring of the effectiveness of placement, as part of the operations planning.

Programmes should include contingency plans and procedures to cover the possibility of a failure to meet the cementation design objectives, as per Oil and Gas UK Well Integrity Guidelines.

Any proposed changes to the cementation programme (design) should be covered by the operator's Management of Change (MOC) procedure and subject to well examination.

The final well abandonment (decommissioning) design should be considered at the well planning stage to ensure good practice abandonment at the end of well life. (See Section 5.8).

The Well Operator's well examination arrangements should include the examination of cementation design and programmes as well as cementation operations. (See section 5.10).

5.4.3. Groundwater Isolation

Note on terminology:

"Groundwater" is used in the context of environment law. Groundwater is defined as "all water which is below the surface of the ground in the saturation zone and in direct contact with the ground or subsoil".

Aquifers are underground layers of water-bearing permeable rock or drift deposits from which groundwater can be extracted.

http://www.environment-agency.gov.uk/homeandleisure/117020.aspx

The phrase "permeable zone" is used in the context of well integrity and is based on oil industry practice including the Oil and Gas UK Well Integrity Guidelines and the Suspension and Abandonment Guidelines

which use the phrases "permeable horizons" and "permeable zones" when describing well integrity in the casing annulus and for well abandonment purposes when describing barriers.

Operators should ensure that groundwater is adequately isolated by cemented casing. (See Section 5.4.2 for cement design and evaluation guidelines).

Groundwater should be thoroughly researched by the operator as part of the well design risk assessment process using:

1. Offset well data.

2. Geophysical delineation.

3. Research with local landowners.

4. Research with Local Authorities.

5. Research with utility companies.

Groundwater, including any local aquifers, should be carefully delineated at the well planning stage and operators should include the design of groundwater isolation (and the isolation of other permeable zones) in the well's basis of design documentation and in the operations programme(s) (or equivalent document names). (See Section 5.5 for fracturing containment guidelines).

See Section 8.1 for more detailed guidance on groundwater and aquifer surveys.

The surface casing should be set at a sufficient depth below the bottom of any aquifer/non- saline groundwater in order to provide adequate isolation. Operators should refer to the Oil and Gas UK Guidelines for the Suspension and Abandonment of Wells for information on the adequacy of annular cement heights as barriers.

Operators should ensure that drilling operations through shallow soils and local aquifers are always undertaken using water or water-based mud systems. Details of the mud systems in use should be declared during the planning application and, where required, in accordance with the environmental permitting process.

5.5. Fracturing Containment

As part of the detailed well integrity planning and risk assessment process, operators should ensure that wellbore integrity during fracturing operations is maintained.

Operators should develop a Hydraulic Fracturing Programme (HFP), based on the risk assessment, that describes the control and mitigation measures for fracture containment and for any potential induced seismicity (see Section 5.6).

The proposed design of the fracture geometry should be included in the HFP including (fracturing) target zones, sealing mechanism(s) and aquifers, both those containing fresh and saline groundwater, so as not to allow fracturing fluids to migrate from the designed fracture zone(s). Performance standards should be documented to characterise the basis for the sealing mechanism and to demonstrate that adequate control measures will be implemented. These will be well-dependent but might include microseismic and tiltmeter monitoring of hydraulic fracture growth. Sealing mechanisms include natural geological seals as well as adequate casing and annular cement.

Faults that might impact the hydraulic fracturing seal mechanism should be thoroughly researched and the assessment documented and referenced in the Hydraulic Fracturing Programme to demonstrate that fracturing fluids cannot migrate, via faults, beyond the designated fracturing zones(s).

A detailed HFP will not be available at the planning consent stage since it can only be developed after drilling and well evaluation. In the meantime an outline HFP will be prepared and this will be updated following drilling and well evaluation and prior to consent for Extended Well Testing being sought. The HFP should be made available to the appropriate regulators in accordance with the applicable regulations.

Fracturing operations should be monitored and recorded against the HFP design performance standards. The HFP and fracturing operations should be examined as part of the well examination arrangements (See Section 5.10).

5.6. Seismicity Induced by Hydraulic Fracturing

5.6.1. General Risk Assessment Principles

Very low level microseismic events occur routinely during hydraulic fracturing and are due to the propagation of the engineered fractures. They can be used to evaluate fracture designs.

Other minor seismic events are generally rare but can be induced by hydraulic fracturing in the presence of a pre-stressed fault. These induced events may be perceptible to local communities.

Operators should consider the risks of these induced seismic events as part of their general duty to assess the risks arising from well operations. Using the risk-based approach will enable operators to demonstrate that adequate controls are in place to eliminate the event or to minimise any potential impact.

Operators should include the induced seismicity risk assessment control and mitigation measures in the Hydraulic Fracturing Programme (see Section 5.5).

An evolutionary approach to risk assessment and mitigation should be adopted by operators whereby more conservative assessments and controls are adopted at the exploration/appraisal phase of a development (see below). As experience is gained in the area and where induced seismic events have not occurred, operators may use this as evidence to propose different monitoring and mitigation measures which are sufficient to address the risk. If any induced seismic events do occur during fracturing operations, then the defined control measures can be adopted. The events can then be fully evaluated so that the risk mechanisms are able to be fully understood.

The magnitude of seismicity induced by hydraulic fracturing is affected by pressure changes in the shale formation near to the well. The hydraulic fracturing process fundamentally constrains these pressure changes:

• Pressurisation takes place across a limited volume of rock, typically only a few hundred metres in any direction.

• Pressurisation only takes place over a limited timescale, typically only a few hours.

• Pressure dissipates into the surrounding geology as more fractures are created, limiting the pressure that can build up.

The pressure in the well is also a key determinant of induced seismicity and is affected by:

• The volume of injected fluid. Larger volumes generate higher pressures.

• The volume of flow-back fluid. Larger flow-back volumes reduce the pressure.

• The injection rate. More rapid injection generates higher pressures.

• The flow-back rate. More rapid flow-back reduces the pressure.

5.6.2. Mitigating Induced Seismicity – Fault Characterisation and Identification

The risks of fault movement can be mitigated by the identification of stressed faults and where practicable, by the avoidance of fracturing fluids entering stressed faults.

Risk assessments will depend on such things as:

1. Geological knowledge of the play area.

2. Actual field experience in the area.

3. The depth of fracturing operations.

Therefore risk management will be related to the amount of information available. During the initial planning stages operators should gather sufficient information to evaluate the area.

Operators should carry out site-specific surveys prior to hydraulic fracturing to characterise local stresses and identify nearby faults. Site characterisations could include desk-based studies of existing geological maps, seismic reflection data, and background seismicity data from the BGS. Stress data from nearby boreholes should be integrated (e.g. core data, borehole imaging, calliper logs and evidence of borehole losses). An understanding of the in- situ stress is a key element of well design and fracturing strategy.

Operators should not overlook the potential presence of faults that cannot be detected given the limits of seismic reflection surveys.

Once faults have been identified and geological stresses characterised, operators can assess the orientation and slip tendency of faults and bedding planes.

5.6.3. Pre-fracturing Injection Tests

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The fracture behaviour of a particular formation is commonly characterised using small pre- fracturing injection tests with microseismic monitoring. Subsequent operations can then be modified accordingly. A reasonable period of time should be allowed to elapse following a pre- fracturing injection test to ensure no seismic activity occurs as the injected fluid diffuses away from the well and pressure changes in surrounding rock f5.10. Well Examination (Design and Construction)

Relevant Regulations and Guidelines:

1. DCR Regulation 18 and Guidance.

2. Oil and Gas UK Guidelines for Well Operators on Well Examination.

3. Oil and Gas UK Guidelines for Well Operators on Competency of Well Examiners.

In addition to following the above-referenced guidance, shale gas Well Operators should include in their well examination scheme the arrangements for the examination of the following aspects of well design:ormations are redistributed.

1. Groundwater and aquifer isolation.

2. Fracture containment.

3. Induced seismicity risks.

4. Fracturing and flow-back/testing programmes and operations.

Well examiners of shale gas wells should be provided with these UKOOG Guidelines as well as the referenced Oil and Gas UK Guidelines by the Well Operator.

Well examiners use documentary evidence of well integrity as the primary means of examination to provide assurance to the Well Operator that wells are designed and constructed properly (as per the published DCR Regulation 18 Guidance). It is not the practice that examination schemes need to rely on physical examination of wells, unless reliance cannot be placed on the veracity of the documentary evidence.

However, for the purpose of increasing public confidence in the UK shale gas industry whilst it is in its infancy, UKOOG consider it appropriate for shale gas Well Operators to ask their well examiners to examine certain well integrity and fracturing operations on site, in real time, especially during the early stages of a development to provide a further level of independent oversight. Such, periodic, site visits are to be made at the discretion of the examiner to observe and verify that such operations have been executed satisfactorily in accordance with the approved programme, in addition to assessing documentary evidence of well integrity. The frequency and need for such visits, with experience, would reasonably be expected to reduce with time.

7. Fracturing/Flow-Back Operations

See Section 5.5 for guidelines on fracturing containment. Guidance on well integrity considerations during fluid pumping operations are contained in section 11.7 of the Oil and Gas UK Well Integrity Guidelines.

7.1. Overview

When conducting fracturing and flow-back/testing operations operators should ensure they adhere to and support the following overarching policies:

1. To safeguard the quality of surface water and groundwater resources, through sound wellbore construction practices, sourcing fresh water alternatives where appropriate, and to recycle water for re-use, if practicable.

2. To measure and disclose water usage with the aim of minimising environmental impacts.

3. To support the development of fracturing fluids and additives with the least environmental risks.

4. To continue to advance, collaborate on and communicate technologies and best practices that minimise the potential environmental risks of hydraulic fracturing.

5. To eliminate or, if not practicable, to minimise any fugitive emissions (See Section 10).

6. To make public the substances used in hydraulic fracturing fluids (see Sections 7.4 and 9.2)

The hydraulic fracturing programme should emphasise and commit the operator to environmental protection.

Since fracturing flow-back/testing may involve dangerous substances (in the form of flammable gas) then both BSOR and the Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) apply to these operations. Therefore there are requirements for operators to carry out and record suitable and sufficient risk assessments, to eliminate or reduce of risks from dangerous substances and to provide arrangements to deal with accidents incidents and emergencies during operations. The outputs (control and mitigation measures) from these requirements, including the various, required, Borehole Site Health and Safety Document Plans, will contribute to the overall environmental plan (e.g. the reduction of fugitive emissions).

7.2. Fracturing/Flow-Back Surface Equipment - Design and Verification

Operators should ensure that:

1. Equipment used in fracturing/flow-back/testing operations complies with the Provision and Use of Work Equipment Regulations, Schedule 2(6) ("Maintenance") of the BSOR and Regulation 6 of DSEAR ("Control and Mitigation Measures") and is, therefore, fit for purpose and meets relevant industry standards.

2. Well control equipment used in fracturing/flow-back/testing operations complies with Schedule 2(7) ("Well Control") of the BSOR and is, therefore, fit for purpose and meets industry standards. (Well control equipment both as part of the well pressure envelope and equipment used downstream of the well).

3. Pressure-containing equipment (that may contain hydrocarbons) is subject to a quality control/certification process operated by the equipment owner and that the results from the process are checked by the operator.

4. Pressure vessels used in association with fracturing operations comply with the Pressure Systems Safety Regulations and associated guidance.

5. Prior to commencing fracturing/flow-back/testing operations a thorough site inspection of the total system is carried out in accordance with a written procedure and this inspection is witnessed by the operator's site supervisor.

6. Water transfer systems are designed to site-specific conditions and these systems are routinely tested and monitored during operations.

7. Audits of any third party equipment are reviewed and made available for disclosure.

Any fracturing equipment that forms part of the well pressure envelope is subject to the DCR regulations, including independent well examination.

7.3. Fracturing/Flow-Back/Testing Operations

7.3.1. Planning and Supervision

Operators should ensure that:

1. Fracturing/flow-back/testing operations are planned and fully risk assessed as part of the well design and operations programming process.

2. Suitable and sufficient risk assessments, to eliminate or reduce the risks from dangerous substances (well fluids) being released and their impact on the water environment are carried out, recorded and the findings (control and mitigation measures) implemented.

3. Adequate arrangements are in place to deal with emergencies during fracturing and flowback/testing operations.

4. The Borehole Site Health and Safety Document includes relevant details about the fracturing flow-back/testing operations and (where appropriate) contains plans to deal with:

a. Provision of escape and rescue.

b. Prevention of fire and explosion with particular reference to blowouts and escapes of flammable gas.

c. General fire prevention.

d. Detection and control of toxic gases.

5. Continuing on from the drilling operations phase, a competent person is appointed to be in charge of the well site ("borehole site") and sufficient competent persons are appointed to exercise immediate supervision of operations in accordance with BSOR Schedule 2. (See Section 5.1 for further detail).

6. Sufficient personnel are available who are adequately trained and experienced to operate fracturing/flow-back/testing equipment, emergency shutdown systems and any spill containment equipment.

7.3.2. Fracture/Flow-Back/Testing Programming

Operators should ensure that:

1. Sufficient and suitable fracturing/flow-back/testing programmes and procedures are developed, authorised and disseminated to include:

a. Equipment rig up and testing, including testing the integrity of all high pressure equipment (fracturing wellhead, flowlines, manifolds, piping and pump equipment).

b. Monitoring pressure on the production string and all well annuli during rig up and testing.

c. Monitoring any adjacent or offset wells for pressure on the production string and other well annuli, as required.

d. Monitoring wells on neighbouring well pads, if appropriate.

2. Any changes to programmes follow a Management of Change procedure.

3. Records are maintained for all tests of high pressure equipment.

4. Sufficient testing of the emergency shutdown/pressure safety valve system(s) is undertaken in accordance with a programme or written procedures prior to the start of the first fracturing stage.

5. Procedures are developed to continuously monitor and record the annulus pressures at the wellhead and records are maintained.

6. Procedures are developed to continuously monitor and record the pressures in the annulus between the intermediate casing and the production casing and records are maintained. The procedures should include the actions required if any pressure abnormalities are observed.

7. Fracturing/flow-back/testing programmes and any changes to them are submitted to the well examiner in accordance with the Well Operator's well examination arrangements.

7.3.3. Flow-back/Testing Operations

Operators should ensure that:

1. Programmes and procedures are followed and any necessary changes are authorised in accordance with a management of change procedure.

2. Sufficient and suitable records of operations are completed and disseminated.

3. Operations' records are submitted to the well examiner as part of the Well Operator's well examination arrangements to ensure that operations in progress are examined.

7.4. Fracturing Operations Disclosure

See Section 9.2 for guidelines on fracturing fluid disclosure. The following guidelines relate to the disclosure of operational information by the operator.

The operator will disclose pre-operational information during the planning application process since most documentation provided by the operator will be made available by the Local Planning Authority via their normal "open access" policies, including web-site access.

The following guidelines concern the recommended disclosure of fracturing information only.

In addition to statutory reporting, Operators should have available the following for potential disclosure:

1. Geological information including the proposed depth(s) of the top and the bottom of the formation into which well fracturing fluids are to be injected.

2. Information concerning water supply, usage, recycle and re-use.

3. A detailed description of the well fracturing design, including:

a. Estimated total volume of fluid to be used.

b. Fracturing fluid compositions and concentrations.

c. Anticipated surface and downhole treating pressure range.

d. Maximum injection treating pressure.

e. Estimated or calculated fracture length and fracture height.

f. Annuli and offset well pressure monitoring programme to be performed.

g. Testing and flow-back plans.

4. A detailed post-fracture job report, including:

a. Actual total volume of fluids used.

b. Actual surface and downhole treating pressure range.

c. Maximum injection treating pressure.

d. The actual or calculated fracture length and fracture height.

e. Annuli and offset well pressure monitoring results.

f. Confirmation that wellbore integrity was maintained throughout the operation.

g. Testing and flow-back results.

h. Any operational variations to the pre-job design.

i. Any induced seismic events that have been recorded including any steps taken as a result of recording such events (for example in accordance with the traffic light system).

8. Environmental Management (Construction and Operations)

8.1. Groundwater Surveys

Section 5.4.3 contains guidelines on the well design aspects of groundwater and aquifer isolation.

Groundwater, aquifers and where applicable, mine workings, should be thoroughly researched by the operator as part of the well design and fracturing risk assessment process.

Operators should be aware of any specific planning or environmental permits that may set out requirements in respect of groundwater surveys.

During the well planning phase the following baseline surveys of groundwater and any shallow aquifer(s) should be undertaken by operators. This will allow for subsequent pre- and post- fracturing sampling of the groundwater that can then be compared with the "baseline" value.

1. Surface water sampling at the well site prior to the start of site construction.

2. Groundwater sampling prior to the start of site construction.

3. Surface sampling following site construction, drilling and fracturing operations.

4. Groundwater sampling following site construction, drilling and fracturing operations.

Operators should ensure that all water sampling and analysis is carried out by qualified third party organisations using recognised sampling and analytical methods.

Operators should disclose all ongoing water testing results in accordance with any specific planning requirements or environmental permits. Any anomalies detected that are connected with operations should be risk assessed and reported as required by the regulator (EA/SEPA).

The above survey data should also be reported to the British Geological Survey (BGS) who are collating similar data across the UK.

9. Fracturing Fluids and Water Management

9.1. Fluid Composition

Operators should be committed to minimising and, if possible, the elimination of environmental and health risks associated with fracture fluids and additives.

Operators should assess the potential risks from the use of fracturing fluids and additives and create risk management plans (fracturing programmes) to effectively manage the additives and make the process used to develop specific plans available for public disclosure. This assessment should include:

1. Identifying chemical ingredients and characteristics of each additive.

2. Identifying the volume and concentration of the substances in the fracture fluids.

3. Assessing potential environmental and health risks of fracture fluid additives.

4. Defining operational practices and controls for the identified risks. E.g. the amount of fluids that is likely to be recovered.

5. Incorporating risk management plans for each well fractured.

Operators should lead and support the advancement of new, more environmentally sound, products.

Guidance on the UK methodology for determining the hazardous/non-hazardous status of substances in relation to groundwater can be found at:

http://www.wfduk.org/sites/default/files/Media/120628_JAGDAG_det_meth_final.pdf

9.2. Public Disclosure of Fracture Fluid Composition

Operators will disclose on the UKOOG website, www.ukoog.org.uk, the chemical additives of fracturing fluids on a well-by-well basis.

Information for fluid disclosure should include:

1. Any EA/SEPA authorisations for fluids and their status as hazardous/non-hazardous substances.

2. Material Safety Data Sheets information.

3. Volumes of fracturing fluid, including proppant, base carrier fluid and chemical additives.

4. The trade name of each additive and its general purpose in the fracturing process.

5. Maximum concentrations in percent by mass of each chemical additive.

The Public Disclosure of Fracture Fluid Form is shown in appendix 2 and will be downloadable from www.ukoog.org.uk.

9.3. Disclosure of Flow-back Fluids

The following information should be available for disclosure by the operator concerning flow- back and handling of recovered/produced fluids:

1. The estimated and actual volume of fluid to be recovered during flow-back.

2. The expected rates, pressures and temperatures of fluid recovery and production.

3. Water compositional analysis.

4. Water mineralogical analysis.

5. Any identified contamination issues.

6. Any radioactive contaminated fluids.

7. The proposed method of handling the recovered fluids, including but not limited to, tank requirements, pipeline requirements, flaring, flow-back and storage periods, recycle and re-use for other activities.

8. Proposed disposal method of the recovered fluids up to the end location.

9. Proposed volume of flow-back fluids to be recycled and re-used.

10. Regulatory approval and compliance records.

9.4. Fluid transport

The operator should ensure:

1. Sufficient planning to ensure the minimisation of fluid transport movements and distances.

2. Detailed planning and robust estimation of transport movement is undertaken during the local planning process stage.

3. Regulatory approved transportation, service providers and 3rd party contractors (if out- sourced from the operator) are used for the transport of fluids.

4. Implementation management procedures to address the risks associated with fluid transport.

5. Natural gas is removed from fluids prior to transport and a system for checking and recording is implemented.

9.5. Fluid Storage

Fracture fluid storage and site conditions should be covered in detail during the planning application stage.

Best practice should be adopted to ensure that there is no risk of fluid leaks or spillages, this should include:

1. Fluids stored and mixed in appropriate above-ground tanks that are fit for purpose and meet industry standards.

2. Natural gas removal from fluids prior to storage and a system for checking and recording implemented.

3. Storage site locations should be secure and safe.

Operators should make the following available for disclosure:

1. Tank maintenance records.

2. Tank cleaning records and off-take waste disposal records.

3. The volume and chemical composition of all fluids stored on a location.

9.6. Fracture Fluid Disposal

Operators should always dispose of fracture fluid that is no longer required (or unable to be re- used) at an approved waste management facility in accordance with EA/SEPA regulations.

Guidance on the environmental permitting requirements can be found at the following Environment Agency website:

http://www.environment-agency.gov.uk/business/topics/134508.aspx

In Scotland SEPA guidance is available at:

http://www.sepa.org.uk/customer_information/energy_industry.aspx

10. Minimising Fugitive Emissions

Operators should plan and then implement controls in order to minimise all emissions.

Operators should be committed to eliminating all unnecessary flaring and venting of gas and to implementing best practices from the early design stages of the development and by endeavouring to improve on these during the subsequent operational phases.

Emphasis should be placed on “green completions” whereby best practice during the flow-back period is to use a “reduced emissions completion” in which hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling. However this approach will not always be practicable at the exploration/appraisal stage of a development where separation and flaring of natural gas should be the preferred option, minimising venting of hydrocarbons wherever practicable.

Operators should make available and disclose emissions data in line with best practice and any regulatory reporting requirements (e.g., flaring would be in accordance with DECC approvals etc.).

9.5.3 Canada

9.6.3.1 Alberta

Regulatory Authority: The Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development

Reference Source: Directive 083: Hydraulic Fracturing – Subsurface Integrity, Directive 058: Oilfield Waste Management Requirements for Upstream Petroleum Industry

Licensees must not initiate hydraulic fracturing operations within a zone that extends 200 m horizontally from the surface location of a water well and 100 m vertically from the total depth of the water well (see figure 3), except when using nitrogen as the fracturing fluid for coalbed methane completions (see section 7).

Licensees must not hydraulically fracture within 100 vertical m of the top of the bedrock surface (see figure 4), except when using nitrogen as the fracturing fluid for coalbed methane completions (see section 7).

6.1 Banned Waste Types

All fracturing sands.

All solid wastes.

All halogenated solvents and halogenated organic chemicals (i.e. organic chlorides).

All water based wastes including, but not limited to, produced water, acid water, process water, water based methanol hydrotest fluids, other water based bydrotest fluids, wash fluids, boiler blowdowns, filter wash fluids, and oily water.

All chemical based sludges including, but not limited to, glycol sludges, gas sweetening sludges, and other process sludges. All chemical wastes, whether ''unused" pure, spent, or contaminated. This includes, but is not limited to, all caustics, acids, laboratory chemicals, PCBs, gas sweetening agents, non- hydrocarbon based surface and downhole treating chemicals, glycols, methanol, and treating or softening salts.

31.0 Waste Transportation by Pipelines

31.2 Appropriate Wastes for Disposal via Injection into Pipeline Systems

Appropriate Waste Types

Well servicing fracturing fluids that are produced from the wellbore and are a part of regular production. Fluids transferred as part of a production stream will not require a specific agreement as identified above. Note: well servicing fracturing fluids, whether residual, spent or unused, which have purposely been isolated from the process production system (i.e. cannot be handled by surface separation or treatment usually due to solids content) must not be disposed directly into a pipeline system.

For disposal, sand labelled with a radioactive prescribed substance shall be:

- sent to Atomic Energy of Canada Limited, after making prior arrangement,
- sent, after making prior arrangements, to a facility possessing an appropriate waste facility operating license (WFOL) issued by the AECB, or
- buried at the worksite under at least 30 em of soil, provided that the specific activity is less than one scheduled quantity per kilogram of sand.

9.6.3.2 British Colombia

Regulatory Authority: The BC Oil and Gas Commission (Independent)

Reference Source: Oil and Gas Activities Act. Drilling and Production Regulation

A well permit holder must maintain detailed records of the composition of all fracturing fluids that are used in a well for which the well permit holder is responsible, including, but not limited to: (See document for more.)

A well permit holder must submit to the commission the records referred to in subsection (1) within 30 days after the completion of the well

9.6.3.3 Saskatchewan

Regulatory Authority: Ministry of Energy and Resources

Reference Source: The Oil and Gas Conservation Act. Chapter O-2 of the Revised Statues of Saskatchewan, 1978 (effective February 26, 1979) as amended by the statutes of Saskatchewan, 1982-83, c.1; 1983, c.54; 1988-89, c.31; 1989-90, c.54; 1990-91, c.39; 1993, c.35; 1998, c.30; 2000, c.50; 2001, c.26; 2003, c.29; 2007, c.7; 2010, c.E-9.22; 2011, c.11; and 2014, c.E-13.1 and c.21.

The Oil and Gas Conservation Act. Chapter O-2 of the Revised Statues of Saskatchewan, 1978 (effective February 26, 1979) as amended by the statutes of Saskatchewan, 1982-83, c.1; 1983, c.54; 1988-89, c.31; 1989-90, c.54; 1990-91, c.39; 1993, c.35; 1998, c.30; 2000, c.50; 2001, c.26; 2003, c.29; 2007, c.7; 2010, c.E-9.22; 2011, c.11; and 2014, c.E-13.1 and c.21.

Saskatchewan Hydraulic Fracturing Fluids and Propping Agents Containment and Disposal Guidelines. October 1, 2000. (See document for definitions.)

1.2 Containment of Flowback Fluids and Sands

- Flowback fluids and frac sand shall be contained in a tank.
- Tanks receiving flowback fluids and frac sand from water-based, foam and cross- linked hydrocarbon frac fluid systems shall be placed 23 metres away from the well head unless otherwise approved by Saskatchewan Energy and Mines.
- Tanks receiving flowback fluids and frac sand from polyemulsion, oil-based frac fluid systems or flowback fluids containing any amount of appreciable flammable gas, liquid or solid shall be placed 45 metres away from the well head unless otherwise approved by Saskatchewan Energy and Mines.
- Flowback fluids and frac sands must be contained in such a manner so that they do not constitute a hazard to the environment.

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- Blowing flowback fluids and sands into a pit, sump or on the surface of the lease is expressly prohibited. Flowback fluids and sands should be disposed of in a timely manner (no longer than 90 days, unless otherwise approved).
- Placing hazardous wastes, waste dangerous goods (e.g. used lubricating oil, solvents and antifreeze) or garbage in flowback storage tanks is prohibited. Please refer to the Waste Management Guidelines for the Upstream Oil and Gas Industry, SPIGEC, February 1996.

1.3 Disposal of Flowback Fluids

- All flowback fluids shall be disposed of at an approved waste processing facility with an approved disposal well, unless it is permitted by other methods described in this guideline or the operator receives written permission from Saskatchewan Energy and Mines. Approved waste processing facilities are assigned a WPF number from Saskatchewan Energy and Mines. No additional tests are required other than the tests requested by the waste processing facility operator.
- Flowback fluids from water-based frac fluids and foams may be disposed of at an approved disposal well owned by the operator.
- Flowback fluids from water-based frac fluids and foams may also be disposed of at an approved disposal well owned by a third party operator, who does not have a waste processing facility approval. Prior to disposal, the flowback fluid shall be tested and meet the following criteria:

Parameter	Criteria
pH	greater than 2 and less than
Closed Cup	greater than 61ºC

- Written approval from Saskatchewan Energy and Mines is required prior to implementing new treatment or disposal methods for flowback fluids.
- Discharge of flowback fluids on surface land, surface water or into the environment is strictly prohibited. This restriction applies to natural and man-made features, including but not limited to: agricultural lands, alkaline sloughs, drilling sumps, flare pits, gravel pits, landfarms, landfills,

pipeline right-of-ways, oil and gas surface leases and access roads, remote sumps, seismic lines, sewer systems, tailing ponds, tailing piles and vegetated lands (forest, crops, or native grass).

- The operator is responsible to comply with all other relevant regulatory requirements, for example: requirements specified in The Transportation of Dangerous Goods Regulations.

1.4 Disposal of Frac Sand

- All frac sand can be disposed of at an approved waste processing facility. Approved waste processing facilities are assigned a WPF number from Saskatchewan Energy and Mines. No additional tests are required other than the tests requested by the waste processing facility operator.
- Operators are encouraged to reuse or recycle frac sand whenever possible. Commercial recycling facilities and service providers shall make a written application to the SEM head office to operate in Saskatchewan.
- Management Level 1 Frac Sand (ML1): refers to frac sand generated from water based and foam frac fluid systems that meet all of the criteria listed in the table 1 column ML1. Chemical analysis specified in table 1 column ML1 must be conducted and submitted to SEM by completing Form A-2: Notification Of Flowback Fluid And Frac Sand Disposal. ML1 frac sand may be disposed in:
    - municipal landfills
    - non-SEM approved commercial landfarms
    - commercial/industrial use (construction materials, fill, building materials)
    - other methods approved by SEM (written approval is required)
    - other methods specified in section 1.4 (i.e. WPF, reuse/recycle or ML2)

The operator will be required to obtain permission from the authorized personnel of the disposal facility (i.e. municipal landfill operator), prior to disposal. The operator must comply with any relevant regulatory requirements specified by other regulatory agencies.

9.6.3.4 Ontario

Regulatory Authority: Ministry of Natural Resources

Reference Source: Oil, Gas and Salt Resources of Ontario Provincial Operating Standards, Version 2.0.

(a) only inject oil field fluid (formation water and drilling fluid) into a disposal well that;

(i) is produced by the operator, or

(ii) originates from the same field and is delivered by pipeline to the disposal well;

(b) not inject fluids that are classified as "liquid industrial waste" under the

Environmental Protection Act, including stimulation fluids, unless the well is licensed

by the Ministry of Environment and Energy for that purpose; and

(c) not inject oil field fluid between the outermost casing and the well bore or into the annular space between strings of casing.

9.6.3.5 Quebec

Regulatory Authority: Ministry of Natural Resources and Wildlife

Reference Source: Mining Act. Chapter M-13.1, r. 1, Regulation respecting petroleum, natural gas and underground reservoirs.

Clause 54. A well completion licensee, while processing the stimulation of production, shall not subject the casing to a pressure greater than 75% of its nominal bursting strength.

9.5.4 European Union

1. PURPOSE AND SUBJECT MATTER

1.1. This Recommendation lays down the minimum principles needed to support Member States who wish to carry out exploration and production of hydrocarbons using high-volume hydraulic fracturing, while ensuring that the public health, climate and environment are safeguarded, resources are used efficiently, and the public is informed.

1.2. In applying or adapting their existing provisions implementing relevant Union legislation to the needs and specificities of exploration and production of hydrocarbons using high-volume hydraulic fracturing, Member States are encouraged to apply these principles, which concern planning, installation assessment, permits, operational and environmental performance and closure, and public participation and dissemination of information.

2. DEFINITIONS

For the purpose of this Recommendation:

(a) 'high-volume hydraulic fracturing' means injecting 1 000 m 3 or more of water per fracturing stage or 10 000 m 3 or more of water during the entire fracturing process into a well;

(b) an 'installation' includes any related underground structures designated for the exploration or production of hydrocarbons using high-volume hydraulic fracturing.

3. STRATEGIC PLANNING AND ENVIRONMENTAL IMPACT ASSESSMENT

3.1. Before granting licenses for exploration and/or production of hydrocarbons which may lead to the use of high-volume hydraulic fracturing, Member States should prepare a strategic environmental assessment to prevent, manage and reduce the impacts on, and risks for, human health and the environment. This assessment should be carried out on the basis of the requirements of Directive 2001/42/EC.

3.2. Member States should provide clear rules on possible restrictions of activities, for example in protected, flood-prone or seismic-prone areas, and on minimum distances between authorised operations and residential and water-protection areas. They should also establish minimum depth limitations between the area to be fractured and groundwater.

3.3. Member States should take the necessary measures to ensure that an environmental impact assessment is carried out on the basis of the requirements of Directive 2011/92/EU.

3.4. Member States should provide the public concerned with early and effective opportunities to participate in developing the strategy referred to in point 3.1 and the impact assessment referred to in point 3.3.

4. EXPLORATION AND PRODUCTION PERMITS

Member States should ensure that the conditions and the procedures for obtaining permits in accordance with applicable Union legislation are fully coordinated if:

(a) more than one competent authority is responsible for the permit(s) needed;

(b) more than one operator is involved;

(c) more than one permit is needed for a specific project phase;

(d) more than one permit is needed under national or Union legislation.

5. SELECTION OF THE EXPLORATION AND PRODUCTION SITE

5.1. Member States should take the necessary measures to ensure that the geological formation of a site is suitable for the exploration or production of hydrocarbons using high-volume hydraulic fracturing.

They should ensure that operators carry out a characterisation and risk assessment of the potential site and surrounding surface and underground area.

5.2. The risk assessment should be based on sufficient data to make it possible to characterise the potential exploration and production area and identify all potential exposure pathways. This would make it possible to assess the risk of leakage or migration of drilling fluids, hydraulic fracturing fluids, naturally occurring material, hydrocarbons and gases from the well or target formation as well as of induced seismicity.

5.3. The risk assessment should:

(a) be based on the best available techniques and take into account the relevant results of the information exchange between Member States, industries concerned and non-governmental organisations promoting environmental protection organised by the Commission;

(b) anticipate the changing behaviour of the target formation, geological layers separating the reservoir from groundwater and existing wells or other manmade structures exposed to the high injection pressures used in high-volume hydraulic fracturing and the volumes of fluids injected;

(c) respect a minimum vertical separation distance between the zone to be fractured and groundwater;

(d) be updated during operations whenever new data are collected.

5.4. A site should only be selected if the risk assessment conducted under points 5.1, 5.2 and 5.3 shows that the high-volume hydraulic fracturing will not result in a direct discharge of pollutants into groundwater and that no damage is caused to other activities around the installation.

6. BASELINE STUDY

6.1. Before high-volume hydraulic fracturing operations start, Member States should ensure that:

(a) the operator determines the environmental status (baseline) of the installation site and its surrounding surface and underground area potentially affected by the activities;

(b) the baseline is appropriately described and reported to the competent authority before operations begin.

6.2. A baseline should be determined for:

(a) quality and flow characteristics of surface and ground water;

(b) water quality at drinking water abstraction points;

(c) air quality;

(d) soil condition;

(e) presence of methane and other volatile organic compounds in water;

(f) seismicity;

(g) land use;

(h) biodiversity;

(i) status of infrastructure and buildings;

(j) existing wells and abandoned structures.

7. INSTALLATION DESIGN AND CONSTRUCTION

Member States should ensure that the installation is constructed in a way that prevents possible surface leaks and spills to soil, water or air.

8. INFRASTRUCTURE OF A PRODUCTION AREA

Member States should ensure that:

(a) operators or groups of operators apply an integrated approach to the development of a production area with the objective of preventing and reducing environmental and health impacts and risks, both for workers and the general public;

(b) adequate infrastructure requirements for servicing the installation are established before production begins. If an installation's primary purpose is producing oil using high-volume hydraulic fracturing, specific infrastructure that captures and transports associated natural gas should be installed.

9. OPERATIONAL REQUIREMENTS

9.1. Member States should ensure that operators use best available techniques taking into account the relevant results of the information exchange between Member States, industries concerned and non-governmental organisations promoting environmental protection organised by the Commission, as well as good industry practice to prevent, manage and reduce the impacts and risks associated with projects of exploration and production of hydrocarbons.

9.2. Member States should ensure that operators:

(a) develop project-specific water-management plans to ensure that water is used efficiently during the entire project. Operators should ensure the traceability of water flows. The water management plan should take into account seasonal variations in water availability and avoid using water sources under stress;

(b) develop transport management plans to minimise air emissions in general and the impacts on local communities and biodiversity in particular;

(c) capture gases for subsequent use, minimise flaring and avoid venting. In particular, operators should put in place measures to ensure that air emissions at the exploration and production stage are mitigated by capturing gas and its subsequent use. Venting of methane and other air pollutants should be limited to the most exceptional operational circumstances for safety reasons;

(d) carry out the high-volume fracturing process in a controlled manner and with appropriate pressure management with the objective to contain fractures within the reservoir and to avoid induced seismicity;

(e) ensure well integrity through well design, construction and integrity tests. The results of integrity tests should be reviewed by an independent and qualified third party to ensure the well's operational performance, and its environmental and health safety at all stages of project development and after well closure;

(f) develop risk management plans and the measures necessary to prevent and/or mitigate the impacts, and the measures necessary for response;

(g) stop operations and urgently take any necessary remedial action if there is a loss of well integrity or if pollutants are accidentally discharged into groundwater;

(h) immediately report to the competent authority in the event of any incident or accident affecting public health or the environment. The report should include the causes of the incident or accident, its consequences and remedial steps taken. The baseline study required under points 6.1 and 6.2 should be used as a reference.

9.3. Member States should promote the responsible use of water resources in high-volume hydraulic fracturing.

10. USE OF CHEMICAL SUBSTANCES AND WATER IN HIGH-VOLUME HYDRAULIC FRACTURING

10.1. Member States should ensure that:

(a) manufacturers, importers and downstream users of chemical substances used in hydraulic fracturing refer to 'hydraulic fracturing' when complying with their obligations under Regulation (EC) No 1907/2006;

(b) using chemical substances in high-volume hydraulic fracturing is minimised;

(c) the ability to treat fluids that emerge at the surface after high-volume hydraulic fracturing is considered during the selection of the chemical substances to be used.

10.2. Member States should encourage operators to use fracturing techniques that minimise water consumption and waste streams and do not use hazardous chemical substances, wherever technically feasible and sound from a human health, environment and climate perspective.

11. MONITORING REQUIREMENTS

11.1. Member States should ensure that the operator regularly monitors the installation and the surrounding surface and underground area potentially affected by the operations during the exploration and production phase and in particular before, during and after high-volume hydraulic fracturing.

11.2. The baseline study required under points 6.1 and 6.2 should be used as a reference for subsequent monitoring.

11.3. In addition to environmental parameters determined in the baseline study, Member States should ensure that the operator monitors the following operational parameters:

(a) the precise composition of the fracturing fluid used for each well;

(b) the volume of water used for the fracturing of each well;

(c) the pressure applied during high-volume fracturing;

(d) the fluids that emerge at the surface following high- volume hydraulic fracturing: return rate, volumes, characteristics, quantities reused and/or treated for each well;

(e) air emissions of methane, other volatile organic compounds and other gases that are likely to have harmful effects on human health and/or the environment.

11.4. Member States should ensure that operators monitor the impacts of high-volume hydraulic fracturing on the integrity of wells and other manmade structures located in the surrounding surface and underground area potentially affected by the operations.

11.5. Member States should ensure that the monitoring results are reported to the competent authorities.

12. ENVIRONMENTAL LIABILITY AND FINANCIAL GUARANTEE

12.1. Member States should apply the provisions on environmental liability to all activities taking place at an installation site including those that currently do not fall under the scope of Directive 2004/35/EC.

12.2. Member States should ensure that the operator provides a financial guarantee or equivalent covering the permit provisions and potential liabilities for environmental damage prior to the start of operations involving high- volume hydraulic fracturing.

13. ADMINISTRATIVE CAPACITY

13.1. Member States should ensure that the competent authorities have adequate human, technical and financial resources to carry out their duties.

13.2. Member States should prevent conflicts of interest between the regulatory function of competent authorities and their function relating to the economic development of the resources.

14. CLOSURE OBLIGATIONS

Member States should ensure that a survey is carried out after each installation's closure to compare the environmental status of the installation site and its surrounding surface and underground area potentially affected by the activities with the status prior to the start of operations as defined in the baseline study.

15. DISSEMINATION OF INFORMATION

Member States should ensure that:

(a) the operator publicly disseminates information on the chemical substances and volumes of water that are intended to be used and are finally used for the high-volume hydraulic fracturing of each well. This information should list the names and Chemical Abstracts Service (CAS) numbers of all substances and include a safety data sheet, if available, and the substance's maximum concentration in the fracturing fluid;

(b) the competent authorities should publish the following information on a publicly-accessible internet site within 6 months of this Recommendation's publication and in intervals of no longer than 12 months:

(i) the number of wells completed and planned projects involving high-volume hydraulic fracturing;

(ii) the number of permits granted, the names of operators involved and the permit conditions;

(iii) the baseline study produced under points 6.1 and 6.2 and the monitoring results produced under points 11.1, 11.2 and 11.3(b) to (e);

(c) the competent authorities should also inform the public of the following without undue delay.

(i) incidents and accidents under point 9.2(f);

(ii) the results of inspections, non-compliance and sanctions.

16. REVIEW

16.1. Member States having chosen to explore or exploit hydrocarbons using high-volume hydraulic fracturing are invited to give effect to the minimum principles set out in this Recommendation by 28 July 2014 and to annually inform the Commission about the measures they put in place in response to this Recommendation, and for the first time, by December 2014.

16.2. The Commission will closely monitor the Recommendation's application by comparing the situation in Member States in a publicly available scoreboard.

16.3. The Commission will review the Recommendation's effectiveness 18 months after its publication.

16.4. The review will include an assessment of the Recommendation's application, will consider the progress of the best available techniques information exchange and the application of the relevant BAT reference documents, as well as any need for updating the Recommendation's provisions. The Commission will decide whether it is necessary to put forward legislative proposals with legally-binding provisions on the exploration and production of hydrocarbons using high-volume hydraulic fracturing.

9.6 APPENDIX F – Bureau of Land Management; Hydraulic fracturing.

(a) *Activities to which this section applies.* This section, or portions of this section, apply to hydraulic fracturing as shown in the following table:

If . . .	Then
(1) No APD was submitted as of June 24, 2015	The operator must comply with all paragraphs of this section.
(2) An APD was submitted but not approved as of June 24, 2015	
(3) An APD or APD extension was approved before June 24, 2015, but the authorized drilling operations did not begin until after June 24, 2015	To conduct hydraulic fracturing within 90 days after the effective date of this rule, the operator must comply with all paragraphs of this section, except (c) and (d).
(4) Authorized drilling operations began, but were not completed before June 24, 2015	
(5) Authorized drilling operations were completed after September 22, 2015	
(6) Authorized drilling activities were completed before September 22, 2015	The operator must comply with all paragraphs of this section.

(b) *Isolation of usable water to prevent contamination.* All hydraulic fracturing operations must meet the performance standard in section 3162.5-2(d) of this title.

(c) *How an operator must submit a request for approval of hydraulic fracturing.* A request for approval of hydraulic fracturing must be submitted by the operator and approved by the authorized officer before commencement of operations. The operator may submit the request in one of the following ways:

(1) With an application for permit to drill; or

(2) With a Sundry Notice and Report on Wells (Form 3160-5) as a notice of intent (NOI).

(3) For approval of a group of wells submitted under either paragraph (c)(1) or (2) of this section, the operator may submit a master hydraulic fracturing plan. Submission of a master hydraulic fracturing plan does not obviate the need to obtain an approved APD from the BLM for each individual well.

> *"Note to Reader: It is not recommended to give approval for groups of wells but rather on a case-by-case basis. Drilling details will vary from well to well, even if the same drilling program is used. Some of the variations may affect the fracturing program such as dog-legs in directionally drilled hole sections and loss of circulation events."*
>
> *Dr. Neal Adams*

(4) If an operator has received approval from the authorized officer for hydraulic fracturing operations, and the operator has significant new information about the geology of the area, the stimulation operation or technology to be used, or the anticipated impacts of the hydraulic fracturing operation to any resource, then the operator must submit a new NOI (Form 3160-5). Significant new information includes, but is not limited to, information that changes the proposed drilling or completion of the well, the hydraulic fracturing operation, or indicates increased risk of contamination of zones containing usable water or other minerals.

(d) *What a request for approval of hydraulic fracturing must include.* The request for approval of hydraulic fracturing must include the information in this paragraph. If the information required by this paragraph has been assembled to comply with State law (on Federal lands) or tribal law (on Indian lands), such information may be submitted to the BLM authorized officer as provided to the State or tribal officials as part of the APD or NOI (Form 3160-5).

(1) The following information regarding wellbore geology:

(i) The geologic names, a geologic description, and the estimated depths (measured and true vertical) to the top and bottom of the formation into which hydraulic fracturing fluids are to be injected;

(ii) The estimated depths (measured and true vertical) to the top and bottom of the confining zone(s); and

(iii) The estimated depths (measured and true vertical) to the top and bottom of all occurrences of usable water based on the best available information.

(2) A map showing the location, orientation, and extent of any known or suspected faults or fractures within one-half mile (horizontal distance) of the wellbore trajectory that may transect the confining zone(s). The map must be of a scale no smaller than 1:24,000.

(3) Information concerning the source and location of water supply, such as reused or recycled water, rivers, creeks, springs, lakes, ponds, and water supply wells, which may be shown by quarter-quarter section on a map or plat, or which may be described in writing. It must also identify the anticipated access route and transportation method for all water planned for use in hydraulically fracturing the well;

Note to Reader: Item (3) will not have application in an offshore environment.

(4) A plan for the proposed hydraulic fracturing design that includes, but is not limited to, the following:

(i) The estimated total volume of fluid to be used;

(ii) The maximum anticipated surface pressure that will be applied during the hydraulic fracturing process;

(iii) A map at a scale no smaller than 1:24,000 showing:

(A) The trajectory of the wellbore into which hydraulic fracturing fluids are to be injected;

(B) The estimated direction and length of the fractures that will be propagated and a notation indicating the true vertical depth of the top and bottom of the fractures; and

(C) All existing wellbore trajectories, regardless of type, within one-half mile (horizontal distance) of any portion of the wellbore into which hydraulic fracturing fluids are to be injected. The true vertical depth of each wellbore identified on the map must be indicated.

(iv) The estimated minimum vertical distance between the top of the fracture zone and the nearest usable water zone; and

(v) The measured depth of the proposed perforated or open-hole interval.

(5) The following information concerning the handling of fluids recovered between the commencement of hydraulic fracturing operations and the approval of a plan for the disposal of produced fluid under BLM requirements:

(i) The estimated volume of fluid to be recovered;

(ii) The proposed methods of handling the recovered fluids as required under paragraph (h) of this section; and

(iii) The proposed disposal method of the recovered fluids, including, but not limited to, injection, storage, and recycling.

(6) If the operator submits a request for approval of hydraulic fracturing with an NOI (Form 3160-5), the following information must also be submitted:

(i) A surface use plan of operations, if the hydraulic fracturing operation would cause additional surface disturbance; and

(ii) Documentation required in paragraph (e) or other documentation demonstrating to the authorized officer that the casing and cement have isolated usable water zones, if the proposal is to hydraulically fracture a well that was completed without hydraulic fracturing.

(7) The authorized officer may request additional information prior to the approval of the NOI (Form 3160-5) or APD.

(e) *Monitoring and verification of cementing operations prior to hydraulic fracturing.* (1)(i) During cementing operations on any casing used to isolate and protect usable water zones, the operator must monitor and record the flow rate, density, and pump pressure, and submit a cement operation monitoring report for each casing string used to isolate and protect usable water to the authorized officer prior to commencing hydraulic fracturing operations. The cement operation monitoring report must be provided at least 48 hours prior to commencing hydraulic fracturing operations unless the authorized officer approves a shorter time.

(ii) For any well completed pursuant to an APD that did not authorize hydraulic fracturing operations, the operator must submit documentation to demonstrate that adequate cementing was achieved for all casing strings designed to isolate and protect usable water. The operator must submit the documentation with its request for approval of hydraulic fracturing operations, or no less than 48 hours prior to conducting hydraulic fracturing operations if no prior approval is required, pursuant to paragraph (a) of this section. The authorized officer may approve the hydraulic fracturing of the well only if the documentation provides assurance that the cementing was sufficient to isolate and to protect usable water, and may require such additional tests, verifications, cementing or other protection or isolation operations, as the authorized officer deems necessary.

(2) Prior to starting hydraulic fracturing operations, the operator must determine and document that there is adequate cement for all casing strings used to isolate and protect usable water zones as follows:

(i) *Surface casing.* The operator must observe cement returns to surface and document any indications of inadequate cement (such as, but not limited to, lost returns, cement channeling, gas cut mud, failure of equipment, or fallback from the surface exceeding 10 percent of surface casing setting depth or 200 feet, whichever is less). If there are indications of inadequate cement, then the operator must determine the top of cement with a CEL, temperature log, or other method or device approved in advance by the authorized officer.

(ii) *Intermediate and production casing.* (A) If the casing is not cemented to surface, then the operator must run a CEL to demonstrate that there is at least 200 feet of adequately bonded cement between the zone to be hydraulically fractured and the deepest usable water zone.

(B) If the casing is cemented to surface, then the operator must follow the requirements of paragraph (e)(2)(i) of this section.

(3) For any well, if there is an indication of inadequate cement on any casing used to isolate usable water, then the operator must:

(i) Notify the authorized officer within 24 hours of discovering the inadequate cement;

(ii) Submit an NOI (Form 3160-5) to the authorized officer requesting approval of a plan to perform remedial action to achieve adequate cement. The plan must include the supporting documentation and logs required under paragraph (e)(2) of this section. In emergency situations, an operator may request oral approval from the authorized officer for actions to be undertaken to remediate the cement. However, such requests must be followed by a written notice filed not later than the fifth business day following oral approval;

(iii) Verify that the remedial action was successful with a CEL or other method approved in advance by the authorized officer;

(iv) Submit a Sundry Notice and Report on Wells (Form 3160-5) as a subsequent report for the remedial action including:

(A) A signed certification that the operator corrected the inadequate cement job in accordance with the approved plan; and

(B) The results from the CEL or other method approved by the authorized officer showing that there is adequate cement.

(v) The operator must submit the results from the CEL or other method approved by the authorized officer (see paragraph (e)(3)(iv)(B) of this section) at least 72 hours before starting hydraulic fracturing operations.

(f) *Mechanical integrity testing prior to hydraulic fracturing.* Prior to hydraulic fracturing, the operator must perform a successful mechanical integrity test, as follows:

(1) If hydraulic fracturing through the casing is proposed, the casing must be tested to not less than the maximum anticipated surface pressure that will be applied during the hydraulic fracturing process.

(2) If hydraulic fracturing through a fracturing string is proposed, the fracturing string must be inserted into a liner or run on a packer-set not less than 100 feet below the cement top of the production or intermediate casing. The fracturing string must be tested to not less than the maximum anticipated surface pressure minus the annulus pressure applied between the fracturing string and the production or intermediate casing.

(3) The mechanical integrity test will be considered successful if the pressure applied holds for 30 minutes with no more than a 10 percent pressure loss.

(g) *Monitoring and recording during hydraulic fracturing.*

(1) During any hydraulic fracturing operation, the operator must continuously monitor and record the annulus pressure at the bradenhead. The pressure in the annulus between any intermediate casings and the production casing must also be continuously monitored and recorded. A continuous record of all annuli pressure during the fracturing operation must be submitted with the required Subsequent Report Sundry Notice (Form 3160-5) identified in paragraph (i) of this section.

(2) If during any hydraulic fracturing operation any annulus pressure increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation, the operator must stop the hydraulic fracturing operation, take immediate corrective action to control the situation, orally

notify the authorized officer as soon as practicable, but no later than 24 hours following the incident, and determine the reasons for the pressure increase. Prior to recommencing hydraulic fracturing operations, the operator must perform any remedial action required by the authorized officer, and successfully perform a mechanical integrity test under paragraph (f) of this section. Within 30 days after the hydraulic fracturing operations are completed, the operator must submit a report containing all details pertaining to the incident, including corrective actions taken, as part of a Subsequent Report Sundry Notice (Form 3160-5).

(h) *Management of Recovered Fluids.* Except as provided in paragraphs (h)(1) and ((2) of this section, all fluids recovered between the commencement of hydraulic fracturing operations and the authorized officer's approval of a produced water disposal plan under BLM requirements must be stored in rigid enclosed, covered, or netted and screened above-ground tanks. The tanks may be vented, unless Federal law, or State regulations (on Federal lands) or tribal regulations (on Indian lands) require vapor recovery or closed-loop systems. The tanks must not exceed a 500 barrel (bbl) capacity unless approved in advance by the authorized officer.

Numerous operational accidents during the flow back phase of fracturing operations have resulted in injuries and fatalities, primarily from ignition of hydrocarbon components of the flowback fluids. Crew often overlook safety fundamentals of handling hydrocarbons such as no smoking in the area, separation between ignition sources and flammable hydrocarbons and static electricity. Some flowback operations may take extended time periods, such as days or weeks, which can result in crew complacency.

(1) The authorized officer may approve an application to use lined pits only if the applicant demonstrates that use of a tank as described in this paragraph (h) is infeasible for environmental, public health or safety reasons and only if, at a minimum, all of the following conditions apply:

(i) The distance from the pit to intermittent or ephemeral streams or water sources would be at least 300 feet;

(ii) The distance from the pit to perennial streams, springs, fresh water sources, or wetlands would be at least 500 feet;

(iii) There is no usable groundwater within 50 feet of the surface in the area where the pit would be located;

(iv) The distance from the pit to any occupied residence, school, park, school bus stop, place of business, or other areas where the public could reasonably be expected to frequent would be greater than 300 feet;

(v) The pit would not be constructed in fill or unstable areas;

(vi) The construction of the pit would not adversely impact the hydrologic functions of a 100-year floodplain; and

(vii) Pit use and location complies with applicable local, State (on Federal lands), tribal (on Indian lands) and other Federal statutes and regulations including those that are more stringent than these regulations.

Item (1) (i)-(vi) are not applicable in an offshore environment.

(2) Pits approved by the authorized officer must be:

(i) Lined with a durable, leak-proof synthetic material and equipped with a leak detection system; and

(ii) Routinely inspected and maintained, as required by the authorized officer, to ensure that there is no fluid leakage into the environment. The operator must document all inspections.

(i) *Information that must be provided to the authorized officer after hydraulic fracturing is completed.* The information required in paragraphs (i)(1) through (10) of this section must be submitted to the authorized officer within 30 days after the completion of the last stage of hydraulic fracturing operations for each well. The information is required for each well, even if the authorized officer approved fracturing of a group of wells (see § 3162.3-3(c)). The information required in paragraph (i)(1) of this section must be submitted to the authorized officer through FracFocus or another BLM-designated database, or in a Subsequent Report Sundry Notice (Form 3160-5). If information is submitted through FracFocus or another BLM-designated database, the operator must specify that the information is for a Federal or an Indian well, certify that the information is both timely filed and correct, and certify compliance with applicable law as required by paragraph (i)(8)(ii) or (iii) of this section using FracFocus or another BLM-designated database. The information required in paragraphs (i)(2) though (10) of this section must be submitted to the authorized officer in a Subsequent Report Sundry Notice (Form 3160-5). The operator is responsible for the information submitted by a contractor or agent, and the information will be considered to have been submitted directly from the operator to the BLM. The operator must submit the following information:

(1) The true vertical depth of the well, total water volume used, and a description of the base fluid and each additive in the hydraulic fracturing fluid, including the trade name, supplier, purpose, ingredients, Chemical Abstract Service Number (CAS), maximum ingredient concentration in additive (percent by mass), and maximum ingredient concentration in hydraulic fracturing fluid (percent by mass).

(2) The actual source(s) and location(s) of the water used in the hydraulic fracturing fluid;

(3) The maximum surface pressure and rate at the end of each stage of the hydraulic fracturing operation and the actual flush volume.

(4) The actual, estimated, or calculated fracture length, height and direction.

(5) The actual measured depth of perforations or the open-hole interval.

(6) The total volume of fluid recovered between the completion of the last stage of hydraulic fracturing operations and when the operator starts to report water produced from the well to the Office of Natural Resources Revenue. If the operator has not begun to report produced water to the Office of Natural

Resources Revenue when the Subsequent Report Sundry Notice is submitted, the operator must submit a supplemental Subsequent Report Sundry Notice (Form 3160-5) to the authorized officer documenting the total volume of recovered fluid.

(7) The following information concerning the handling of fluids recovered, covering the period between the commencement of hydraulic fracturing and the implementation of the approved plan for the disposal of produced water under BLM requirements:

(i) The methods of handling the recovered fluids, including, but not limited to, transfer pipes and tankers, holding pond use, re-use for other stimulation activities, or injection; and

(ii) The disposal method of the recovered fluids, including, but not limited to, the percent injected, the percent stored at an off-lease disposal facility, and the percent recycled.

(8) A certification signed by the operator that:

(i) The operator complied with the requirements in paragraphs (b), (e), (f), (g), and (h) of this section;

(ii) For Federal lands, the hydraulic fracturing fluid constituents, once they arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal, State, and local laws, rules, and regulations; and

(iii) For Indian lands, the hydraulic fracturing fluid constituents, once they arrived on the lease, complied with all applicable permitting and notice requirements as well as all applicable Federal and tribal laws, rules, and regulations.

(9) The operator must submit the result of the mechanical integrity test as required by paragraph (f) of this section.

(10) The authorized officer may require the operator to provide documentation substantiating any information submitted under paragraph (i) of this section.

(j) *Identifying information claimed to be exempt from public disclosure.*

(1) For the information required in paragraph (i) of this section, the operator and the owner of the information will be deemed to have waived any right to protect from public disclosure information submitted with a Subsequent Report Sundry Notice (Form 3160-5) or through FracFocus or another BLM-designated database. For information required in paragraph (i) of this section that the owner of the information claims to be exempt from public disclosure and is withheld from the BLM, a corporate officer, managing partner, or sole proprietor of the operator must sign and the operator must submit to the authorized officer with the Subsequent Report Sundry Notice (Form 3160-5) required in paragraph (i) of this section an affidavit that:

(i) Identifies the owner of the withheld information and provides the name, address and contact information for a corporate officer, managing partner, or sole proprietor of the owner of the information;

(ii) Identifies the Federal statute or regulation that would prohibit the BLM from publicly disclosing the information if it were in the BLM's possession;

(iii) Affirms that the operator has been provided the withheld information from the owner of the information and is maintaining records of the withheld information, or that the operator has access and will maintain access to the withheld information held by the owner of the information;

(iv) Affirms that the information is not publicly available;

(v) Affirms that the information is not required to be publicly disclosed under any applicable local, State or Federal law (on Federal lands), or tribal or Federal law (on Indian lands);

(vi) Affirms that the owner of the information is in actual competition and identifies competitors or others that could use the withheld information to cause the owner of the information substantial competitive harm;

(vii) Affirms that the release of the information would likely cause substantial competitive harm to the owner of the information and provides the factual basis for that affirmation; and

(viii) Affirms that the information is not readily apparent through reverse engineering with publicly available information.

(2) If the operator relies upon information from third parties, such as the owner of the withheld information, to make the affirmations in paragraphs (j)(1)(vi) through (viii) of this section, the operator must provide a written affidavit from the third party that sets forth the relied-upon information.

(3) The BLM may require any operator to submit to the BLM any withheld information, and any information relevant to a claim that withheld information is exempt from public disclosure.

(4) If the BLM determines that the information submitted under paragraph (j)(3) of this section is not exempt from disclosure, the BLM will make the information available to the public after providing the operator and owner of the information with no fewer than 10 business days' notice of the BLM's determination.

(5) The operator must maintain records of the withheld information until the later of the BLM's approval of a final abandonment notice, or 6 years after completion of hydraulic fracturing operations on Indian lands, or 7 years after completion of hydraulic fracturing operations on Federal lands. Any subsequent operator will be responsible for maintaining access to records required by this paragraph during its operation of the well. The operator will be deemed to be maintaining the records if it can promptly provide the complete and accurate information to BLM, even if the information is in the custody of its owner.

(6) If any of the chemical identity information required in paragraph (i)(1) of this section is withheld, the operator must provide the generic chemical name in the submission required by paragraph (i)(1) of this section. The generic chemical name must be only as nonspecific as is necessary to protect the

confidential chemical identity, and should be the same as or no less descriptive than the generic chemical name provided to the Environmental Protection Agency.

(k) *Requesting a variance from the requirements of this section.*

(1) Individual variance: The operator may make a written request to the authorized officer for a variance from the requirements under this section. A request for an individual variance must specifically identify the regulatory provision of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator will satisfy the objectives of the regulation for which the variance is being requested.

(2) State or tribal variance: In cooperation with a State (for Federal lands) or a tribe (for Indian lands), the appropriate BLM State Director may issue a variance that would apply to all wells within a State or within Indian lands, or to specific fields or basins within the State or the Indian lands, if the BLM finds that the variance meets the criteria in paragraph (k)(3) of this section. A State or tribal variance request or decision must specifically identify the regulatory provision(s) of this section for which the variance is being requested, explain the reason the variance is needed, and demonstrate how the operator will satisfy the objectives of the regulation for which the variance is being requested. A State or tribal variance may be initiated by the State, tribe, or the BLM.

(3) The authorized officer (for an individual variance), or the State Director (for a State or tribal variance), after considering all relevant factors, may approve the variance, or approve it with one or more conditions of approval, only if the BLM determines that the proposed alternative meets or exceeds the objectives of the regulation for which the variance is being requested. The decision whether to grant or deny the variance request must be in writing and is entirely within the BLM's discretion. The decision on a variance request is not subject to administrative appeals either to the State Director (for an individual variance) or under **43 CFR part 4**.

(4) A variance under this section does not constitute a variance to provisions of other regulations, laws, or orders.

(5) Due to changes in Federal law, technology, regulation, BLM policy, field operations, noncompliance, or other reasons, the BLM reserves the right to rescind a variance or modify any conditions of approval. The authorized officer must provide a written justification before a variance is rescinded or a condition of approval is modified.

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9.7 APPENDIX G – Comparison and Contrast of Regulations

9.7.1 Well Location

USA

State	Rules
Alabama	No fracturing shall not be conducted within ¼ mile radius from any fresh water resources
Alaska	Identify any freshwater aquifer with ½ mile of the well trajectory
Illinois	No high volume fracturing jobs within: • 500 ft of existing water well or developed spring • 500 ft of any residence, commercial building, place of worship, school or hospital • 300 ft of high water mark of any river, lake, pond or reservoir • 750 ft of a nature preserve • 1500 ft of a surface water or groundwater intake of a public water supply
Nevada	The operator must include, with his or her application to drill an oil or gas well, a description of the location of each water source located within the area of review
New York	Operators required to test water wells within: • 1000 ft of well drilling site • Survey area would be extended to 2000 ft if no wells found within 1000 ft.
Oklahoma	Acidizing or fracture processes shall not be permitted to pollute any surface

	or subsurface fresh water
Tennessee	Oil and Gas wells shall be drilled and operated in a manner that protects aquifers and surface waters

Canada

State	Rules
Alberta	Licensees must not initiate hydraulic fracturing operations within a zone that extends • 200 m (656 ft.) horizontally from the surface location of water well and • 100 m (328 ft.) vertically from the total depth of the water well except when using nitrogen as the fracturing fluid for coalbed methane completions.

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9.7.2 Well Construction

USA

State	Rules
Alabama	• A wellbore schematic showing the specifications of the casing and cementing program, including pressure tests and depth interval(s) and name(s) of formation(s) to be fractured is required by the board.
Alaska	An assessment of each casing and cementing operation performed to construct or repair the well. The assessment must include sufficient supporting information, including cement evaluation logs and other evaluation logs approved by the commission, to demonstrate that: • Casing is cemented • Each hydrocarbon zone penetrated by the well is isolated
Arkansas	Surface casing in the well in which the proposed Hydraulic Fracturing Treatment will occur shall be: • Set, and cemented to the surface • Set and cemented at least one hundred (100) feet below the deepest encountered freshwater zone. • Have sufficient internal yield pressure to withstand the anticipated maximum pressures to which the casing will be subjected in the well • If during the setting and cementing of production and/or any intermediate casings the cement program does not occur as submitted, and would cause a reasonably prudent Permit Holder to question the integrity of the cementing program with respect to isolating the zone of Hydraulic Fracturing Treatment from movement of fracture fluids up-hole into the various casing or well bore annuli, the Permit Holder shall immediately notify the Director. In reviewing the report, the Director, or his designee, may require a bond log or other cement evaluation tool to document

	cement integrity and require additional cementing operations or other appropriate well workover efforts necessary to correct any cement deficiencies prior to initiating any Hydraulic Fracturing Treatments in the well.
Illinois	**Surface casing:** • Surface casing shall be used and set to a depth of at least 200 feet, or 100 feet below the base of the deepest fresh water, whichever is deeper, but no more than 200 feet below the base of the deepest fresh water and prior to encountering any hydrocarbon-bearing zones. • The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned • Surface casing must be fully cemented to the surface with excess cements. • Cementing must be by the pump and plug method with a minimum of 25% excess cement with appropriate lost circulation material, unless another amount of excess cement is approved by the Department. • If cement returns are not observed at the surface, the operator must perform remedial actions as appropriate. **Intermediate Casing:** • Must be installed when necessary to isolate fresh water not isolated by surface casing and to seal off potential flow zones, anomalous pressure zones, lost circulation zones and other drilling hazards. • Intermediate casing used to isolate fresh water must not be used as the production string in the well in which it is installed, and may not be perforated for purposes of conducting a hydraulic fracture. • When intermediate casing is installed to protect fresh water, the operator shall set a full string of new intermediate casing at least 100 feet below the base of the deepest fresh water and bring cement to the surface. • In instances where intermediate casing was set solely to protect fresh water encountered below the surface casing shoe, and cementing to the surface is technically infeasible, would result in lost circulation, or both, cement must be brought to a minimum of 600 feet above the shallowest fresh water zone encountered below the surface casing shoe or to the surface if the fresh water zone is less than 600 feet from the surface. • The location and depths of any hydrocarbon-bearing zones or fresh water

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	zones that are open to the wellbore above the casing shoe must be confirmed by coring, electric logs, or testing and must be reported to the Department. • In the case that intermediate casing was set for a reason other than to protect strata that contains fresh water, the intermediate casing string shall be cemented from the shoe to a point at least 600 true vertical feet above the shoe. • If there is a hydrocarbon-bearing zone capable of producing exposed above the intermediate casing shoe, the casing shall be cemented from the shoe to a point at least 600 true vertical feet above the shallowest hydrocarbon-bearing zone or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well (or to the surface if less than 200 feet) is required if the cement bond is not adequate for drilling ahead. **Production Casing:** • Production casing must be run and fully cemented to 500 feet above the top perforated zone, if possible. The Department must be notified at least 24 hours prior to production casing cementing operations. Cementing must be by the pump and plug method with a minimum of 25% excess cement. • At any time, the Department, as it deems necessary, may require installation of an additional cemented casing string or strings in the well. After the setting and cementing of a casing string, except the conductor casing, and prior to further drilling: • The casing string shall be tested with fresh water, mud, or brine to no less than 0.22 psi per foot of casing string length or 1,500 psi, whichever is greater but not to exceed 70% of the minimum internal yield, for at least 30 minutes with less than a 5% pressure loss, except that any casing string that will have pressure exerted on it during stimulation of the well shall be tested to at least the maximum anticipated treatment pressure. • If the pressure declines more than 5% or if there are other indications of a leak, corrective action shall be taken before conducting further drilling and high volume horizontal hydraulic fracturing operations.

	• The operator shall contact the Department's District Office for any county in which the well is located at least 24 hours prior to conducting a pressure test to enable an inspector to be present when the test is done. • A record of the pressure test must be maintained by the operator and must be submitted to the Department on a form prescribed by the Department prior to conducting high volume horizontal hydraulic fracturing operations. • The actual pressure must not exceed the test pressure at any time during high volume horizontal hydraulic fracturing operations.
Louisiana	• Surface casing shall be set a minimum of 100 feet below the base of the USDW and cemented to surface. • Cemented to surface shall be considered in this Section as having actual cement returns noted at the surface. • If cement returns are not observed, the operator shall contact the Injection and Mining Division and obtain approval for the procedures to be used to perform any required additional cementing operations. • Cement shall be allowed to stand a minimum of 12 hours under pressure before initiating pressure test or drilling plug. Under pressure is complied with if one float valve is used or if pressure is held otherwise.
New York	• Surface casing to be set deeply enough to not only isolate fresh water zones but also to serve as an adequate foundation for well control while drilling deeper. • It is also necessary under existing requirements, to the extent possible, to avoid extending the surface casing into shallow gas-bearing zones. • Casing and cementing requirements that are incorporated into permit conditions establish the required surface casing setting depth based on the best available site-specific information. • Each subsequent installation of casing and cement serves to further protect the surface casing and hence, the surrounding fresh water zones. • Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool. • Specific American Petroleum Institute (API) standards, specifications and practices would be incorporated into permit conditions related to well construction. Among these would be requirements to adhere to specifications for centralizer type and for casing and cement quality • Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This

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	directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones • Additional measures to ensure cement strength and sufficiency would be incorporated into permit conditions, also directly addressing gas migration concerns. Compliance would continue to be tracked through site inspections and required well completion reports, and any other documentation the Department deems necessary for the operator to submit or make available for review. • Minimum compressive strength requirements. • Minimum waiting times during which no activity is allowed which might disturb the cement while it sets. • Enhanced requirements for use of centralizers which serve to ensure the uniformity and strength of the cement around the well casing • Required use of more advanced cement evaluation tools.
Ohio	• All casing installed in a well shall be steel alloy casing that has been manufactured and tested consistent with standards established by the American petroleum institute (API) in "5 CT Specification for Casing and Tubing" or ASTM international (ASTM) in "A500/A500M Standard Specification for Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes" and has a minimum internal yield pressure rating designed to withstand at least 1.2 times the maximum pressure to which the casing may be subjected during drilling, production or stimulation operations. • The minimum internal yield pressure rating shall be based upon engineering calculations listed in API "TR 5C-3 Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe used as Casing and Tubing, and Performance Properties Tables for Casing and Tubing." • Reconditioned casing that is permanently set in a well shall be hydrostatically pressure tested with an applied pressure at least 1.2 times the maximum internal pressure to which the casing may be subjected, based upon known or anticipated subsurface pressure, or pressure that may be applied during stimulation, whichever is greater, and assuming no external pressure. The casing shall be marked to verify the test status. The owner shall provide a copy of the test results to the inspector before the casing is installed in the well. • Where subsurface reservoir pressure is unknown and cannot be reasonably anticipated, the owner shall assume a pressure gradient of 0.45 pounds per square inch per foot in a fully evacuated hole, under shut-in conditions. • All hydrostatic pressure tests shall be conducted pursuant to API "5 CT Specification for Casing and Tubing" or other method(s) approved by the

	chief. • Reconditioned casing shall not be set in a well unless it has passed an approved hydrostatic pressure and drift test or has otherwise been approved by the inspector. The inspector shall reject casing that is excessively pitted, patched, bent, corroded, or crimped, or if threads are severely worn or damaged. • In order to verify casing integrity and proper cement displacement, the owner shall pressure test each cemented casing string greater than two hundred feet long: • Immediately upon landing the latch-down plug, the owner shall increase displacement pressure by at least five hundred pounds per square inch and hold pressure for five minutes. If pressure declines by ten per cent or more, casing integrity and cement placement shall be further evaluated and appropriate corrective action shall be taken to verify casing integrity and cement displacement. If the float apparatus does not hold, the owner shall pump the volume that flowed back, and shut in until the cement has sufficiently set. • Prior to drilling the cement plug, the owner shall test any permanently cemented casing strings, at a minimum pump pressure in pounds per square inch calculated by multiplying the length of the casing string by 0.2, but not less than three hundred pounds per square inch. The test pressure may not decline by more than ten per cent during the thirty-minute test period. • If, at the end of thirty minutes of such testing, the pressure shows a drop greater than ten per cent, the owner shall not resume further operations until the condition is corrected. A pressure test demonstrating a pressure drop equal to or less than ten per cent after thirty minutes is evidence that the condition has been corrected. • Casing integrity may be verified in conjunction with blowout preventer testing without a test plug using either the test pressure detailed in this rule, or the pressure required to test the blowout preventer, whichever is greater. • The owner may be required to conduct a casing shoe test after drilling below the surface casing and/or the intermediate casing seat if the pressure gradient of the permitted hydrocarbon reservoir exceeds 0.5 pounds per square inch per foot, or in areas where fracture gradients are unknown. • Before drilling below the first casing string, the owner shall either crown the location around the wellbore to divert fluids to a flow ditch, or construct a liquid-tight cellar at least three feet in diameter to prevent

	surface infiltration of fluids adjacent to the wellbore. If a reserve pit is used to contain cuttings and drilling fluids, the flow ditch from the cellar or crown to the reserve pit shall also be liquid tight. • The production casing shall be cemented with sufficient cement to fill the annular space to a point at least five hundred true vertical feet above the seat in an open-hole vertical completion or the uppermost perforation in a cemented vertical completion, or one thousand feet above the kickoff point of a horizontal well. • If any flow zone is present, including strata that may contain hydrocarbons in commercial quantities or a hydrogen sulfide-bearing flow zone, the casing shall be cemented in a manner that effectively isolates such strata with at least five hundred feet of cement above the zone. • The cement slurry shall be designed to control annular gas migration consistent with recommended methods in API "65-2 Isolating Potential Flow Zones during Construction. • When cementing the production string of a well that will be stimulated by hydraulic fracturing, and the uppermost perforation is less than five hundred feet below the base of the deepest USDW, sufficient cement shall be used to fill the annular space outside the casing from the seat to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the owner shall notify the inspector and perform tests approved by the inspector. After the top of cement outside the casing is determined, the owner or his authorized representative shall contact the inspector and obtain approval for the procedures to be used to perform any required additional cementing operations. • Liners may be set and cemented as production casing, provided that the cemented liner has a minimum of two hundred true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level that is at least five hundred pounds per square inch higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The test pressure may not decline by more than ten per cent during the thirty minute test period. If at the end of a thirty minute pressure test, the pressure has dropped by more than ten per cent, the owner shall not resume operations until the condition is corrected and verified by a thirty minute pressure test. Liners may only be set and cemented as production casing in horizontal shale gas wells. • If operations indicate inadequate cement coverage or isolation of the hydrocarbon bearing zones, the owner shall obtain approval of the

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	inspector for procedures to determine the top of cement and/or perform corrective actions.
Texas	• Cementing of the production casing in a minimum separation well shall be by the pump and plug method. • The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface). • The production casing shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.
Utah	• The method of cementing casing in the hole shall be by pump and plug method, displacement method, or other method approved by the division. • When drilling in wildcat territory or in any field where high pressures are probable, the conductor and surface strings of casing must be cemented throughout their lengths, unless another procedure is authorized or prescribed by the division, and all subsequent strings of casing must be securely anchored. • In areas where the pressures and formations to be encountered during drilling are known, sufficient surface casing shall be run to: • Reach a depth below all known or reasonably estimated, utilizable, domestic, fresh water levels. • Prevent blowouts or uncontrolled flows. • The casing program adopted must be planned to protect any potential oil or gas horizons penetrated during drilling from infiltration of waters from other sources and to prevent the migration of oil, gas, or water from one horizon to another.
West Virginia	• The operator may only drill through fresh groundwater zones in a manner that will minimize any disturbance of the zones. • The operator shall construct the well and conduct casing and cementing activities for all horizontal wells in a manner that will provide for control of the well at all times, prevent the migration of gas and other fluids into the fresh groundwater and coal seams, and prevent pollution of or diminution of fresh groundwater. The rules regarding the casing program shall require the following information:

	• The anticipated depth and thickness of any producing formation • Expected pressures, anticipated fresh groundwater zones • The diameter of the borehole • The casing type, whether the casing to be utilized is new or used, and the depth, diameter, wall thickness, and burst pressure rating for the casing. • The cement type, yield, additives, and estimated amount of cement to be used. • The estimated location of centralizers. • The proposed borehole conditioning procedures. • Any alternative methods or materials required by the secretary as a condition of the well work permit. • A copy of casing program shall be kept at the well site. • Supervisory oil and gas inspectors and oil and gas inspectors may approve revisions to previously approved casing programs when conditions encountered during the drilling process so require • Appropriate installation and use of conductor pipe, which shall be installed in a manner that prevents the subsurface infiltration of surface water or fluids. • Installation of the surface and coal protection casing including remedial procedures addressing lost circulation during surface or coal casing. • Installation of intermediate production casing. • Correction of defective casing and cementing, including requirements that the operator report the defect to the secretary within twenty-four hours of discovery by the operator • Investigation of natural gas migration, including requirements that the operator promptly notify the secretary and conduct an investigation of the incident • Any other procedure or requirements considered necessary by the secretary.

Norway

State	Rules
Norway	• Casing, liner and tieback-strings shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations.

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	• The design process shall cover the complete well or section lifespan encompassing all stages from installation to permanent abandonment and include effects of goods deterioration. • Design basis and margins shall be known and documented. Weak-points shall be identified and documented. • All casing strings that are part of a well barrier in subsequent phases shall be logged for wear after drilling if simulation shows wear exceeding maximum allowed wear, based on casing design. • For drilling and completion operations conducted through-tubing where all or parts of the completion string will serve as a WBE, the tubing with all relevant accessories shall be reclassified to production casing and re-qualified to relevant load cases. All primary and secondary WBEs shall be verified to comply with the new design loads prior to commencing operation. • As a minimum the following should be addressed in the design process: o Planned well trajectory and bending stresses induced by doglegs and hole curvature o Maximum allowable setting depth with regards to kick margin o Estimated pore pressure development o Estimated formation integrity development o Estimated temperature gradient and temperature related effects o Drilling fluids and cement program o Loads induced by well services and operations o Completion design requirements o Estimated casing wear o Setting depth restrictions due to formation evaluation requirements; o Potential for H2S, C02 o Metallurgical considerations o Well abandonment requirements o ECO and surge/swab effects due to narrow annulus clearances o Isolation of weak formation, potential loss zones, sloughing and caving formations and protection of reservoir o Geo-tectonic forces o Relief well feasibility o Experience from previous wells in the area or similar wells.

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9.7.3 Hydraulic Fracturing

USA

State	Rules
Alabama	The program for the proposed fracturing operation is required, information to be included, but not limited to: • The max length and orientation of the fracture(s) to be propagated • The type of fluids and materials that are to be utilized • Description of the fracture fluid identified by additive, e.g., acid, proppant, surfactant • The name of the chemical compound and the Chemical Abstracts Service Registry number, if such registry number exists, as published by the Chemical Abstracts Service, a division of the American Chemical Society, for each constituent added to the base fluid
Alaska	When hydraulic fracturing is done through production casing or through intermediate casing: • The casing must be tested to 110 percent of the maximum anticipated pressure differential to which the casing may be subjected. • If the casing fails the pressure test, the casing must be repaired or the operator must use a fracturing string. When hydraulic fracturing is done through a fracturing string, the fracturing string must be: • Stung into a liner or run on a packer set at a measured depth of not less than 100 feet below the cement top of the production casing or intermediate casing • Tested to not less than 110 percent of the maximum anticipated pressure differential to which the fracturing string may be subjected.
Arkansas	• The Permit Holder shall monitor all casing annuli that would be diagnostic as to a potential loss of well bore integrity during the Hydraulic Fracturing

	Treatment. • The Permit Holder shall establish methods to timely relieve any excessive pressures to avoid the loss of surface casing integrity • The Permit Holder shall report detailed information of the Hydraulic Fracturing Treatment: o The maximum pump pressure measured at the surface during each stage The types and volumes of the hydraulic fracturing fluid and proppant used for each stage o The calculated fracture height as designed to be achieved during the Hydraulic Fracturing Treatment and the estimated TVD to the top of the fracture o The names of all specific Additives for each Additive type o The actual rate or concentration for each such Additives expressed as pounds per thousand gallons or gallons per thousand gallons o Additionally, the additives are to be expressed as a percent by volume of the total Hydraulic Fracturing Fluids and Additives
California	• The operator shall notify the Division at least 72 hours prior to commencing well stimulation so that Division staff may witness. • Three hours prior to commencing, the operator shall confirm with the Division that the well stimulation treatment is proceeding
Colorado	• The placement of all stimulation fluids shall be confined to the objective formations during treatment to the extent practicable • During stimulation operations, bradenhead annulus pressure shall be continuously monitored and recorded on all wells being stimulated. • If at any time during stimulation operations the bradenhead annulus pressure increases more than 200 psig the operator shall verbally notify the Director as soon as practicable, but no later than twenty-four (24) hours following the incident. • If intermediate casing has been set on the well being stimulated, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded. • The operator shall keep all well stimulation records and pressure charts on file and available for inspection by the Commission for a period of at least five (5) years.
Illinois	• Any hydraulic fracturing string used in the high volume horizontal hydraulic fracturing operations must be either strung into a production liner or run with a packer set at least 100 feet below the deepest cement top and must

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	be tested to not less than the maximum anticipated treating pressure minus the annulus pressure applied between the fracturing string and the production or immediate casing. • The pressure test shall be considered successful if the pressure applied has been held for 30 minutes with no more than 5% pressure loss. • A function- tested relief valve and diversion line must be installed and used to divert flow from the hydraulic fracturing string-casing annulus to a covered watertight steel tank in case of hydraulic fracturing string failure. • The relief valve must be set to limit the annular pressure to no more than 95% of the working pressure rating of the casings forming the annulus. • The annulus between the hydraulic fracturing string and casing must be pressurized to at least 250 psi and monitored. • A formation pressure integrity test must be conducted below the surface casing and below all intermediate casing. The operator shall notify the Department's District Office for any county in which the well is located at least 24 hours prior to conducting a formation pressure integrity test to enable an inspector to be present when the test is done. A record of the pressure test must be maintained by the operator and must be submitted to the Department on a form prescribed by the Department prior to conducting high volume horizontal hydraulic fracturing operations. • The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during high volume horizontal hydraulic fracturing operations. • The pressure exerted on treating equipment including valves, lines, manifolds, hydraulic fracturing head or tree, casing and hydraulic fracturing string, if used, must not exceed 95% of the working pressure rating of the weakest component. • The high volume horizontal hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during high volume horizontal hydraulic fracturing operations. • It is unlawful to inject or discharge hydraulic fracturing fluid, produced water, BTEX, diesel, or petroleum distillates into fresh water. • It is unlawful to perform any high volume horizontal hydraulic fracturing operations by knowingly or recklessly injecting diesel. • A detailed description of the proposed high volume horizontal hydraulic fracturing operations, including, but not limited to, the following: • The formation affected by the high volume horizontal hydraulic fracturing operations, including, but not limited to, geologic name and geologic description of the formation that will be stimulated by the operation • The anticipated surface treating pressure range;

	• The maximum anticipated injection treating pressure; • The estimated or calculated fracture pressure of the producing and confining zones • The planned depth of all proposed perforations or depth to the top of the open hole section • A chemical disclosure report identifying each chemical and proppant anticipated to be used in hydraulic fracturing fluid for each stage of the hydraulic fracturing operations including the following: • The total volume of water anticipated to be used • The type and total volume of the base fluid anticipated to be used in the hydraulic fracturing treatment, if something other than water • Each hydraulic fracturing additive anticipated to be used, including the trade name, vendor, a brief descriptor of the intended use or function of each hydraulic fracturing additive, and the Material Safety Data Sheet (MSDS), if applicable. • Each chemical anticipated to be intentionally added to the base fluid, including for each chemical, the Chemical Abstracts Service number, if applicable. • The anticipated concentration in the base fluid, in percent by mass, of each chemical to be intentionally added to the base fluid
Kansas	The operator shall submit to the commission a list of each hydraulic fracturing treatment. The list shall include the following information, as a percentage by mass of the total amount of hydraulic fracturing fluid: • The base fluid used, including its total volume • Each proppant • Each chemical constituent at its maximum concentration in the hydraulic fracturing fluid and its CAS number.
Kentucky	• The use of diesel fuel as an additive in fracturing fluids shall be regulated under the Underground Injection Control (UIC) program pursuant to the Safe Water Drinking Act. • Any well owner/operator that contracts with a well service company to use diesel fuel as a fracturing fluid or an additive must first obtain a Class II permit from USEPA-Region VI prior to performing the fracturing treatment. • If the Division of Oil and Gas receives primacy of the UIC-Class II program, the well operator must comply with any provisions as it relates to stimulation using diesel fuel as directed by USEPA.

Louisiana	• All slurry fracture injection wells shall be equipped with injection tubing and a packer. • The packer shall be set in the long string casing no higher than 150 feet above the perforated interval. • the operator shall, for purposes of disclosure, report the following information on or with the well history and work resume report: o The types and volumes of the Hydraulic Fracturing Fluid (base fluid) used during the hydraulic fracture Stimulation operation expressed in gallons. o A list of all additives used during the Hydraulic Fracture Stimulation Operation, such as acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, scale inhibitor, proppant and surfactant. o For each additive type, , the specific trade name and suppliers of all the additives utilized during the Hydraulic Fracture Stimulation Operation o A list of chemical ingredients contained in the hydraulic fracturing fluid that are subject to the requirements of 29 CFR Section 1910.1200(g)(2) and their associated CAS numbers o The maximum ingredient concentration within the additive expressed as a percent by mass for each chemical ingredient o The maximum concentration of each chemical ingredient expressed as a percent by mass of the total volume of hydraulic fracturing fluid used
Mississippi	Within thirty (30) days following the completion of the Hydraulic Fracturing Treatment, the operator shall, for the purpose of disclosure, report the following information to the Supervisor: • The maximum pump pressure measured at the surface during each stage of the Hydraulic Fracturing Treatment unless reasonable grounds for confidentiality exist in which event a request for confidential • It may be submitted to the Supervisor who shall be authorized to waive the disclosure of such data for a period of six (6) months and for an additional six (6) months upon written request to the Supervisor at the Supervisor's sole discretion. • The types and volumes of the Base Fluids and Additives used for each stage of the Hydraulic Fracturing Treatment expressed in gallons or pounds.

	• The calculated fracture height as designed to be achieved during the Hydraulic Fracturing Treatment and the estimated TVD to the top of the fracture. • A list of all Additives used during the Hydraulic Fracturing Treatment specified by general type, such as acids, biocides, breakers, corrosion inhibitors, cross-linkers, demulsifiers, friction reducers, gels, iron controls, oxygen scavengers, pH adjusting agents, scale inhibitors, proppants and surfactants. • For each additive type listed, the specific trade name and suppliers of all the additives utilized during the Hydraulic Fracturing Treatment; and • If the operator causes any Additives to be used during the Hydraulic Fracturing Treatment not otherwise disclosed by the person performing such treatment, the operator shall disclose a list of all Chemical Constituents and associated CAS numbers contained in such additives. • A list of Chemical Constituents intentionally added to the Base Fluids and their associated CAS numbers • The maximum ingredient concentrations within the additive expressed as a percent by mass for each chemical ingredient. • The maximum concentration of each chemical expressed as a percent by mass of the total volume of Hydraulic Fracturing Fluids utilized
Montana	An adequate description of the proposed well stimulation should include: • The estimated total volume of treatment to be used. • The trade name or generic name of the principle components or chemicals. • The estimated amount or volume of the principle components such as viscosifiers, acids, or gelling agents. • The estimated weight or volume of inert substances such as proppants and other substances injected to aid in well cleanup, either for each stage of a multistage job or for the total job. • The maximum anticipated treating pressure or a written description of the well construction specifications which demonstrate that the well is appropriately constructed for the proposed fracture stimulation . • A description of the interval(s) or formation treated. • The type of treatment pumped (acid, chemical, fracture stimulation).

	• The amount and type(s) of material pumped and the rates and maximum pressure during treatment. For hydraulic fracturing treatments the description of the amount and type of material used must include: • A description of the stimulation fluid identified by additive type (e.g. acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant). • The chemical ingredient name and the Chemical Abstracts Service (CAS) Registry number, as published by the Chemical Abstracts Service, a division of the American Chemical Society
Nebraska	• If the operator proposes stimulation through production casing or through intermediate casing, the casing must be tested to the maximum anticipated treating pressure. If the casing fails the pressure test, it must be repaired or the operator must use a temporary casing string (fracturing string). • If the operator proposes fracturing through a temporary casing/tubing string it must be stung into a liner or run on a packer set not less than one hundred (100) feet below the cement top of the production or intermediate casing and must be tested to not less than maximum anticipated treating pressure. • Casing/tubing pressure test will be considered successful if the pressure applied has been held for ten (10) minutes with no more than a ten percent pressure loss. • Maximum treating pressure shall not exceed the test pressure determined above. • The surface casing valve must remain open while hydraulic fracturing operations are in progress. The annular space between the fracturing string and production casing must be monitored and may be pressurized to a pressure not to exceed the pressure rating of the lowest rated component that would be exposed to pressure should the fracturing string fail.
Nevada	The operator shall monitor and record: • All well head pressures, including each annular space pressure, during the hydraulic fracturing operation. • The maximum hydraulic pressure to which a segment of casing is exposed must not exceed the burst-pressure rating of the casing, but the Division

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	may require a lower maximum hydraulic pressure as the Division determines is necessary. • The operator shall immediately stop the hydraulic fracturing process and notify the Division if any change in annular space pressure is observed which suggests communication with the hydraulic fracturing fluids. • The source and estimated volume of water required for hydraulic fracturing
New Mexico	The operator shall file a hydraulic disclosure form that includes : • The fracture date • The well's production type (oil or gas) • The well's gross fractured interval • The well's true vertical depth • The total volume of fluid pumped • A description of the hydraulic fluid composition and concentration listing: o Each ingredient and for each ingredient the trade name o Supplier o Purpose, chemical abstract service number o Maximum ingredient concentration in additive as percentage by mass o Maximum ingredient concentration in the hydraulic fracturing fluid as percentage by mass • If perforating, fracturing or treating a well damages the producing formation, injection interval, casing or casing seat and may create underground waste or contaminate fresh water, the operator shall within five working days notify in writing the division and proceed with diligence to use the appropriate method and means for rectifying the damage. • If perforating, fracturing or chemical treating results in the well's irreparable damage the division may require the operator to properly plug and abandon the well.
North Carolina	• The production casing shall withstand the maximum anticipated treating pressure of the proposed well stimulation operations. The maximum anticipated treating pressure shall not exceed 80 percent of the minimum internal yield pressure for such production casing. • Non-cemented portions of the oil or gas well shall be tested prior to well stimulation operations to ensure that the wellbore can meet one of the following conditions: o 70 percent of the lowest activating pressure for pressure actuated sleeve completions

	o 70 percent of formation integrity for open-hole completions, as determined by a formation integrity test (FIT). • The permittee shall monitor and record, at all times, the following parameters during well stimulation operations: o Surface injection pressure, in pounds per square inch (psi) o Fluid injection rate in barrels per minute (BPM) o Proppant concentration in pounds per thousand gallons o Fluid pumping rate in BPM o Identities, rates, and concentrations of additives used o All annuli pressures. The permittee shall submit a Well Stimulation Report that includes the following information: • The type of oil or gas well. • The well shooting or perforation record detailing the true vertical and measured depths, and total number of shots in the wellbore. • The wellbore diagram that includes casing and cement data, perforations, and a stimulation summary. • The initial oil or gas well test information recording daily gas, oil, and water rate, and tubing and casing pressures • The initial gas analysis, performed by a laboratory certified by the State • The total volume of the base fluid. • The total volume of reused water, alternative water, freshwater, or other base fluid that was used in each hydraulic fracturing stage. • The maximum pump pressure measured at the surface during each stage of the hydraulic fracturing operations. • Types and volumes of the well stimulation fluid and proppant used for each stage of the well stimulation operations. • The well stimulation treatment data collected • For hydraulic fracture stimulations, the estimated maximum fracture height and length and estimated true vertical depth to the top of the fracture achieved during well stimulation treatments as determined by a three dimensional model using true treating pressures and other data collected during the hydraulic fracturing treatments

	• Any substance identified by one or more of the following Chemical Abstract Service Registry Numbers shall not be used in the subsurface: o 68334-30-5, Primary Name: Fuels, diesel; o 68476-34-6, Primary Name: Fuels, diesel, Number 2 o 68476-30-2, Primary Name: Fuel oil Number 2 o 68476-31-3, Primary Name: Fuel oil, Number 4 o 8008-20-6, Primary Name: Kerosene. • Drilling fluids and hydraulic fracturing fluids shall not be formulated to include benzene, toluene, ethylbenzene, or xylene
North Dakota	For hydraulic fracture stimulation performed through a frac string run inside the intermediate casing string: • The frac string must be either stung into a liner or run with a packer set at a minimum depth of one hundred feet below the top of cement or one hundred feet below the top of the Inyan Kara formation, whichever is deeper. • The intermediate casing-frac string annulus must be pressurized and monitored during frac operations. • An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should the relief valve open. The relief valve must be set to limit line pressure to no more than eighty-five percent of the internal yield pressure of the frac string. • An adequately sized, function tested pressure relief valve and an adequately sized diversion line must be utilized to divert flow from the intermediate casing to a pit or containment vessel in case of frac string failure. • The relief valve must be set to limit annular pressure to no more than eighty-five percent of the lowest internal yield pressure of the intermediate casing string or no greater than the pressure test on the intermediate casing, less one hundred pounds per square inch gauge, whichever is less. • The surface casing must be fully open and connected to a diversion line rigged to a pit or containment vessel.

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Ohio	• All annuli shall be pressure-monitored. • Stimulation or workover operations shall be immediately suspended for any inexplicable pressure deviation above those anticipated increases caused by pressure or thermal transfer. • In the event that stimulation fluids circulate, or annular pressures deviate from anticipated, the owner shall immediately notify the inspector and acquire approval for remediation of casing or cement. • The stimulation of the well has resulted in irreparable damage to the well, the chief shall order that the well be plugged and abandoned within thirty days of issuance of the order.
Oklahoma	• No oil, gas, or deleterious substances shall be permitted to pollute any surface or subsurface fresh water. • The operator must submit information on the chemicals used in the hydraulic fracturing. The information required must include the following: o The dates on which the hydraulic fracturing operation began and ended o The total volume of base fluid used in the hydraulic fracturing operation o The type of base fluid used. o The trade name, supplier, and general purpose of each chemical additive or other substance intentionally added to the base fluid. For each ingredient in any chemical additive or other substance intentionally added to the base fluid, the identity, Chemical Abstract Service (CAS) number, and maximum concentration. o The maximum concentration for any ingredient must be presented as the percent by mass in the hydraulic fracturing fluid as a whole, and is not required to be presented as the percent by mass in any particular additive. o The phrase “chemical additive or other substance intentionally added to the base fluid” refers to a substance knowingly and purposefully added to the base fluid and does not include trace amounts of impurities, incidental products of chemical reactions or processes, or constituents of natural materials.
Pennsylvania	The completion report shall contain the operator's stimulation record. The stimulation record shall include all of the following: • A descriptive list of the chemical additives in the stimulation fluids,

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	including any acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, Ph adjusting agent, proppant, scale inhibitor and surfactant. • The trade name, vendor and a brief descriptor of the intended use or function of each chemical additive in the stimulation fluid. • A list of the chemicals intentionally added to the stimulation fluid, by name and chemical abstract service number. • The maximum concentration, in percent by mass, of each chemical intentionally added to the stimulation fluid. • The total volume of the base fluid. • A list of water sources used under the approved water management plan and the volume of water used. • The pump rates and pressure used in the well. • The total volume of recycled water used.
South Dakota	the operator shall post on the FracFocus Chemical Disclosure Registry the following stimulation detail: • Fracture date • Production type, • True vertical depth • Hydraulic fracturing fluid composition as follows: o Total water volume o Chemical trade name o Supplier o Purpose o Intentionally added ingredients o Chemical abstract number o Maximum ingredient concentration in additive o Maximum ingredient concentration in hydraulic fracturing fluid.
Tennessee	For fracturing treatments using more than 200,000 gallons of water-based liquids: • The operator shall conduct pressure monitoring during the fracturing

	treatment to monitor for a successful treatment and for protection of the groundwater. • Annulus pressure shall be continuously monitored and recorded for all such fracturing treatments. • If intermediate casing has been set, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded. • Records of pressure monitoring shall be included as part of the well history reporting requirements • The total volume of water used in the hydraulic fracturing of the well or the type and total volume of the base fluid used in the fracturing, if something other than water. • Each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief descriptor of the intended use of function of each hydraulic fracturing additive in the hydraulic fracturing fluid. • Each chemical intentionally added to the base fluid. • The maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid. • The chemical abstract service number for each chemical intentionally added to the base fluid, if applicable.
Texas	• All casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or fracture tubing may be subjected. • The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method. • Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. • A surface pressure loss of greater than 10 percent of the initial test pressure is considered a failed test. The casing required to be pressure tested shall be from the wellhead to at least the depth of the top of cement behind the casing being tested. • The district director shall be notified of a failed test within 24 hours of completion of the test.

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	• In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing). During hydraulic fracturing treatment operations: • The operator shall monitor all annuli. • The operator shall immediately suspend hydraulic fracturing treatment operations if the pressure deviates above those anticipated increases caused by pressure or thermal transfer. • The operator shall notify the appropriate district director within 24 hours of such deviation. • Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan. • As soon as possible, but not later than 15 days following the completion of hydraulic fracturing treatment(s) on a well, the supplier or the service company must provide to the operator of the well the following information concerning each chemical ingredient intentionally added to the hydraulic fracturing fluid: o Each additive used in the hydraulic fracturing fluid and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment o Each chemical ingredient subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2) o The actual or maximum concentration of each chemical ingredient in percent by mass o The CAS number for each chemical ingredient, if applicable.
West Virginia	• Practices involving reuse of water in the fracturing and stimulating of horizontal wells should be considered and encouraged, as appropriate • A listing of the anticipated additives that may be used in water utilized for fracturing or stimulating the well. • Upon well completion, a listing of the additives that were actually used in the fracturing or stimulating of the well shall be submitted as part of the completion log or report.

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Wyoming	• Well stimulation operations within the Trona Interval shall include a post stimulation survey that identifies the extent of induced fractures. Results of the survey shall be submitted to the Supervisor for evaluation to determine if induced fractures have significantly intersected the Trona Mineral Resources and if corrective action is required. • The Owner or Operator shall provide detailed information to the Supervisor as to the base stimulation fluid source. • The Owner or Operator or service company shall provide to the Supervisor, for each stage of the well stimulation program, the chemical additives, compounds and concentrations or rates proposed to be mixed and injected, including: o Stimulation fluid identified by additive type (such as but not limited to acid, biocide, breaker, brine, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, pH adjusting agent, proppant, scale inhibitor, surfactant) o The chemical compound name and Chemical Abstracts Service (CAS) number shall be identified (such as the additive biocide is glutaraldehyde, or the additive breaker is aluminum persulfate, or the proppant is silica or quartz sand, and so on for each additive used). o The proposed rate or concentration for each additive shall be provided (such as gel as pounds per thousand gallons, or biocide at gallons per thousand gallons, or proppant at pounds per gallon, or expressed as percent by weight or percent by volume, or parts per million, or parts per billion). o The Owner or Operator or service company may also provide a copy of the contractor’s proposed well stimulation program design including the above details o The Supervisor retains discretion to request from the Owner or Operator and/or the service company, the formulary disclosure for the chemical compounds used in the well stimulation(s). • The Owner or Operator shall provide a detailed description of the proposed well stimulation design, which shall include: o The anticipated surface treating pressure range o The maximum injection treating pressure o The estimated or calculated fracture length and fracture height.

	• The injection of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates, into groundwater is prohibited. • The proposed use of volatile organic compounds, such as benzene, toluene, ethylbenzene and xylene, also known as BTEX compounds or any petroleum distillates for well stimulation into hydrocarbon bearing zones is authorized with prior approval of the Supervisor. • It is accepted practice to use produced water that may contain small amounts of naturally occurring petroleum distillates as well stimulation fluid in hydrocarbon bearing zones. • The Owner or Operator or service company shall provide the Supervisor, the following post well stimulation detail: o The actual total well stimulation treatment volume pumped. o Detail as to each fluid stage pumped, including actual volume by fluid stage, proppant rate or concentration, actual chemical additive name, type, concentration or rate, and amounts. o The actual surface pressure and rate at the end of each fluid stage and the actual flush volume, rate and final pump pressure. o The instantaneous shut-in pressure, and the actual 15-minute and 30-minute shut-in pressures when these pressure measurements are available. • During the well stimulation operation, the Owner or Operator shall monitor and record the annulus pressure at the bradenhead. If intermediate casing has been set on the well being stimulated, the pressure in the annulus between the intermediate casing and the production casing shall also be monitored and recorded. • If during the stimulation, the annulus pressure increases by more than five hundred (500) pounds per square inch gauge (psig) as compared to the pressure immediately preceding the stimulation, the Owner or Operator shall verbally notify the Supervisor as soon as practicable but no later than twenty-four (24) hours following the incident.

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Norway

State	Rules
	• If the anticipated maximum pumping pressure exceeds the rated WP of the production tree, or a correspondingly lower pressure if production tree pressure rating has been reduced by corrosion or erosion, the production tree shall be isolated from the pumping pressure by a production tree isolation tool. • Injection shall not be performed into any formation which has the ability to: o Propagate vertical fractures to the seabed o Flow, unless there is a SCSSV installed in the tubing or a SCSSV in the specific annulus used for injection, or if static hydrostatic pressure of the injected fluid column exceeds the pore pressure. • Surface production tree – Remotely actuated tree valves should be isolated from inadvertent closure during pumping operations. • Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts. • It shall be verified that all well equipment and surface equipment can withstand the planned loads induced by the pumping operations. Historical operational data for the well shall be reviewed and the equipment pressure rating shall be downgraded as required based on measured or estimated material loss caused by corrosion, erosion and other factors that may have affected the integrity of the equipment. • Assess abrasive erosion from all fluids and its content (sand, gravel etc) and pressure surge by accidental closure of a valve in the flow conduit when pumping at maximum allowable rate. • The following applies when pumping through production tubing: • The SCSSV and HMV should be isolated from inadvertent closure during pumping operations. • Neighbor annulus and/or pipes isolated from the injection shall be monitored on a regular basis for pressure build up. The cause of any pressure increase (temperature, pipe expansion or leak) shall be verified. • After pumping, the pressure in the A annulus shall be monitored regularly

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	until the temperature equilibrium is reached. • The following applies when handling or pumping liquefied gases or liquids containing gases: o All surface hoses and piping lines used on the low pressure side of the liquid gas shall be qualified for liquid gas service and the specific gas to be pumped. o It should be possible to drain the lowest point of surface hoses and piping lines to minimize the risk of having ice blocks. o All equipment used for storing and/or pumping liquefied gases shall be positioned in a bounded area. The bounded area shall be arranged to: o collect and contain accidental spills of liquefied gases o provide thermal insulation of deck and construction o have water hoses with fine spray nozzle available • The discharge line should have a one-way check valve and pressure bleed-off arrangement. • Rubber hoses should not be used as a part of the high pressure discharge line. • The injection pump shall be fitted with a pressure limit switch, which shall be set to 1.1 times the maximum allowable pumping pressure. • When temporarily installed surface discharge lines are used in conjunction with pumping operations, the following applies: o They shall be adequately anchored to prevent whipping, bouncing, or excess vibration, and to constrain all piping if a break should occur. o Precautions shall be taken and reviewed with relevant personnel to ensure that they are not damaged by dropped objects from cranes, trolleys, skidding systems etc. o Their WP shall be equal to or exceed the maximum expected pumping pressure and should not be less than 34.5 MPa. o They shall be leak tested to a pressure exceeding maximum allowable pumping pressure, after installation and prior to use. o They should have sufficient ID to avoid erosion from the pumping operation. o A check valve shall be installed in each discharge line as close to the connection point as possible. A bleed-off line between the check valve(s) and the production tree master valve should be installed to enable venting of trapped pressure.

	o They shall be equipped with a pressure relief valve set and checked for the maximum allowable pumping pressure. The relief valve should discharge into a non-hazardous location. • Flexible hoses should not be used when expected pumping pressure exceeds 34,5 MPa. • Flexible hoses should only be exposed to water based fluids. • The WP shall be minimum 34,5 MPa and the design burst pressure shall be four times the WP. • The inner surface of the flexible hose should be neoprene rubber which is not corrosive to HCl. • The construction of the external armor should be banded stainless steel rather that braided. • Integral end fittings should be used. • Minimum bend radius shall be verified for the specific flexible hose in use.

9.7.4 Waste Management and Environmental Impact

State	Rules
Alabama	Diesel oil or fuel is prohibited in any fluid mixture used in the hydraulic fracturing of a formation
California	Operators shall adhere to the following requirements for the storage and handling of well stimulation treatment fluid, additives, and produced water from a well that has had a well stimulation treatment: • Fluids shall be stored in compliance with the secondary containment requirements of Section 1773.1, except that secondary containment is not required under this section for production facilities that are in one location for less than 30 days. • The operator's Spill Contingency Plan shall account for all production facilities outside of secondary containment and include specific steps to be taken and equipment available to address a spill outside of secondary containment.
Colorado	Oily waste may be treated or disposed as follows: • Disposal at a commercial solid waste disposal facility. • Land treatment on site. • Land treatment at a centralized E&P waste management facility permitted in accordance with Rule 908.
Illinois	• Hydraulic fracturing additives, hydraulic fracturing fluid, hydraulic fracturing flowback, and produced water shall be stored in above-ground tanks during all phases of high volume horizontal hydraulic fracturing, and production operations until removed for proper disposal. • Tanks shall be closed, watertight, and corrosion resistant. The permittee shall routinely inspect the tanks for corrosion. • The use of a lined reserve pit is allowed for the temporary storage of

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	hydraulic fracturing flowback. The pit lining system shall be designed to have a capacity at least equivalent to 110% of the maximum volume of hydraulic fracturing flowback anticipated to be recovered • Hydraulic fracturing fluids and hydraulic fracturing flowback must be removed from the well site within 60 days after completion of high volume horizontal fracturing operations • Tanks, piping, and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating, be able to resist corrosion, and be maintained in a leak-free condition. • Fluid transfer operations from tanks to tanker trucks must be supervised at the truck and at the tank if the tank is not visible to the truck operator from the truck. During transfer operations, all interconnecting piping must be supervised if not visible to transfer personnel at the truck and tank. • Hydraulic fracturing flowback must be tested for volatile organic chemicals, semi-volatile organic chemicals, inorganic chemicals, heavy metals, and naturally occurring radioactive material prior to removal from the site. Testing shall occur once per well site and the analytical results shall be filed with the Department and the Agency, and provided to the liquid oilfield waste transportation and disposal operators. • Prior to plugging and site restoration, the ground adjacent to the storage tanks and any hydraulic fracturing flowback reserve pit must be measured for radioactivity. • Hydraulic fracturing flowback may only be disposed of by injection into a Class II injection well that is below interface between fresh water and naturally occurring Class IV groundwater. • Produced water may be disposed of by injection in a permitted enhanced oil recovery operation. • Hydraulic fracturing flowback and produced water may be treated and recycled for use in hydraulic fracturing fluid for high volume horizontal hydraulic fracturing operations. • Discharge of hydraulic fracturing fluids, hydraulic fracturing flowback, and produced water into any surface water or water drainage way is prohibited. • Transport of all hydraulic fracturing fluids, hydraulic fracturing flowback, and produced water by vehicle for disposal must be undertaken by a liquid oilfield waste hauler permitted by the Department

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	• Any release of hydraulic fracturing fluid, hydraulic fracturing additive, or hydraulic fracturing flowback, used or generated during or after high volume horizontal hydraulic fracturing operations shall be immediately cleaned up and remediated pursuant to Department requirements. • Any release of hydraulic fracturing fluid or hydraulic fracturing flowback in excess of 1 barrel, shall be reported to the Department. • Any release of a hydraulic fracturing additive shall be reported to the Department in accordance with the appropriate reportable quantity thresholds established under the federal Emergency Planning and Community Right- to-Know Act. • Any release of produced water in excess of 5 barrels shall be cleaned up, re mediated, and reported pursuant to Department requirements. • No more than one hour before initiating any stage of the high volume horizontal hydraulic fracturing operations, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order. • The results of this inspection must be recorded and documented by the operator, and available to the Department upon request. • A report on the transportation and disposal of the hydraulic fracturing fluids and hydraulic fracturing flowback shall be prepared and included in the well file. • The report must include the amount of fluids transported, identification of the company that transported the fluids, the destination of the fluids, and the method of disposal.

State	Rules
New Mexico	• If fracturing or treating a well damages the producing formation, injection interval, casing or casing seat and may create underground waste or contaminate fresh water, the operator shall within five working days notify in writing the division and proceed with diligence to use the appropriate method and means for rectifying the damage.

	• If fracturing or chemical treating results in the well's irreparable damage, the division may require the operator to properly plug and abandon the well
New York	• Operators shall provide secondary containment around all additive staging areas and fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans. • The comprehensive Stormwater Pollution Prevention Plan (SWPPP) would incorporate by reference a Spill Prevention, Control and Countermeasures Plan. • Before a fracturing permit is issued, the operator must disclose plans for disposal of flowback water and production brine. • To store flowback water on-site, operators would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames. • Full analysis and approvals under state water laws and regulations are required before a water treatment facility can accept flowback from high-volume hydraulic fracturing operations. • An applicant proposing discharge to a Publicly-Owned Treatment Works (POTW) would be required to submit a treatment capacity analysis for the receiving POTW, and, in the event that the POTW is the primary fluid disposal plan, a contingency plan.
North Carolina	E & P waste shall be managed as: • Reuse in well stimulation operations • Onsite pretreatment for reuse or disposal • Disposal at a plant installed for the purpose of disposing of waste within the State • Disposal facility located within another state that is duly permitted to accept flowback fluid and produced water from oil or gas operations
North Dakota	• If damage results to the casing or the casing seat from perforating, fracturing, or chemically treating a well, the operator shall immediately notify the commission and proceed with diligence to use the appropriate method and means for rectifying such damage. • If perforating, fracturing, or chemical treating results in irreparable damage which threatens the mechanical integrity of the well, the commission may require the operator to plug the well.

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Ohio	• Stimulation operations shall be immediately suspended for any inexplicable pressure deviation above those anticipated increases caused by pressure or thermal transfer. • In the event that stimulation fluids circulate, or annular pressures deviate from anticipated, the owner shall immediately notify the inspector and acquire approval for remediation of casing or cement. • The stimulation of the well has resulted in irreparable damage to the well, the chief shall order that the well be plugged and abandoned within thirty days of issuance of the order.
Tennessee	• Discharge from well sites shall be taken to prevent or minimize soil erosion and pollution of surface waters. • The operator shall maintain personnel on-site during fracturing activities, and during the initial flow back period, until such time as the well pressure returns to near pre-fracturing reservoir pressure. • Unmanned flowback operations shall be checked routinely.
Utah	The owner or operator shall: • Take all reasonable precautions to avoid polluting lands, streams, reservoirs, natural drainage ways, and underground water. • Carry on all operations and maintain the property at all times in a safe and workmanlike manner having due regard for the preservation and conservation of the property and for the health and safety of employees and people residing in close proximity to those operations. • Take reasonable steps to prevent and remove accumulations of oil or other materials deemed to be fire hazards from the vicinity of well locations, lease tanks and pits. • Remove from the property or store in an orderly manner, all scrap or other materials not in use. • Provide secure workmanlike storage for chemical containers, barrels, solvents, hydraulic fluid, and other non-exempt materials. • Maintain tanks in a workmanlike manner that will prevent leakage and provide for all applicable safety measures, and construct berms of sufficient height and width to contain the quantity of the largest tank at the storage facility. • Not use crude or produced water storage tanks without tops, except during

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	well testing operations. • Catch leaks and drips, contain spills, and cleanup promptly. • Reduce disposal volumes by recycling and practicing waste reduction approach • Dispose of Produced water, tank bottoms and other miscellaneous waste in a manner that is in compliance with these rules and other state, federal, or local regulations or ordinances. • Use good housekeeping practices. • contact the Division to verify the status of the facility, before using a commercial disposal facility the operator may • Each site and/or facility used for disposal must be permitted and in good standing with the division.
Wyoming	• The Owner or Operator shall provide information to the Supervisor on Well as to the amounts, handling, and if necessary, disposal at an identified appropriate disposal facility, or reuse of the well stimulation fluid load recovered during flow back, swabbing, and/or recovery from production facility vessels. Storage of such fluid shall be protective of groundwater as demonstrated by the use of either tanks or lined pits.

Canada

State	Rules
Alberta	• Banned Waste Types : o All fracturing sands. o All solid wastes. o All halogenated solvents and halogenated organic o All water based wastes including, but not limited to, produced water, acid water, process water, water based methanol hydrotest fluids, other water based bydrotest fluids, wash fluids, boiler blowdowns, filter wash fluids, and oily water. o All chemical based sludges including, but not limited to, glycol sludges, gas sweetening sludges, and other process sludges. o All chemical wastes, whether 'unused, spent, or contaminated, this includes, but is not limited to, all caustics, acids, laboratory chemicals,

	PCBs, gas sweetening agents, non- hydrocarbon based surface and downhole treating chemicals, glycols, methanol, and treating or softening salts. • Appropriate Wastes for Disposal via Injection into Pipeline Systems o Well servicing fracturing fluids that are produced from the wellbore and are a part of regular production. o Fluids transferred as part of a production stream will not require a specific agreement as identified above. o Well servicing fracturing fluids, whether residual, spent or unused, which have purposely been isolated from the process production system (i.e. cannot be handled by surface separation or treatment usually due to solids content) must not be disposed directly into a pipeline system. • For disposal, sand labelled with a radioactive prescribed substance shall be: o Sent to Atomic Energy of Canada Limited o Sent to a facility possessing an appropriate waste facility operating license (WFOL) issued by the AECB. o Buried at the worksite under at least 30 m of soil, provided that the specific activity is less than one scheduled quantity per kilogram of sand.
Ontario	• Only inject oil field fluid (formation water and drilling fluid) into a disposal well that is: o Produced by the operator o Originates from the same field and is delivered by pipeline to the disposal well • Do not inject fluids that are classified as "liquid industrial waste" under the Environmental Protection Act, including stimulation fluids, unless the well is licensed by the Ministry of Environment and Energy for that purpose • Do not inject oil field fluid between the outermost casing and the well bore or into the annular space between strings of casing.

9.7.5 Seismicity

USA

State	Rules

California	• From commencement of hydraulic fracturing until 10 days after the end of hydraulic fracturing, the operator shall monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of five times the ADSA. • If an earthquake of magnitude 2.7 or greater is identified, then the following requirements shall apply: o The operator shall immediately notify the Division and inform the Division when the earthquake occurred relative to the hydraulic fracturing operations. o The Division, in consultation with the operator and the California Geological Survey, will conduct an evaluation of the following: o Whether there is indication of a causal connection between the hydraulic fracturing and the earthquake. o Whether there is a pattern of seismic activity in the area that correlates with nearby hydraulic fracturing o Whether the mechanical integrity of any active well within the radius specified in subdivision (a) has been compromised. o No further hydraulic fracturing shall be done within a radius a radius of five times the ADSA until the Division has completed the evaluation, and is satisfied that hydraulic fracturing within that radius does not create a heightened risk of seismic activity.
Illinois	• The Department shall adopt rules, in consultation with the Illinois State Geological Survey, establishing a protocol for controlling operational activity of Class II injection wells in an instance of induced seismicity. • Induced seismicity means an earthquake event that is felt, recorded by the national seismic network, and attributable to a Class II injection well used for disposal of flow-back and produced fluid from hydraulic fracturing operations. • The rules adopted by the Department under this Section shall employ a "traffic light" control system allowing for low levels of seismicity while including additional monitoring and mitigation requirements when seismic events are of sufficient intensity to result in a concern for public health and safety.

9.8 APPENDIX H – Hydraulic Stimulation: A Case History

9.8.1 Introduction

Case histories can often provide additional insight and understanding of a process than can be gained from a technical narrative of the same process. The case history shown here provides a description of a hydraulic fracturing on a US land well. The type of operation is typical of hydraulic fracturing operations found on most land wells currently being drilled and fractured in the United States.

This case history was selected to serve an additional purpose. Failures in casing strings and/or couplings are becoming frequent occurrences during stimulation operations. The well may be remediated in some instances or lost in other cases, primarily depending on the circumstances involving the failure. The industry's level of understanding has not yet provided technical guidance as to the source (cause) of the failure or the means to prevent these occurrences. The case history shown here is exemplar of casing/coupling failures during well stimulation.

9.8.2 Case History

Oil Company, Inc. drilled and completed the Oil Well No. 1 during the time period of June-July 2013. The well was placed on production in August 2013 and is currently believed to be producing commercial quantities of oil and gas. It appears that Oil Company, Inc. produces oil and gas from several additional wells proximate to the subject well.

An overview of the chronology of operations on the Oil Well No. 1 well is shown in Table 17.

The available records through 21 September indicate the continued production of commercial quantities of oil and gas.

Table 20 – Oil Well No. 1 events in chronological order.

Chronology Overview	
2013	Operations
10 June	Commenced move in and rig up operations. Drilling Contractor's Rig 1 at the site.
13 June	Well was spudded at 0600 hrs.
13 June	Ran and cemented 9-5/8 inch surface casing to 435 feet.
26 June	Ran and cemented 7 inch, 26 pounds per foot ("ppf"), J-55 grade casing to 7321 feet measured depth ("md").
27 June	Started drilling the lateral section of the hole at 21 June.
7 July	Ran and cemented 4.5 inch, P-110 grade casing, LT&C connectors to 12,069 feet, md.
8 July	The rig was released at 0400 hrs.
17 July	Started fracturing and acidizing operations.
26 July	Initial indication of some type of problem while fracturing the 15th stage over the interval of 9160-9282 feet, md.
27 July	Notation in the daily drilling reports, "Possible hole in casing." Perform fracturing for 16th stage.
31 July	Did not attempt fracturing 17th stage.
-	Move in workover rig to complete well via gas lift.
24 August	Put the well online at 1715 hours.
30 August	Initial flow.
16 September	Producing 261.7 barrels of oil per day ("bopd") and 1,628,000 standard cubic feet of gas per day ("scfd").

9.8.3 Drilling Operations

Oil Company, Inc. contracted Drilling Contractor to provide its Rig 1 for drilling the Oil Well No. 1 well. After the location was leveled and prepared, Drilling Contractor started moving Rig 1 to the location and rigging it up. The well was spudded at 0600 hrs on 13 June.

A 12.25 inch OD drill bit was used to drill the surface hole to 435 feet. Oil Company, Inc. contracted with a third party company to provide the equipment and trained personnel to run the 9-5/8 inch casing. The string of pipe consisted of a guide shoe; one joint of 9-5/8 inch, 36 pounds per foot ("ppf"), J-55 grade, ST&C pipe; a float collar and 12 joints of the 9-5/8 inch casing. Turbo-centralizers were placed on the pipe string at the depths of 442, 334, 227 and 113 feet. The lead slurry consisted of 125 sacks of Extended Lite cement mixed to a density of 13.4 pounds per gallon (“ppg”). The tail slurry contained 125 sacks of regular cement at 15.6 ppg. Full returns were observed at the surface while the cement was circulated down the inside of the casing, out the bottom and up the annulus (space between casing and drilled rock formation).

On 14 June, the blowout preventers (“BOPs”) were pressure tested prior to drilling the intermediate section of the well. An 8.75 inch bit was used to drill to the depth of 7,350 feet by 25 June. A loss of circulation was observed at 6,682 feet on 19 June while drilling the intermediate section of the well. Loss of circulation occurs when pumping down the casing and up the annulus and 100% of the pumped fluids do not return to the surface. Some amount of fluid enters the rock formation and is forever lost. When the problem was encountered, various amounts of special granular materials are added to the drilling fluids to assist in plugging the loss circulation interval. This effort was partially successful. A total of 450 barrels of drilling mud fluid was lost to the rock.

To resolve the losses after the failed attempts with the special lost circulation materials, Oil Company, Inc. elected to pump cement to the bottom of the well. This approach is also commonly used to combat loss of circulation. On 20 June, 250 sacks of Class H cement mixed to a density of 16.4 ppg were pumped. Partial returns were observed during the process. The depth at which the losses were encountered is also the approximate depth at which directional drilling started.

A string of 7 inch, 26 ppf, J-55 grade, LT&C pipe was run to 7321 feet measured depth (“MD”). While running the casing in the well, significant difficulties were encountered. The bottom 1,236 feet had to be washed to bottom due to *tight hole*. The washing process is required when the wellbore is unstable and constricts the path for running the casing. The process involves pumping down the casing and up the annulus while lowering the casing in the well. A complete loss of circulation occurred when the depth of the pipe was 6,700 ft. MD and a 90% loss occurred when the pipe was at 6,900 ft. MD. The ability to perform an effective cement job under these circumstances is likely to be compromised.

The casing was cemented with 200 sacks of Class H cement mixed to 15.8 ppg. The drilling reports indicate that fluid returns were not observed at the surface during the circulation process but that the lift pressure of 800 psi was in the normal range. The available information made available is insufficient to evaluate the effective of the cement job.

On 28 June, a 6.125 inch drill bit was used to start drilling the lateral section of the well to 12,069 feet. The total depth was reached on 5 July. On 6 July, a service provider rigged up and ran a Borehole Imaging Log to establish the optimum portions of the lateral hole for perforating and fracturing (Figures 7 and 8). The production casing was run to 12,068 feet on 8 July. The casing consisted of 288 joints of 4.5 inch, 11.6 ppf, P-110 grade, LT&C casing. A dual float shoe was run on bottom (Figure 9). The casing was run with a total of 48 solid body, 5-bladed turbolizers with the first turbolizer installed at 10 feet above the shoe and then every third joint of casing. A marker joint, 21.25 feet in length, was located in the 4.5 inch string at 6979 – 7000 feet. Typically, a marker joint is noticeably shorter in length than other joints of casing in the string of pipe. The purpose of the marker joint is to allow depth correlation with wireline run in the well during the completion operations. The hole angle at the marker joint was 45 degrees. The drilling rig was released at 0400 hours on 8 July after the casing was cemented.

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Compact Micro-Imager
Interpretation Results

Service Co.

COMPANY: **OIL COMPANY, INC**

WELL: **OIL WELL NO.1-15H**

FIELD: **FIELD**

COUNTY: **COUNTY** STATE: **STATE**

Location: **SEC 00 TWP00N RGE0W** Latitude:

API: **00000-0000** Longitude:

Licence:

Other Services:

Permanent Datum: GL Elevation: 1001 feet
Log measured from KB 0.00 Feet above Permanent Datum
Drilling measured from KB @

Elevations: K.B.: 1017.00 Fee
D.F.: 1016.00 Fee
G.L.: 1001.00 Fee

Date		01-JAN-2015		
Run Number		1		
Service Order		0000000		
Depth Driller		12069.00 Feet		
Depth Logger		12069.00 Feet		
First Reading		11990.00 Feet		
Last Reading		7326.00 Feet		
Casing Driller		244.48	@ 7317.00 Feet	@
Casing Logger		7317.00 Feet		
Bit Size		6.25 inches		
Hole Fluid Type		WATER		
Density	Viscosity	8.70 lb/USg	27.00 CP	
pH	Fluid Loss	10.50	24.00 ml/30Min	
Sample Source		FLOWLINE		
Rm @ Measured Temperature		0.88 ohm-m	@ 93.50 deg F	@
Rmf @ Measured Temperature		0.70 ohm-m	@ 93.50 deg F	@
Rmc @ Measured Temperature		1.06 ohm-m	@ 93.50 deg F	@
Source Rmf	Rmc	CALC		
Rm @ BHT		0.55	@ 155.00 deg F	@
Time Since Circulation				
Maximum Recorded Temperature		155.00 deg F	@	@
Equipment No.	Location	18108	OKC	
Recorded By		GUTHMUELLER		
Witnessed By		T DANIEL		

Figure 7 – Header of borehole imaging log.

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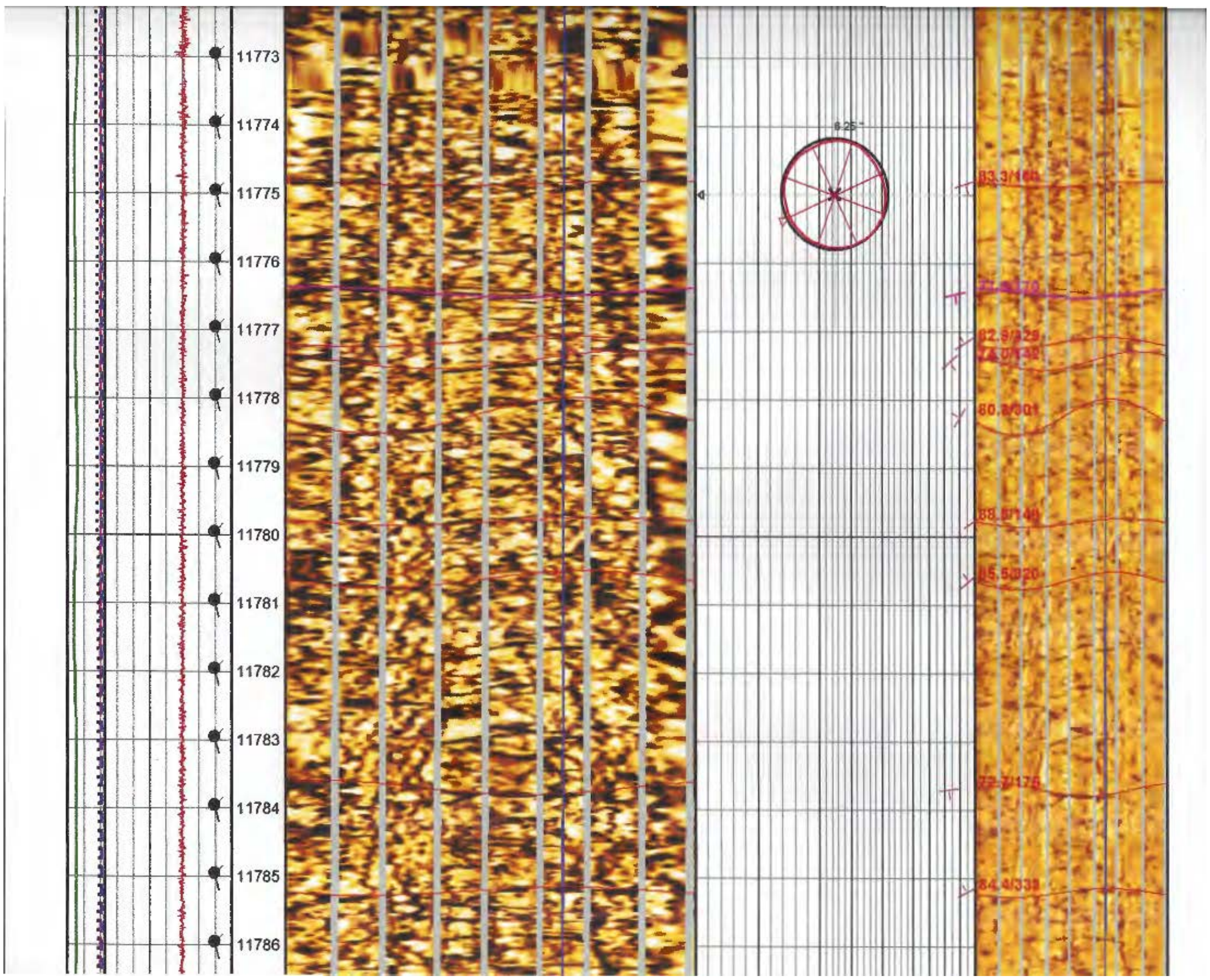

Figure 8 – Section of borehole imaging log.

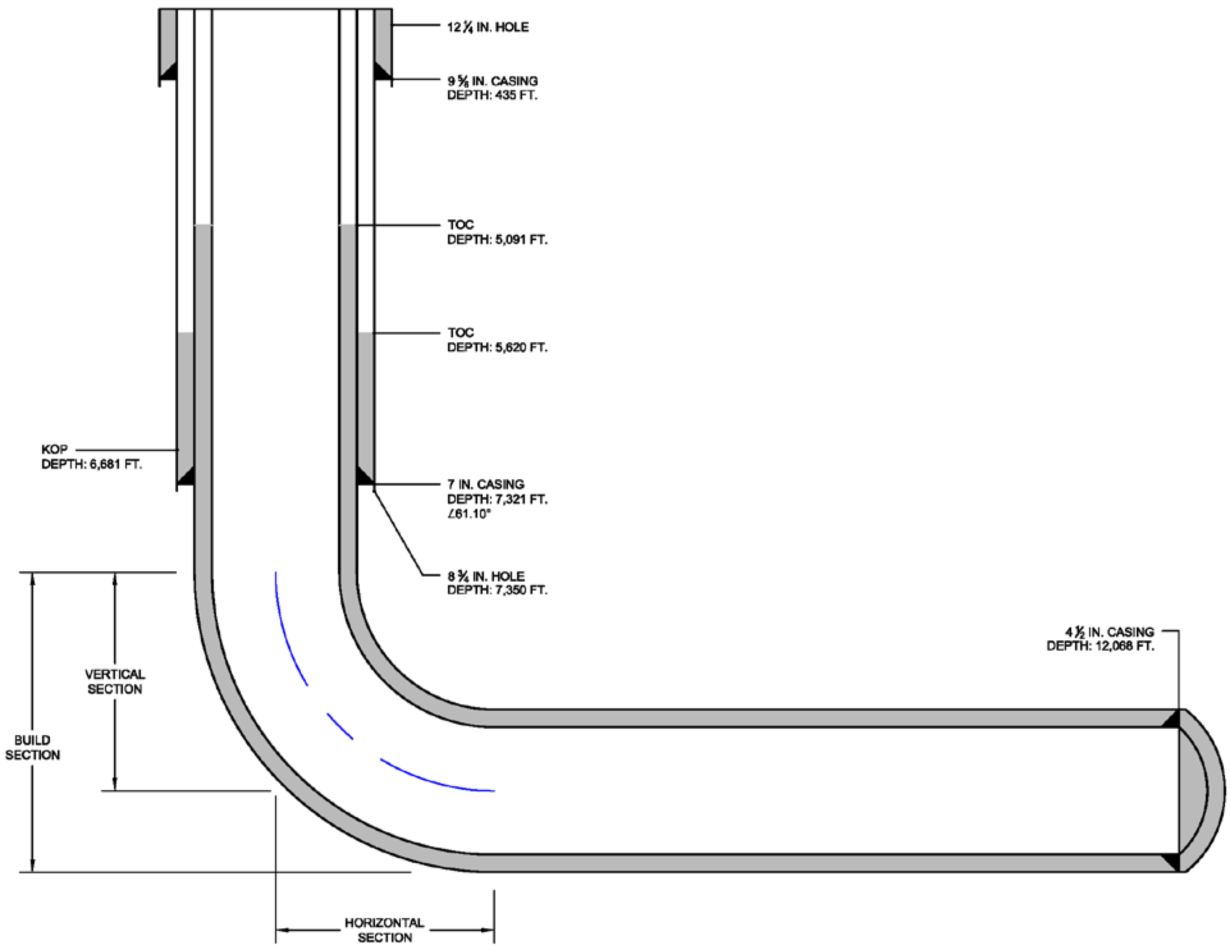

Figure 9 – Wellbore schematic after production casing is run and cemented.

9.8.4 Directional Drilling

Oil Company, Inc. implemented directional drilling operations on 21 June in the intermediate section of the hole. To put this operation in chronological perspective, cement was pumped on 20 June in an effort to resolve the afore-mentioned occurrence of lost circulation. The well depth at this time was 6,731 feet, md.

The directional drilling was to be performed with a rotary steerable system ("RSS"). On 21 June, the RSS system was run in the hole. On 22 June, the tools located the top of the cement plug at 6,416 feet. The cement was drilled from 6,416 feet to 6,669 feet when lost circulation was again encountered. This depth of 6,669 feet is similar to the depth of 6,731 feet where the first instance of loss of circulation occurred. Oil Company, Inc. added special loss additives at 18-20 pounds per barrel ("ppb") of mud. This effort appears to have resolved the issue until the casing was run. Drilling resumed at 6,669 feet. Recall the 7 inch casing was run to 7,350 feet on 26 June.

Oil Company, Inc. provided a list of the directional surveys taken as the well was being drilled. The list contained 98 data sets. Each data set includes the depth at which the survey was taken and recorded, the inclination which is the amount of hole angle deviation from a vertical position and the azimuth from a 0-360 degree basis from magnetic north. The data were entered in a commercial software package for further analysis.

In Figures 10, 11 and 12, the well path appears to be a smooth curve as shown in the section view, plan view and the 3D view. However, the dog-leg profile, or dog leg severity (Figure 13) indicates the curve is irregular, particularly over the interval of 6,500 feet to 8,000 feet.

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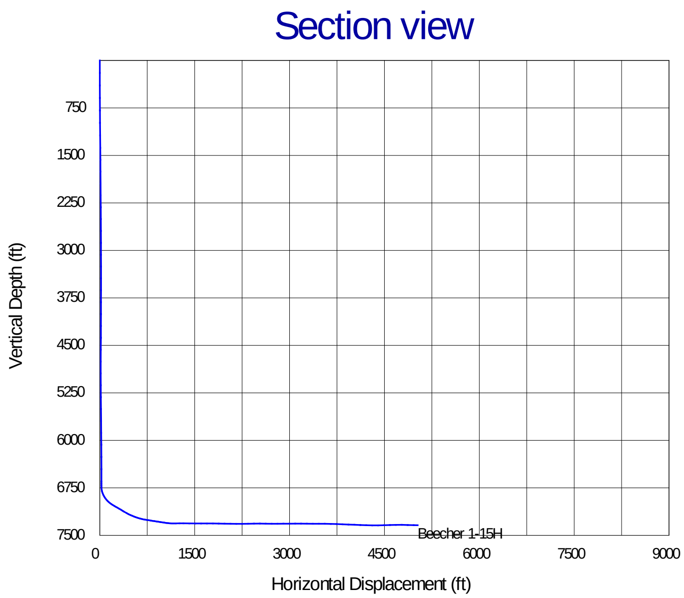

Figure 10 – Section view.

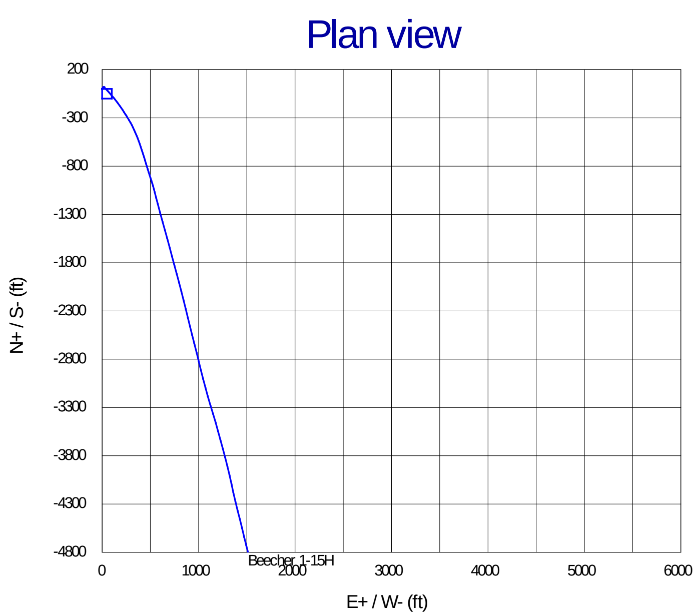

Figure 11 – Plan view.

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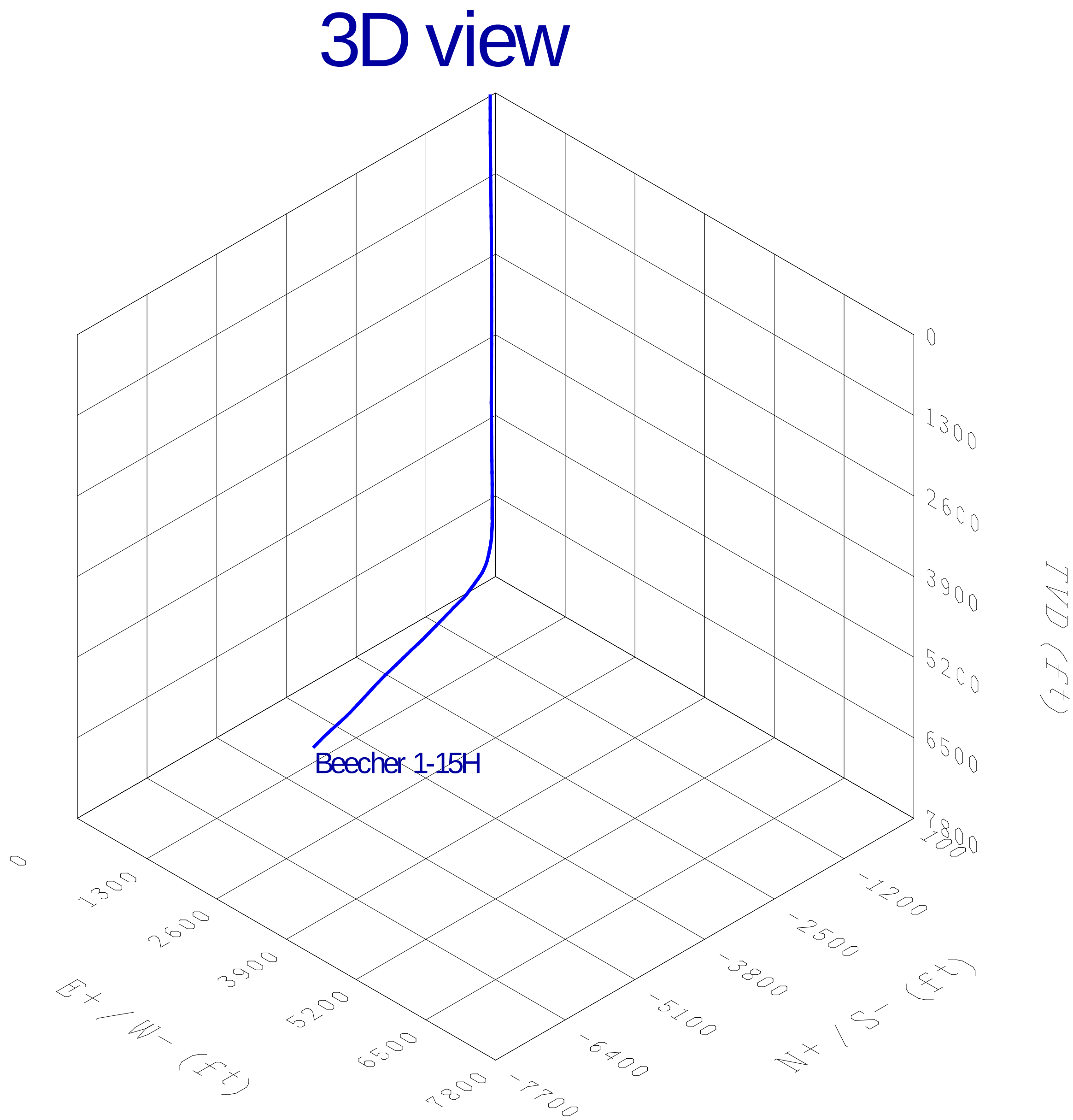

Figure 12 – 3-D view.

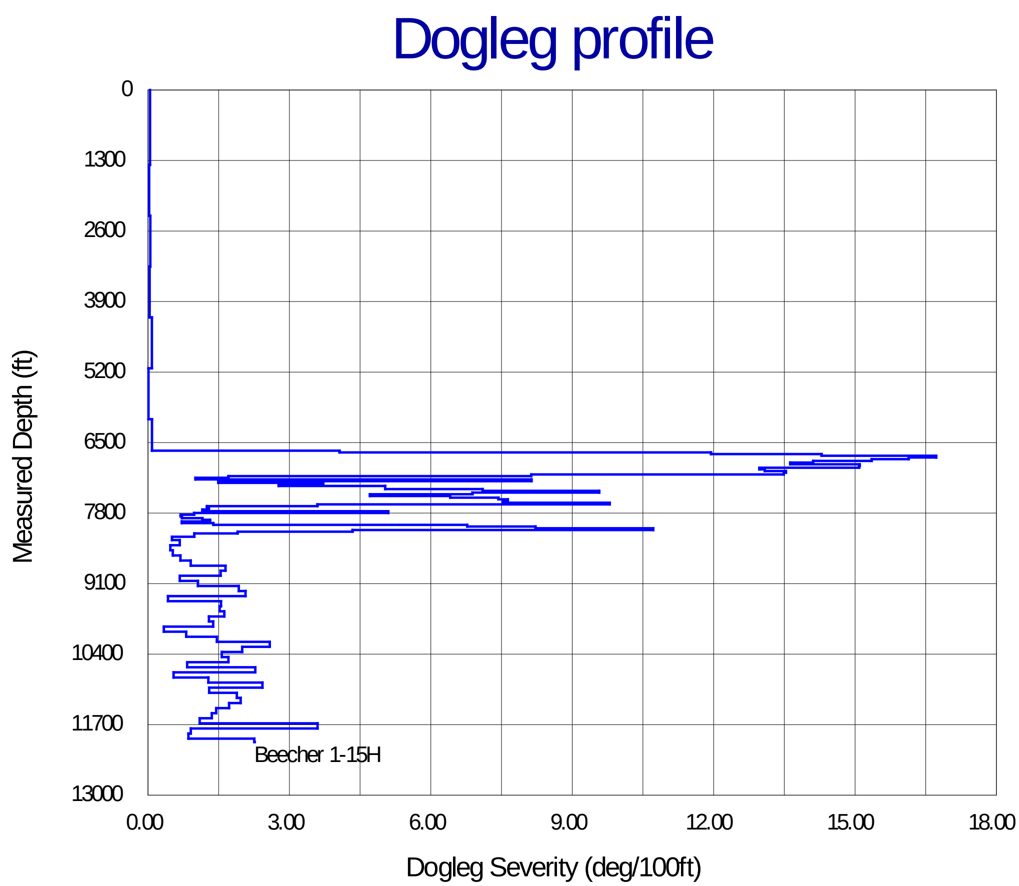

Figure 13 – Dogleg severity.

Dog-leg severity is a measure of the change in hole deviation over a specific length of the borehole. The typical measurement is deviation change over 100 feet of course length. Dog-leg angles in excess of 3-5 deg/100 feet should be avoided during drilling operations because of the increase in bending stress at each dog-leg. The dog-leg angles shown in Figure 6 range from 9-16 degrees. This measurement is of consequence because high dog-legs can substantially increase the pipe stresses. The import of stress changes is that the burst and/or collapse values can increase or decrease. Either over pull or compressional failure in the form of buckling could occur. The changes are known as the *bi-axial effects*. History has documented these types of failures.

The changes in tension/compression and burst/collapse can be calculated, although the effort is not trivial. Required input parameters are the pipe properties (burst/collapse ratings/a very large yield stress), the stress load in the pipe at the depth of the dog-leg and the magnitude of the dog-leg at that depth. At the time of this report, the location of the failure is unknown so the calculation can't be performed. If the calculation is made, it may provide guidance to the failure mode, i.e., stress overload.

9.8.5 Completion

On 15 July, 5 acid tanks and 10 frac tanks were moved to the location prior to initiating the completion. Fracture valves rated to 10,000 psi working pressure were installed on the well and tested. Flow manifolds were installed. The Service Provider moved its fracturing equipment to site.

Fracture Stage No. 1 was performed on 23 July (Figure 14). The initial step was to run a gun to perforate the interval of 11,826 feet to 12,021 feet. A total of 9,828 gallons of FE acid, which is 15% hydrochloric ("HCl"), were pumped. These perforations were fractured with 137,690 pounds of sand. The maximum treating pressure at the surface was 7,926 psi and the maximum rate was 95.2 bpm. The velocity of the fluids and sand in the 4.5 inch casing at 95.2 bpm is 102 feet per second ("ft/sec").

After the initial fracture stage was completed, an isolation packer was set in the casing to isolate future fracturing operations from the initial fracturing stage (Figure 15). Sequentially, as shown in Figure 16, the second set of perforations are made, fracturing operations for Stage 2 are completed and another isolation packer is set.

A casing failure of unknown cause(s) occurred while pumping the 15th fracturing stage (Figure 10). The Service Provider's treatment report shows a peak pressure of ~8500 psi at ~54 minutes into the pumping operation (Figure 17). It was provided to the operator as part of a larger post-treatment report. The complete report is shown at the end of this Appendix.

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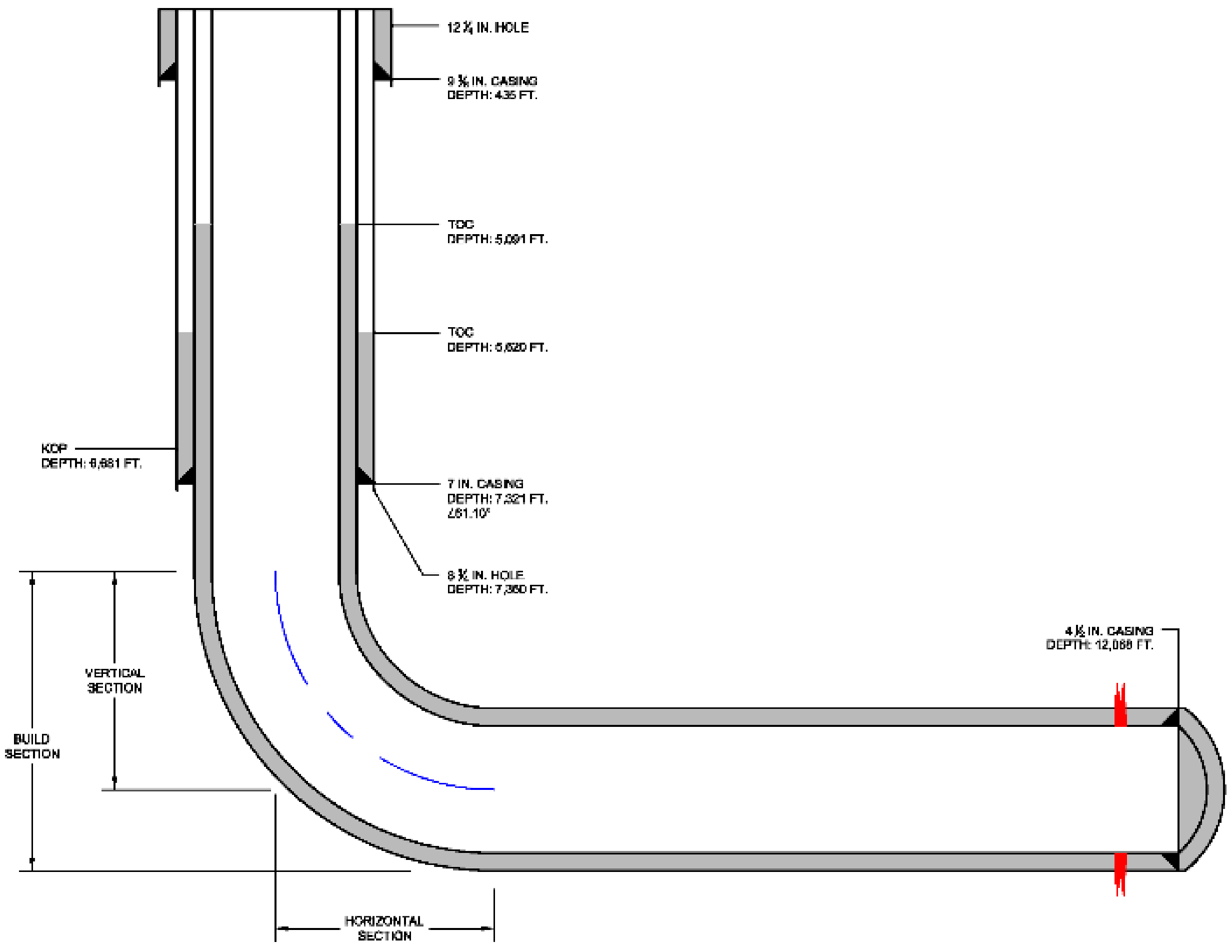

Figure 14 – Perforations for stage 1.

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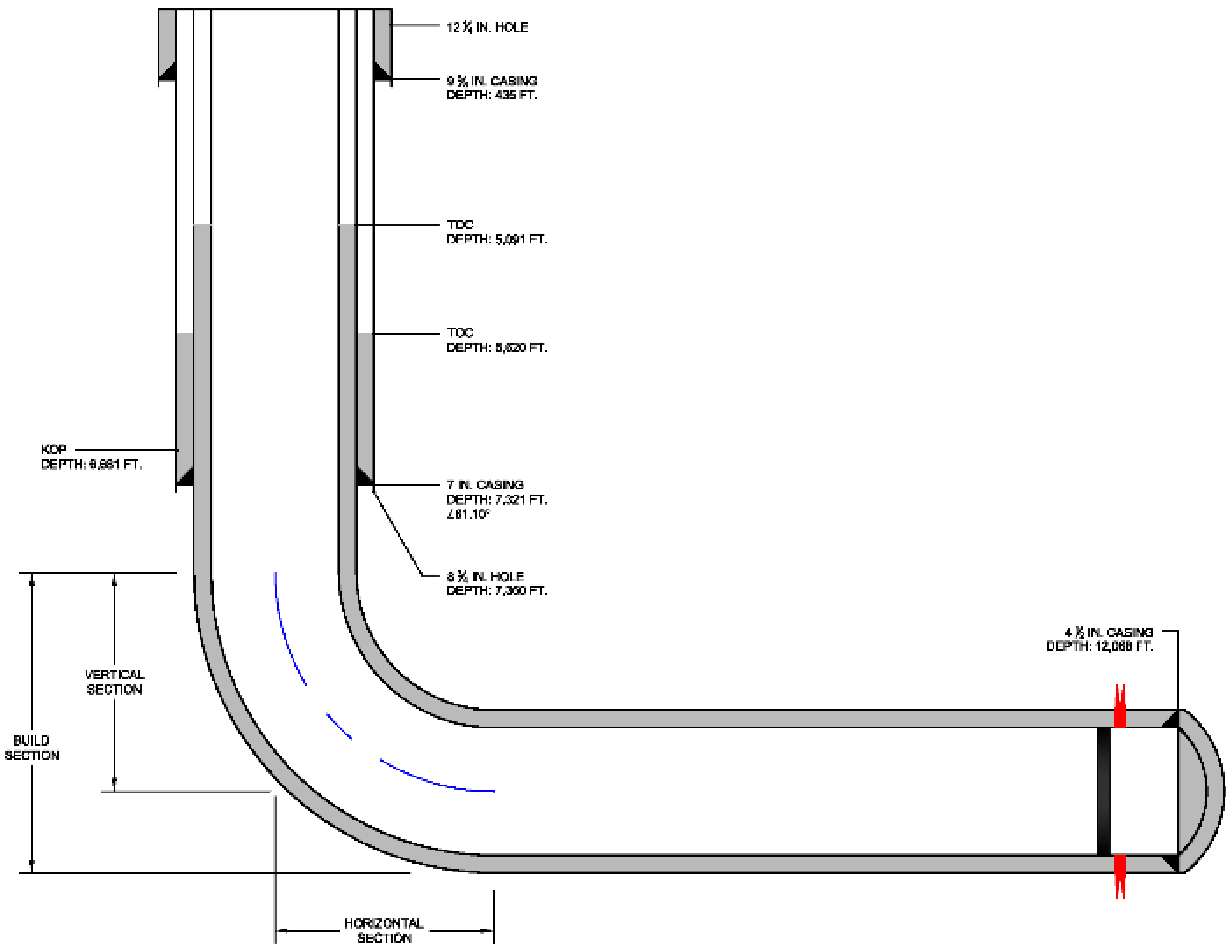

Figure 15 – Isolation packer set after stage 1 had been fractured.

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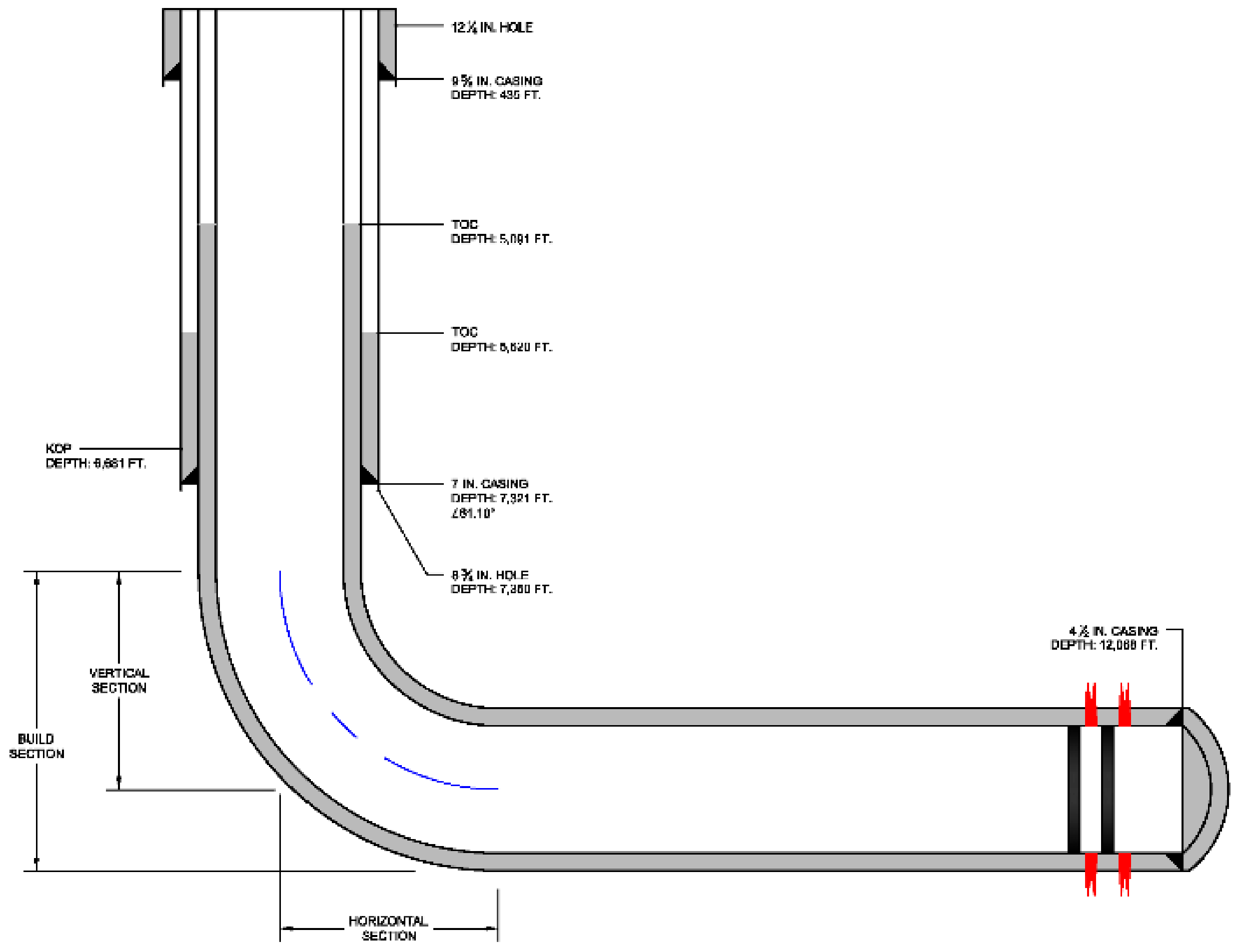

Figure 16 – Two stages have been completed.

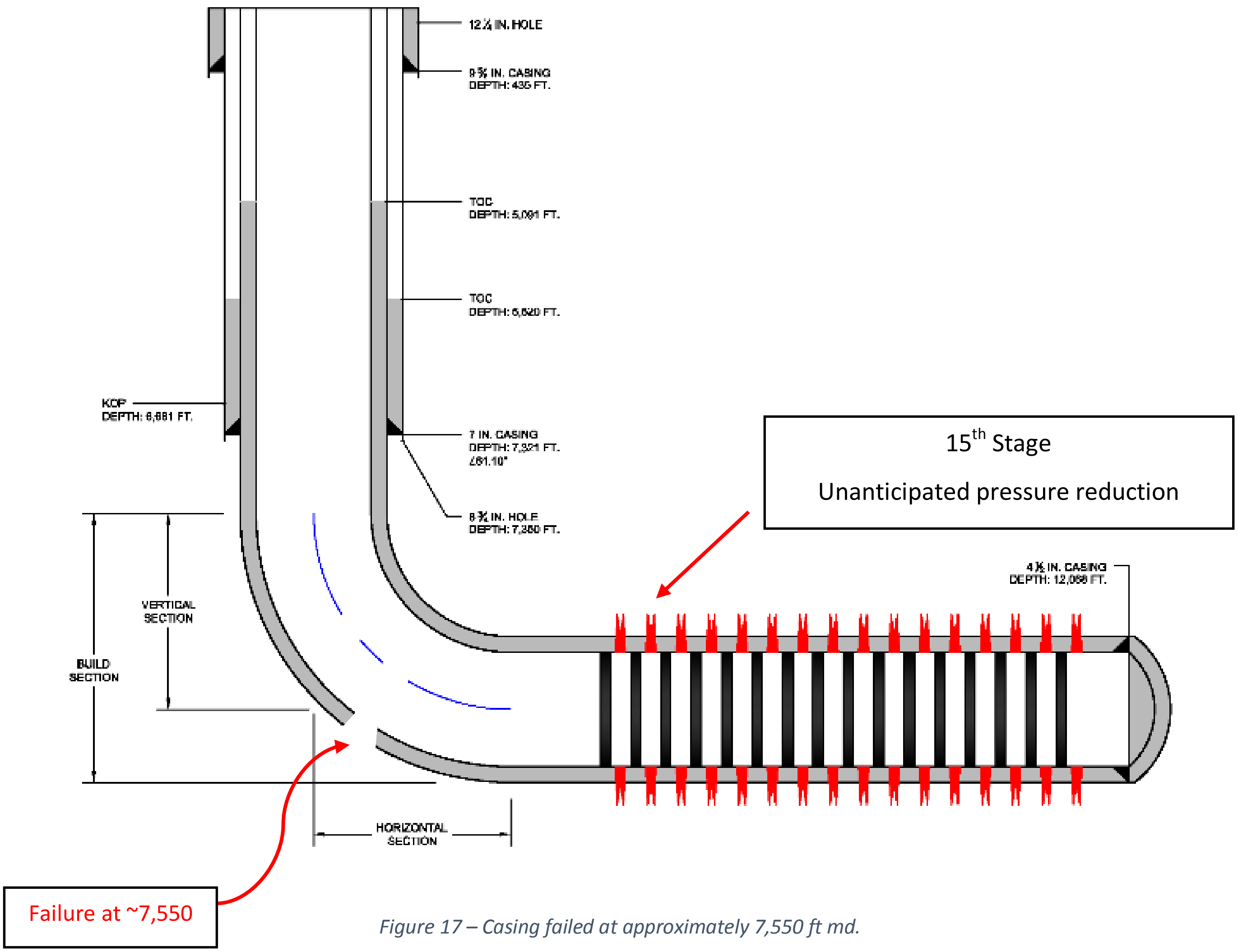

Figure 17 – Casing failed at approximately 7,550 ft md.

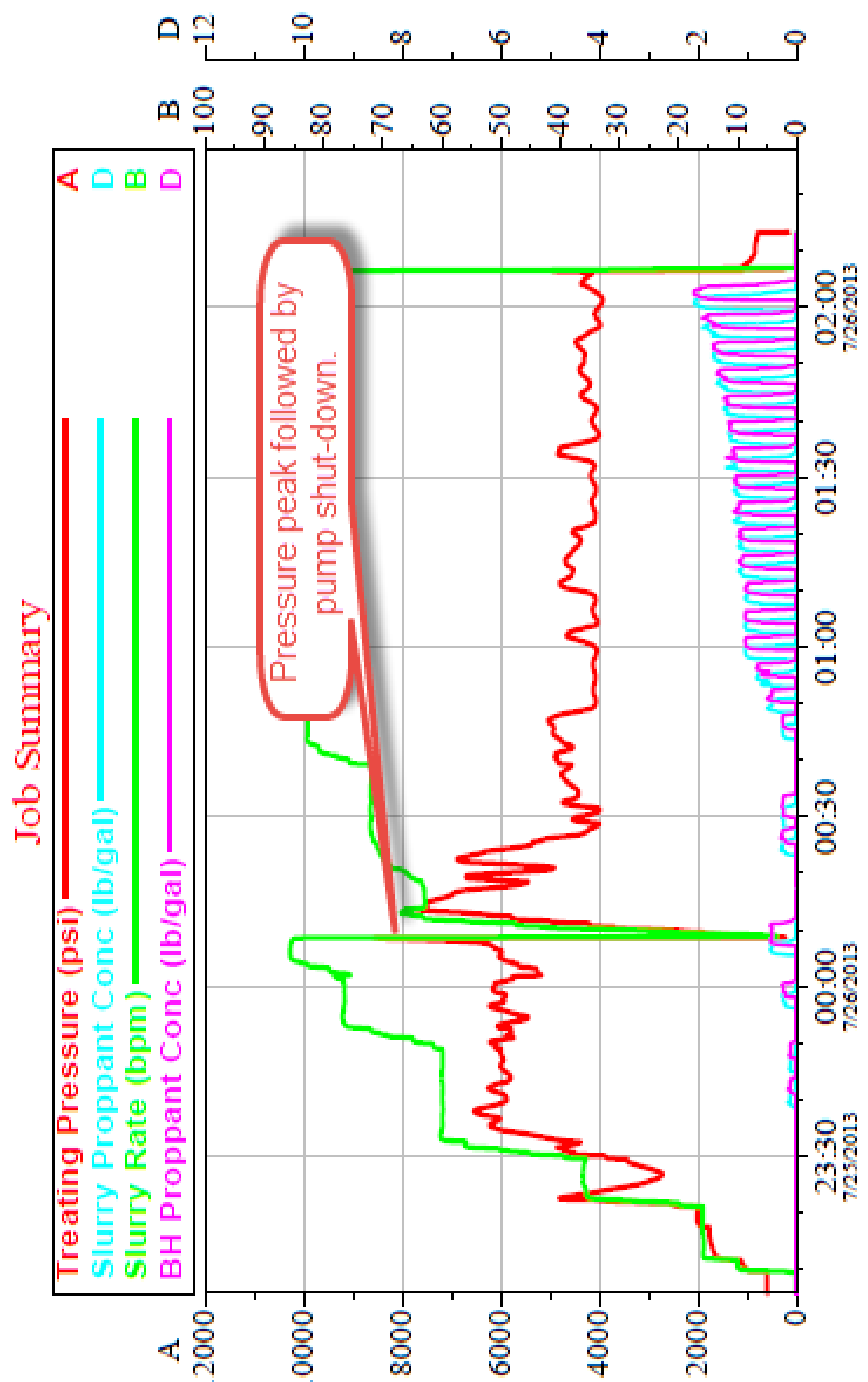

Figure 18 – Service provider's treatment pressure plot for the 15th stage.

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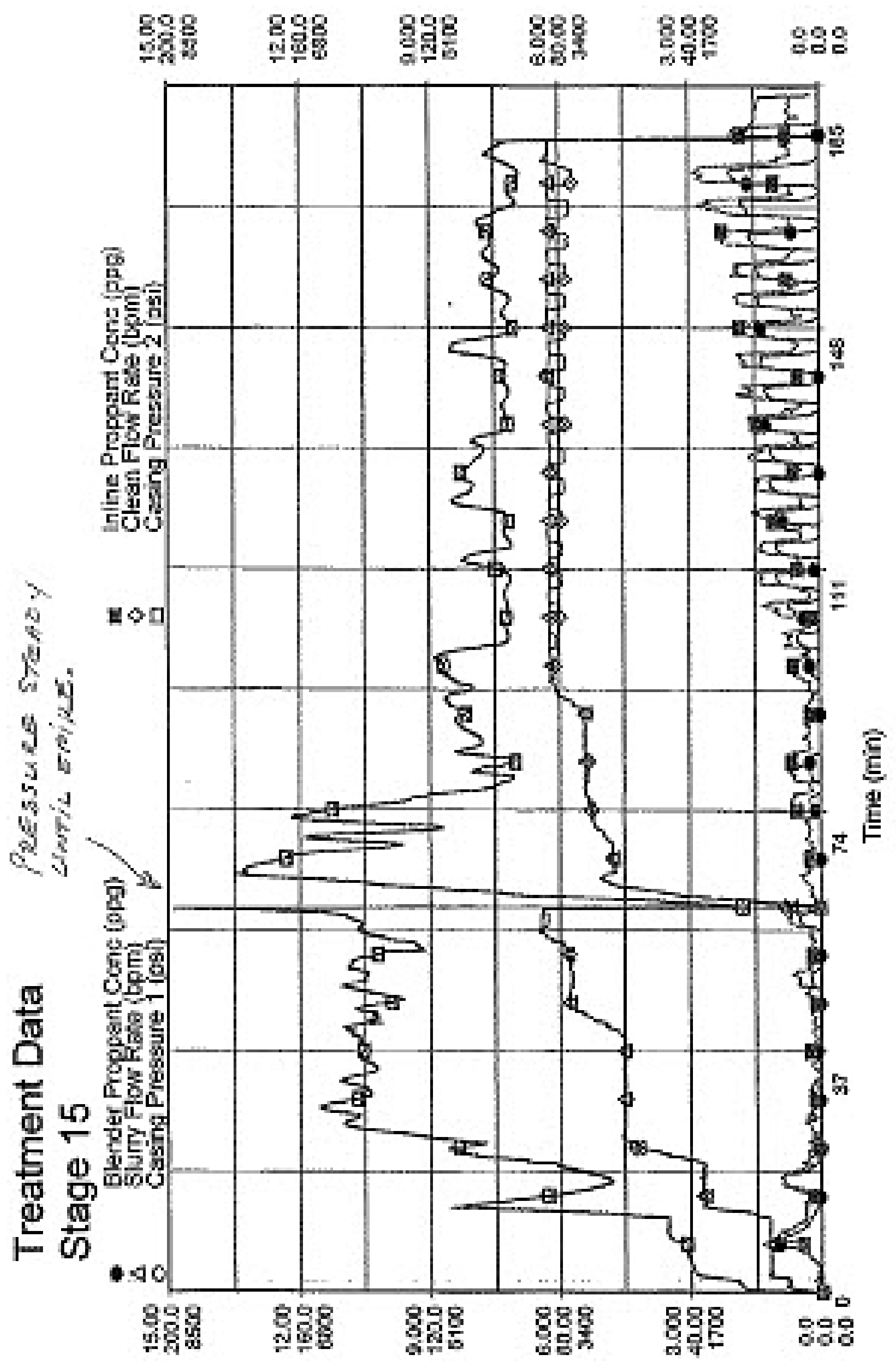

Figure 19 – Treatment pressure from a third-party quality assurance company.

An independent third-party quality control group hired by the Operator shows the pressure curve while pumping Stage 15. Figure 18 shows the pressure curve while pumping Stage 15. It more effectively shows the peak pressure and pump shut down than shown in Figure 19.

The frac pumps are equipped with an overpressure (auto-stop) feature when a maximum allowable pressure is observed. It appears the pumps were set to shut-down if the pressure exceeded 8,500 psi. At 00:08:44 hours on 26 July, the pumps were automatically shut down when the pressure reached 8550 psi and then restarted at 10:01 hours, or 77 seconds after the shut-down. The cause of the sudden increase in treating preasure may have been due to a phenomenon known as *sand out* but the available information provided by Oil Company, Inc. can't confirm or deny that the pressure spike to 8,550 psi resulted from a *sand out*. To assist in resolving the high pump pressures, Oil Company, Inc. added some chemicals, known as friction reducers, to lower the pumping friction pressures.

On 26 July, operations were underway to start the 16th stage. An obstruction was encountered at 8,072 feet when running in the hole with the perforation gun and the Service Provider's isolation packer. The wireline was pulled from the well. Two wellbore volumes of fluids were pumped at 95 bpm in an effort to remove any debris that may have caused the obstruction. The daily operations report on 27 July contains the reference "Possible hole in casing."

9.8.6 Post-Failure Analysis

Extensive efforts and calculations were made to identify the cause of the failure. Dog-leg bending stresses substantially increased the pipe tension but it did not exceed the pipe's tensile rating. Burst calculations indicate that the casing's published burst rating was not exceeded. Fluid flow rates inside the production casing were evaluated to investigate the possibility that erosion caused by the high velocity, sand-laden fluids may have occurred. Figure 20 clearly indicates that fluid velocities approached 100 ft/sec. Figure 20 also shows fluid velocities for other commonly used sizes of casing used during stimulation.

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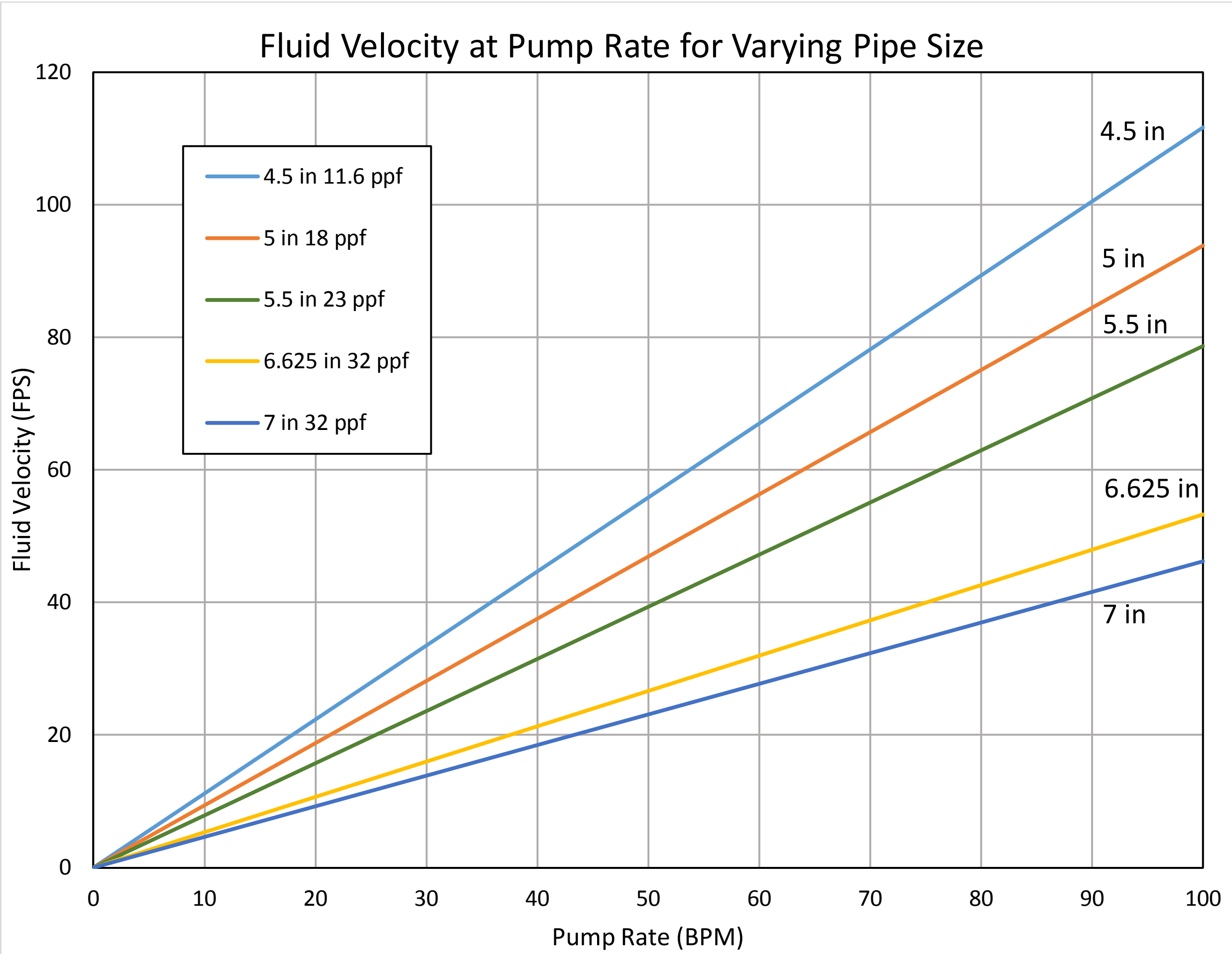


Figure 20 – Fluid velocities for various pump rates and casing sizes.

A review of Table 18 provides an informative insight into the conditions placed on casing design during a fracturing operation. The maximum treating pressure at the surface occurred during the 15th stage. It was 8,550 psi. The initial indicator of a hole problem was during the 15th stage. This observation might suggest that the pipe burst from Oil Company, Inc.'s over-pressurization of the pipe while pumping the 15th stage but pressure calculations proved this wasn't the case.

Further from Table 18, the weight of all of the sand pumped through the casing was 2,566,399 pounds. The maximum pump rate was 99.1 bpm. The total treating water was in excess of 4,500,000 gallons.

Table 21 – Well stimulation summary.

Summary of Fracture/Stimulation Jobs												
					Treated Water & Sand			Treated Water & Sand				
No.	Perforated Interval, ft	Pump Time, mins	Treated Water, gals	FE Acid, gals	Water, gals	Sand, lbs	Mesh	Water, gals	Sand, lbs	Mesh	Max. Pressure, psi	Max. Rate, bpm
1	11,826-12,035	245	336,432	9828	63,943	0		117,679	137,690	40/70	7926	95.2
2	11,627-11,793	151	271,193	9458	23,092	10,760	100	138, 454	157,340	40/70	7367	99.1
3	11,445-11,610	150	276,649	9576	139,134	172,160	40/70				8177	94.9
4	11,202-11,420	169	257,740	12,516	171,135	173,629	40/70				8289	83.6
5	11,035-11,167	145	230,078	9450	173,894	170,440	40/70				8239	92.4
6	10,860-11,010	148	286,738	6384	149,078	160,420	40/70				8128	96.5
7	10,632-10,842	137	234,338	9492	159,251	165,960	40/70				6939	93.2
8	10,297-10,590	151	288,025	9492	138,196	171,360	40/70	20,080	10,000	100	8223	93.4
9	10,043-10,273	179	309,333	12,776	158,266	122,180	40/70				8376	84.5
10	9845-9989	153	249,473	9568	163,614	170,560	40/70				8381	85.5
11	9700-9820	166	280,844	9870	159, 138	170,480	40/70				8430	85.5
12	9570-9678	143	325,918	9450	96,349	88,960	40/70				8205	97.7
13	9423-9552	127	228,384	9442	158,777	170,660	40/70				8172	95.6
14	9293-9406	N/A	259,531	9350	175,949	172,020	40/70				8415	90.5
15	9160-9282	368	294,618	9526	177,503	170,440	40/70				8550	85.6
16	9041-9138	163	226,737	10,568	160,315	171,340	40/70				8034	95.2
	TOTAL	2595	4,356,031	156,746	2,108,496	2261369		137,759	305,030			

TOTAL TREATING WATER, gals	**4,493,790**
TOTAL SAND,lbs	**2,566,399**
TOTAL ACID, gals	**156,746**

9.8.7 Production

Oil Company, Inc. made the decision after the 16th stage to place the well on production to generate a revenue stream from the flowing oil and gas. A 2-7/8 inch tubing string was run on 14 August. It contained gas lift valves and a packer. Separation and treating equipment was delivered to the site and installed. The initial oil production occurred on 30 August and the well is believed to be producing as of this date. Figure 21 shows Oil Company, Inc.'s Oil Well No. 1 1-15H well as drilled and completed. After the 16th stage was completed, Oil Company, Inc. was unsuccessful at attempts to run the guns for the 17th stage. Operations were terminated.

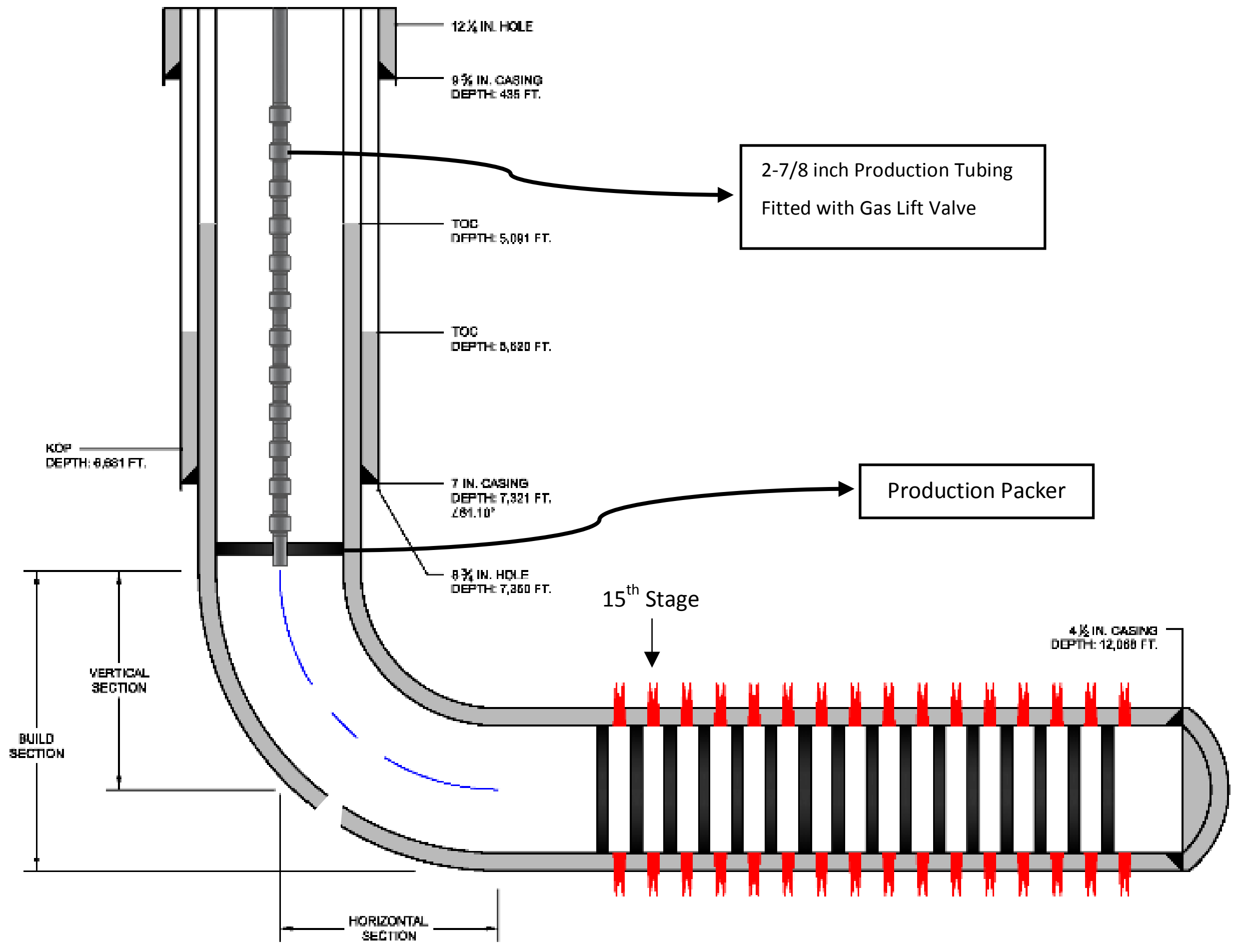


Figure 21 – Casing failed at approximately 7,550 ft md.

9.8.8 Post-Treatment Report

Within a few days of completing stimulations, the service provider for stimulation prepares separate reports or each frac stage. Typically, these reports are comprehensive. The service provider for Oil Well No. 1 prepared the following report.

Oil Company, Inc
1000 Company Address
Somewhere, USA

Oil Well No. 1

Interval 15 (9160’-9282’)
Somewhere, USA

Sales Order: 000000000

Post Job Report

For: John Doe
Date: Thursday, January 1, 2015

SERVICE COMPANY LOGO

Table of Contents

1.0 EXECUTIVE SUMMARY

John Doe
OIL COMPANY, INC
1000 Company Address
Somewhere, USA

Dear John Doe,

Service Company appreciates the opportunity to perform the stimulation treatment on Oil Well No.1. A pre-job safety meeting was held where details of the job were discussed, potential safety hazards were reviewed, and environmental compliance procedures were outlined. Pump time was 368.32 min.

The proposed treatment for Oil Well No. 1 Stage 15 consisted of:

- 223260 gal of Treated Water.
- 9450 gal of FE ACID - SBM (341772).
- 152600 gal of Treated Water carrying 170400 lb of SAND - PREMIUM - 40/70.

The treatment actually pumped consisted of:

- 294618 gal of Treated Water.
- 9526 gal of FE ACID - SBM (341772).
- 177503 gal of Treated Water carrying 170440 lb of SAND - PREMIUM - 40/70.

The total liquid load to recover is 14305 bbl.
The max treating pressure was 8550 psi and the max rate was 85.6 bpm.
The average treating pressure was 4539 psi and the average rate was 82.8 bpm.
100% of the designed proppant was pumped.

During pump down for wireline, we had issues. We attempted to pump down 6 times, and on the last run, we got all gun to fire, and the plug to set. The pump down volume was 2165 bbl's, and the job was resumed fracking Stage 16.

Service Company is strongly committed to quality control on location. Before and after each job all chemicals, proppants, and fluid volumes are measured to assure the highest level of quality control. Tank fluid analysis, crosslink time, and break tests are performed before each job in order to optimize the performance of the treatment fluids.

Service Company maintains a continuous quality improvement process and appreciates any comments or suggestions that you may have. Halliburton again thanks you for the opportunity to perform service work on this well. We hope to be your solutions provider for future projects.

Respectfully,

Jane Rhoe

2.0 Well Information

2.1 Customer Information

Customer	OIL COMPANY, INC.
Sales Order	000000000
Well Name	Oil Well No.1
Interval	15
Well Number	1-15H
Job Date	1-Jan-15
County	County
State	State
UWI/API	00-000-00000
Lease Name	Lease
Country	United States of America
H2S Present	Unknown
CO2 Present	Unknown
Customer Representative	John Doe
Customer Telephone Number	000-000-000
Halliburton Representative	Jane Rhoe

2.2 Pipe Information

Equipment	Top MD ft	Bottom MD ft	Top TVD ft	Bottom TVD ft	OD in	ID in	Grade	Weight lb/ft
Casing	0.0	12068.0	0.0	7861.8	4.500	4.000	P-110	11.60

2.3 Perforation Intervals

Top MD ft	Bottom MD ft	Top TVD ft	Bottom TVD ft	Number of Shots	Perf Density spf	Perf Phasing °	Perf Diameter in
9160.0	9282.0	7226.1	7273.5	48	4	60	0.420

3.0 Performance Highlights

3.1 Treatment Summary

Treatment # 15

Start Time			23:09:00	hr
End Time			2:07:00	hr
Pump Time			2:58:00	hr
Pressure Test			9425	psi
Starting Pressure			588	psi
Breakdown Pressure @	15.7	bpm	1999	psi
Max. Treating Pressure			8550	psi
Avg. Treating Pressure			4539	psi
Max. Slurry Rate			85.6	bpm
Avg. Slurry Rate			82.8	bpm
Job Clean Volume			12144	bbl
Job Slurry Volume			12330	bbl
Load To Recover			14305	bbl
Total Well Load to Recover			150345	bbl
Pumpdown Volume			2161	bbl
Pad Volume (gal)			294618	gal
Recycled Water			0	bbl
Avg. HHP			9212	HP
Final ISIP			1110	psi
Five Minute ISIP			802	psi
Final F. G.			0.59	psi/ft
Proppant Type	Common White 100 Mesh		0	lbs
Proppant Type	Premium White 40/70		170440	lbs
Total Proppant Pumped			170440	lbs
Percent of Designed Proppant			100.02	%
Max Proppant Concentration			2.07	lb/gal
Avg. Proppant Concentration			0.60	lb/gal
Proppant in Wellbore			0	lbs
Proppant in Formation			170440	lbs
Optikleen WF			495	lbs
FR-66			755	gal
HAI-404M			0	gal
Scale LP-65			74	gal
LoSurf 300D			260	gal
BE-9			127	gal
FE 1			0	gal
FE 2			0	gal

Disclaimer: The average and maximum values (except volumes and bottom hole values) are based on the start and end averaging times.

3.2 Job Event Log

Time	Description	Comment	Treating Pressure psi	Job Clean Vol gal	Job Slurry Vol gal	Job Proppant lb
25-Jul-13 22:36:45	Start Job	Starting Job				
23:01:18	Pressure Test	Pressure Test to 9425 psi	9416	1699	1699	0
23:09:43	Stage 1	Breakdown	607	1	1	0
23:09:44	Start Averaging	Start Avg Trt 1	609	2	2	0
23:13:52	Stage 2	Acid	1690	2115	2115	0
23:20:00	Stage 3	Pad	1998	6170	6170	0
23:20:55	Ball on Seat	Ball on Seat @ 1761 psi, 15.7 bpm, 111 bbl's	1996	6777	6777	0
23:22:37	Other	3150 gal 15% HCl on Perfs	4793	8366	8366	0
23:24:29	Stage 4	Acid	3612	11138	11138	0
23:28:35	Stage 5	Pad	3222	17311	17311	0
23:31:42	Other	6300 gal 15% HCl on Perfs	4845	22804	22804	0
23:38:33	Stage 6	Proppant Laden Fluid	6428	39816	39816	0
23:41:43	Stage 7	Pad	6160	47726	47762	794
23:44:56	Stage 8	Proppant Laden Fluid	5881	55777	55813	794
23:48:07	Stage 9	Pad	5986	63772	63844	1600
23:53:27	Other	Decreased FR-66 to 1.5 gal/Mgal	5978	78592	78664	1600
23:54:25	Other	Decreased FR-66 to 1.25 gal/Mgal	5468	81759	81831	1600
23:56:24	Stage 10	Proppant Laden Fluid	6161	88093	88166	1604
23:58:55	Stage 11	Pad	5962	96089	96246	3471
26-Jul-13 00:04:43	Other	Decreased FR-66 to 1.00 gal/Mgal	5902	115195	115356	3560
00:05:43	Stage 12	Proppant Laden Fluid	6008	118742	118904	3578
00:08:09	Stage 13	Pad	6827	127309	127645	7414
00:08:44	Other	Kicked Out due to Pressure	3825	129382	129722	7504
00:10:01	Other	Increased FR-66 to 1.5 gal/Mgal	2374	130310	130650	7504
00:13:34	Other	Increased FR-66 to 1.75 gal/Mgal	7489	138439	138779	7504
00:33:43	Other	Decreased FR-66 to 1.5 gal/Mgal	4438	196136	196703	12537
00:34:44	Other	Decreased FR-66 to 1.25 gal/Mgal	4425	199208	199776	12537
00:48:34	Stage 14	Proppant Laden Fluid	4537	244381	245051	14795
00:50:54	Stage 15	Pad	4068	252338	253179	18583
00:53:12	Stage 16	Proppant Laden Fluid	4105	260371	261217	18680
00:55:36	Stage 17	Pad	4086	268440	269536	24201
00:57:54	Stage 18	Proppant Laden Fluid	4100	276461	277568	24452
01:00:17	Stage 19	Pad	4099	284431	285889	32179
01:02:34	Stage 20	Proppant Laden Fluid	4627	292389	293859	32465
01:05:57	Stage 21	Pad	4107	303856	305665	39942

Time	Description	Comment	Treating Pressure psi	Job Clean Vol gal	Job Slurry Vol gal	Job Proppant lb
01:07:29	Stage 22	Proppant Laden Fluid	4100	309225	311034	39942
01:09:53	Stage 23	Pad	4291	317276	319410	47125
01:12:18	Stage 24	Proppant Laden Fluid	4632	325679	327830	47495
01:14:42	Stage 25	Pad	4651	333648	336183	55974
01:17:01	Stage 26	Proppant Laden Fluid	4544	341658	344212	56389
01:19:24	Stage 27	Pad	4386	349628	352563	64813
01:21:43	Stage 28	Proppant Laden Fluid	4191	357642	360586	65025
01:24:07	Stage 29	Pad	4080	365609	368958	73958
01:26:26	Stage 30	Proppant Laden Fluid	4127	373682	377052	74415
01:28:52	Stage 31	Pad	4087	381755	385542	83620
01:31:11	Stage 32	Proppant Laden Fluid	4139	389836	393638	83947
01:33:38	Stage 33	Pad	4562	397938	402186	93798
01:35:57	Stage 34	Proppant Laden Fluid	4494	405987	410255	94250
01:38:22	Stage 35	Pad	4032	413977	418695	104180
01:40:37	Stage 36	Proppant Laden Fluid	4131	421798	426530	104494
01:42:50	Stage 37	Pad	4083	429108	434265	113895
01:45:11	Stage 38	Proppant Laden Fluid	4327	437249	442465	115168
01:47:34	Stage 39	Pad	4249	445033	450764	126558
01:49:59	Stage 40	Proppant Laden Fluid	4340	453434	459207	127489
01:52:22	Stage 41	Pad	4310	461175	467500	139653
01:54:39	Stage 42	Proppant Laden Fluid	4381	469126	475485	170440
02:03:51	Stage 43	Flush	4252	499742	507563	170440
02:14:39	Stage 44	Pump-In	34	510059	517880	170440
03:03:24	Pause	Suspending Job	0	510059	517880	170440
05:27:25	Resume	Resuming Job	30	510059	517880	170440
06:26:59	Pause	Suspending Job	0	512405	520226	170440
06:37:24	Resume	Resuming Job	437	512405	520226	170440
08:40:29	Pause	Suspending Job	0	554768	562589	170440
10:04:19	Resume	Resuming Job	436	554768	562589	170440
11:17:18	Pause	Suspending Job	0	570124	577945	170440
13:09:20	Resume	Resuming Job	0	570124	577945	170440
13:54:55	Pause	Suspending Job	0	576982	584803	170440
15:16:13	Resume	Resuming Job	352	576982	584803	170440
18:16:50	End Averaging	End Avg Trt 1	401	600785	608606	170440
18:16:55	End Job	Ending Job	401	600785	608606	170440

4.0 ACTUAL STAGE SUMMARY

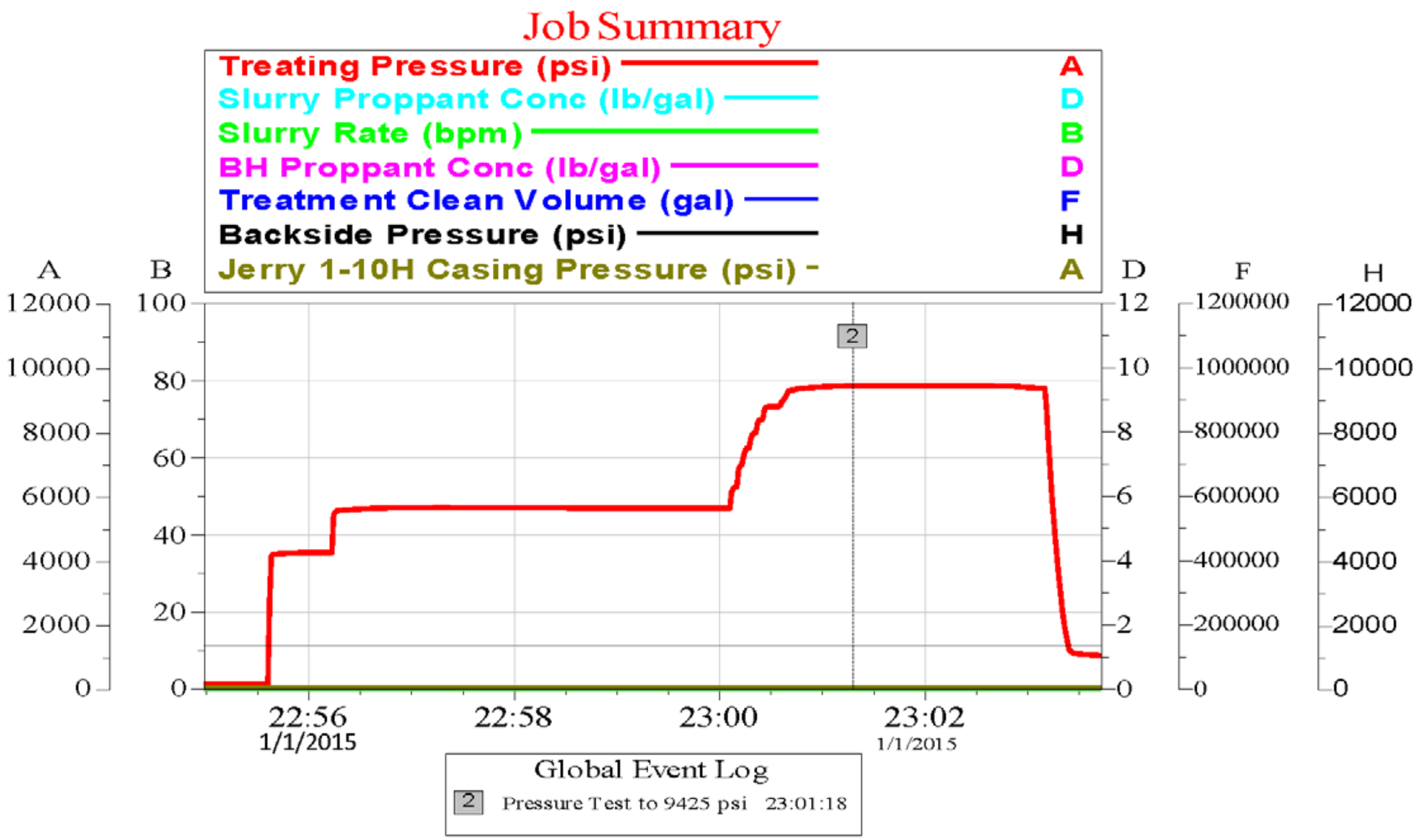
4.1 Stage Summary

Stage Number	Avg Treating Pressure psi	Avg Slurry Rate bpm	Clean Volume gal	Slurry Volume gal	Avg Slurry Prop Conc lb/gal	Prop Mass lb
1	1326	12.1	2115	2115	0.00	0
2	1837	15.7	4056	4056	0.00	0
3	3293	26.4	4968	4968	0.00	0
4	2985	36.0	5470	5470	0.00	0
5	5179	53.7	22505	22505	0.00	0
6	6011	59.8	7911	7946	0.11	794
7	5975	59.8	8051	8051	0.00	0
8	5960	59.8	7995	8031	0.11	806
9	5889	70.0	24321	24322	0.04	4
10	5999	76.4	7996	8081	0.23	1867
11	5780	79.3	22652	22657	0.05	107
12	6149	85.5	8568	8742	0.45	3836
13	5137	69.2	117071	117406	0.23	7381
14	4154	82.9	7957	8128	0.48	3789
15	4101	83.0	8033	8037	0.15	97
16	4082	83.0	8069	8319	0.68	5520
17	4109	83.1	8021	8033	0.12	251
18	4063	83.1	7970	8320	0.97	7727
19	4429	83.0	7957	7970	0.36	286
20	4194	83.0	11467	11806	0.88	7477
21	4121	83.2	5369	5369	0.00	0
22	4107	83.1	8050	8376	0.91	7183
23	4675	82.9	8404	8420	0.29	370
24	4565	82.8	7968	8352	1.06	8480
25	4638	82.9	8010	8029	0.33	415
26	4431	82.9	7969	8351	1.06	8424
27	4428	83.0	8014	8024	0.31	212
28	4087	83.0	7967	8372	1.12	8934
29	4125	83.2	8073	8094	0.12	456
30	4076	83.1	8073	8490	1.14	9205
31	4143	83.2	8081	8096	0.36	327
32	4184	83.0	8102	8548	1.22	9850
33	4749	82.9	8049	8070	0.16	452
34	4106	83.0	7990	8440	1.24	9931
35	4112	83.2	7821	7835	0.39	314
36	4073	83.1	7309	7735	1.30	9401

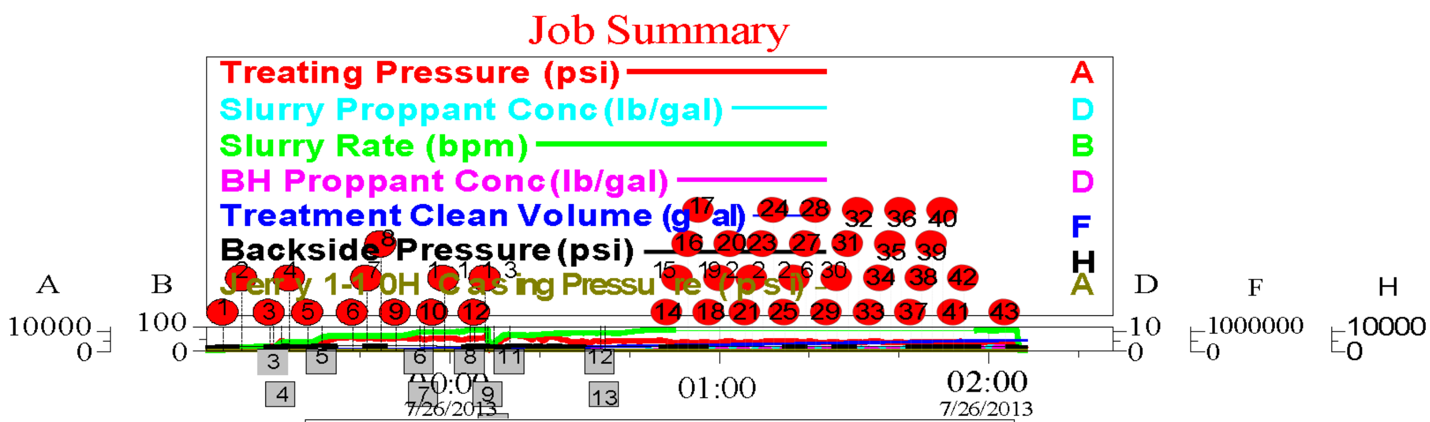
Stage Number	Avg Treating Pressure psi	Avg Slurry Rate bpm	Clean Volume gal	Slurry Volume gal	Avg Slurry Prop Conc lb/gal	Prop Mass lb
37	4268	83.1	8142	8199	0.42	1272
38	4221	82.9	7784	8299	1.46	11390
39	4349	83.1	8401	8443	0.39	931
40	4299	82.9	7742	8292	1.57	12164
41	4412	83.0	7951	7986	0.45	766
42	4061	83.0	30616	32078	1.45	32281
43	3881	76.2	10317	10317	0.00	0
44	862	11.3	90726	90726	0.00	0
Total			600785	608606		170440

5.0 Attachments

5.1 Pressure Test Stage 15



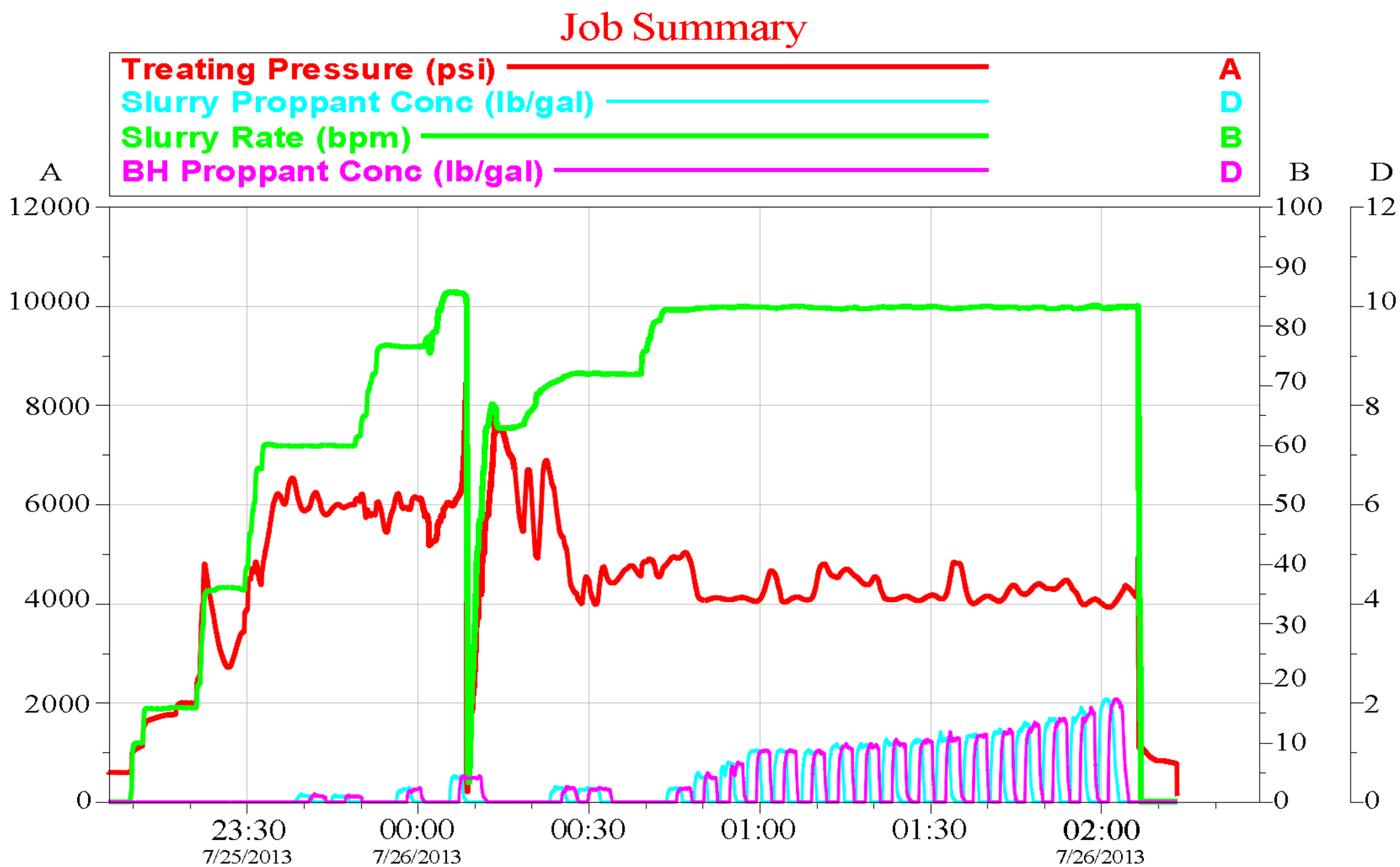
5.2 Event Summary Stage 15



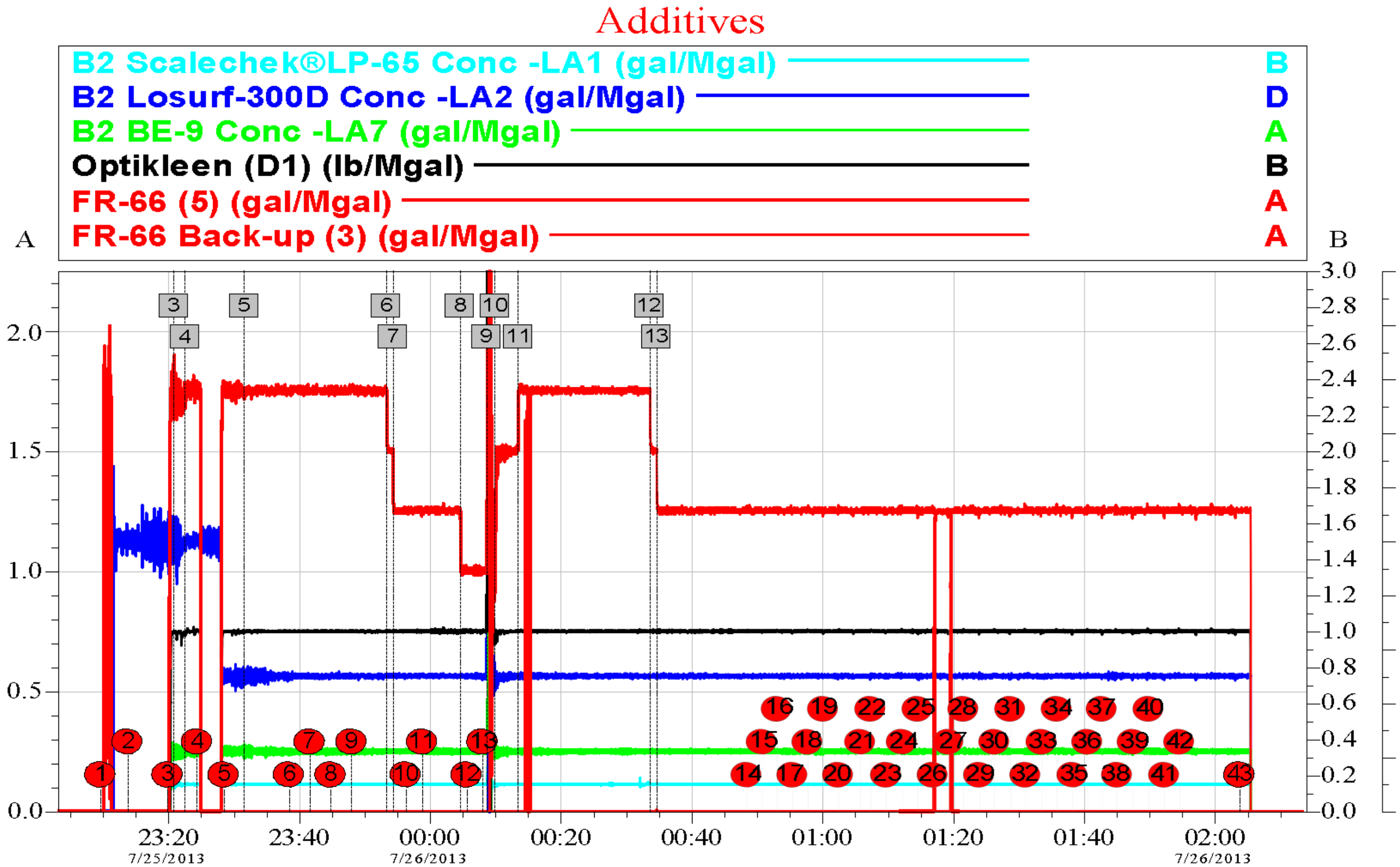
Global Event Log

3	Ball on Seat @ 1761 psi, 15.7 bpm, 111 bbl's	7/25/2013 23:20:55
4	3150 gal 15% HCl on Perfs	7/25/2013 23:22:38
5	6300 gal 15% HCl on Perfs	7/25/2013 23:31:42
6	Decreased FR-66 to 1.5 gal/Mgal	7/25/2013 23:53:27
7	Decreased FR-66 to 1.25 gal/Mgal	7/25/2013 23:54:26
8	Decreased FR-66 to 1.00 gal/Mgal	7/26/2013 00:04:44
9	Kicked Out due to Pressure	7/26/2013 00:08:45
10	Increased FR-66 to 1.5 gal/Mgal	7/26/2013 00:10:01
11	Increased FR-66 to 1.75 gal/Mgal	7/26/2013 00:13:34
12	Decreased FR-66 to 1.5 gal/Mgal	7/26/2013 00:33:43
13	Decreased FR-66 to 1.25 gal/Mgal	7/26/2013 00:34:44

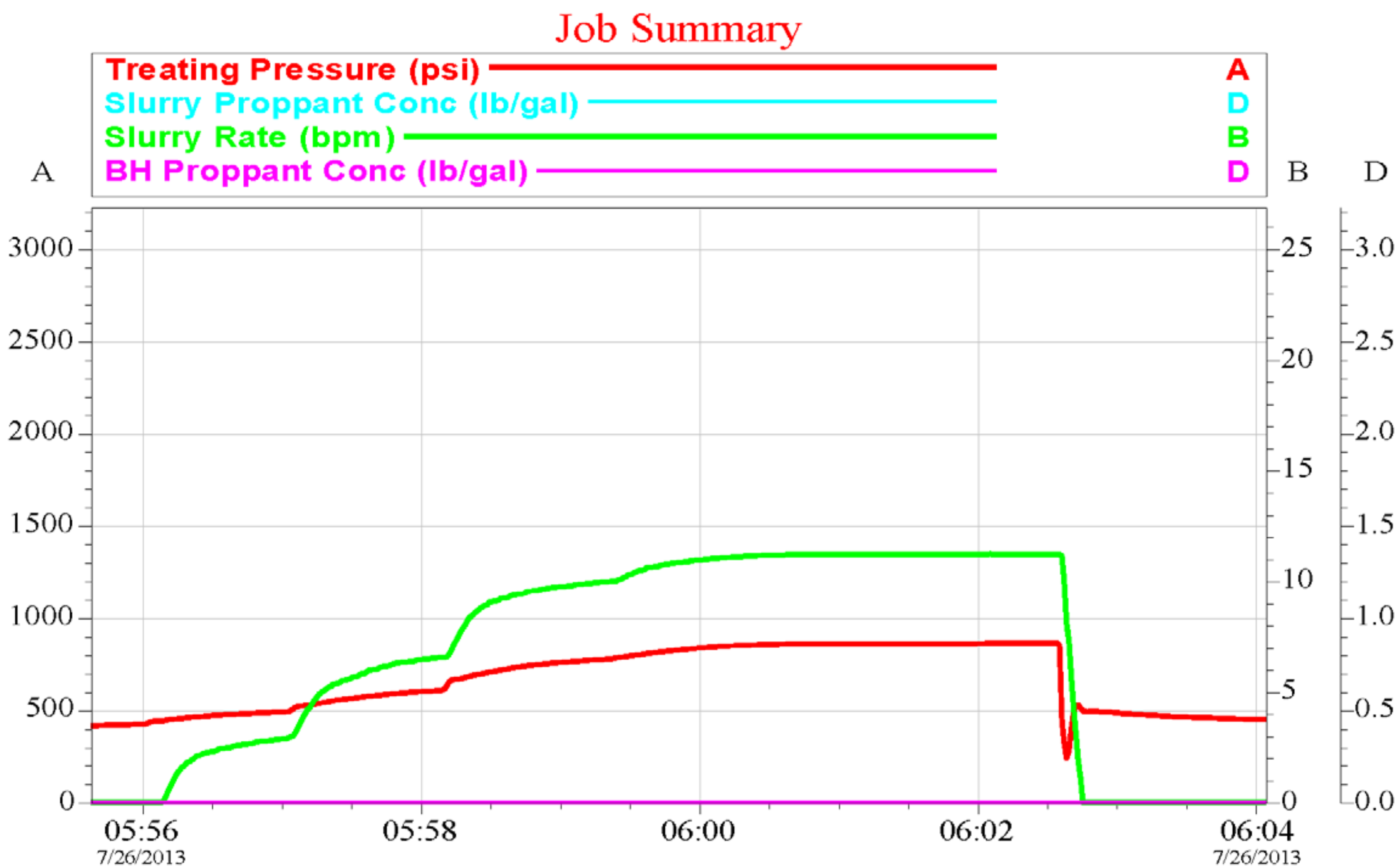
5.3 Job Summary Stage 15



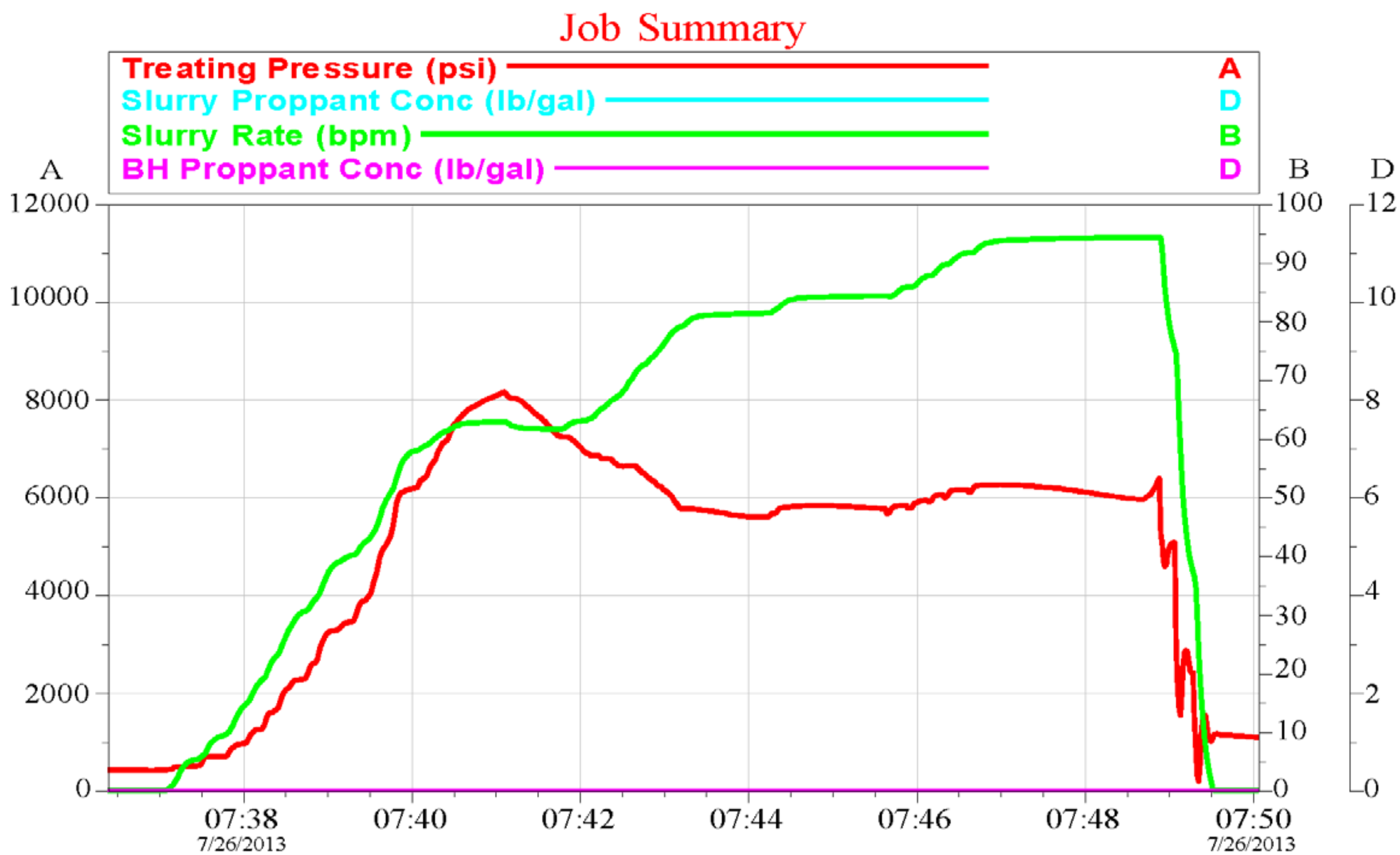
5.4 Additives Stage 15



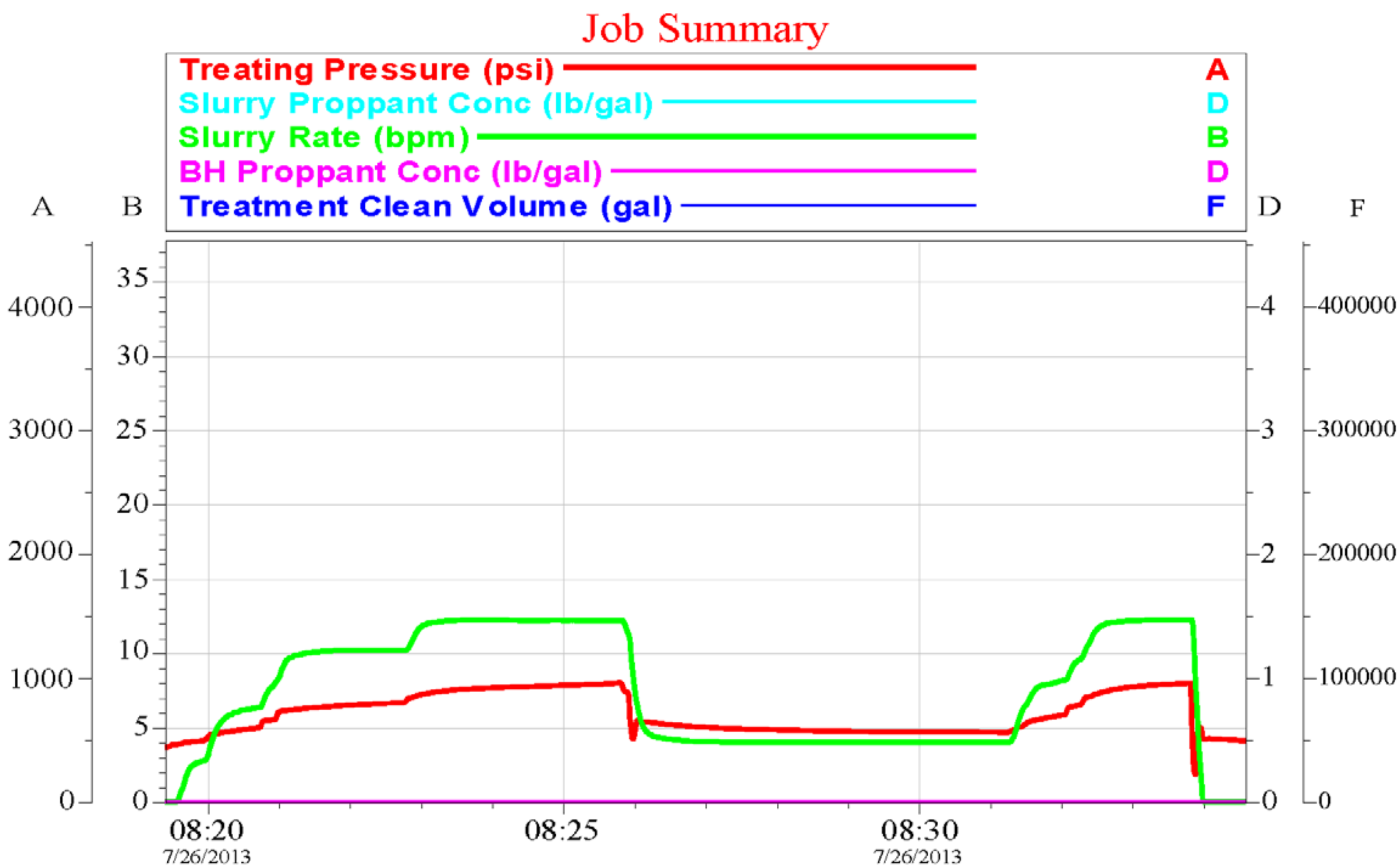
5.5 Pump Down After Stage 15a



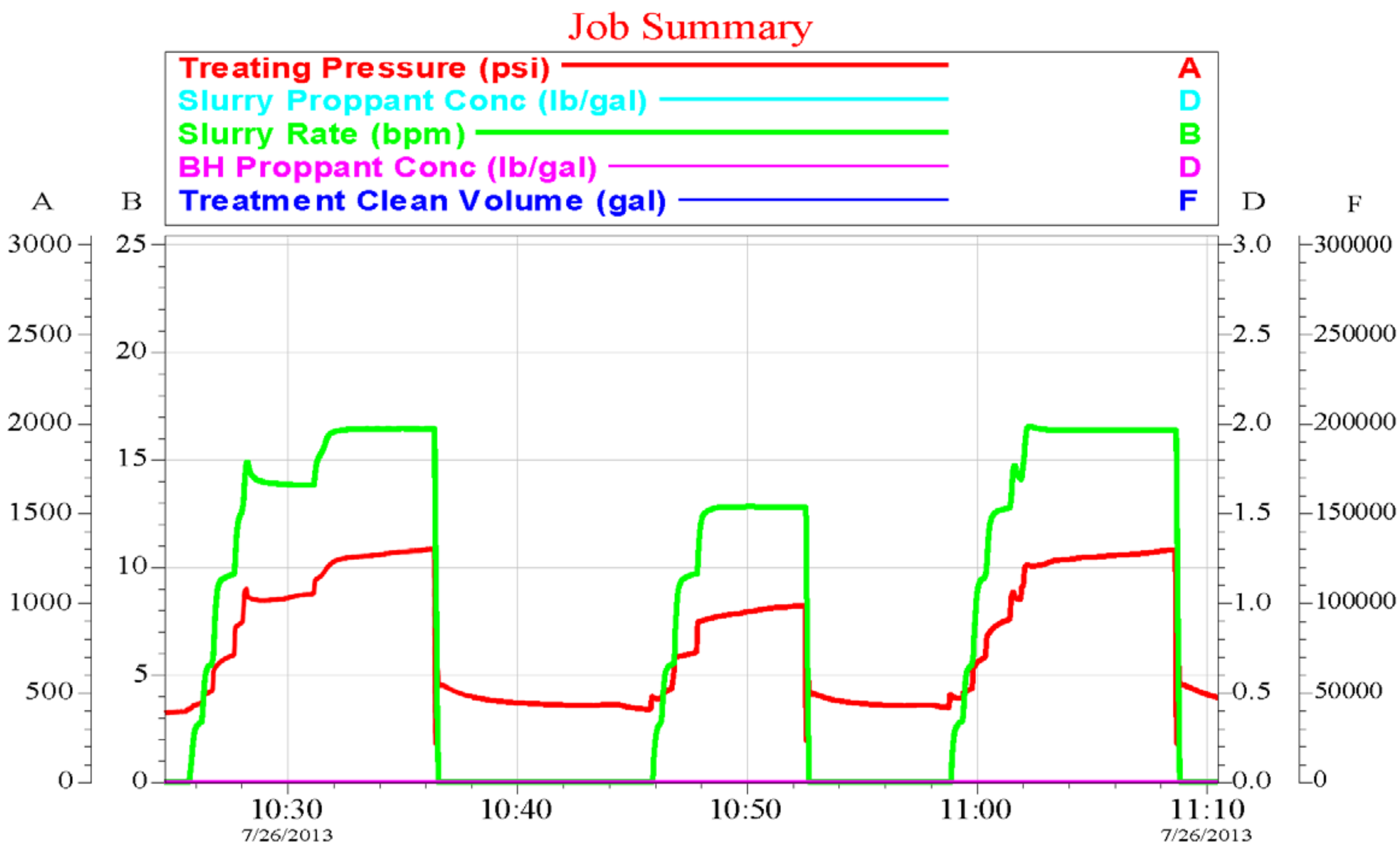
5.6 Clean Up (816 bbl)



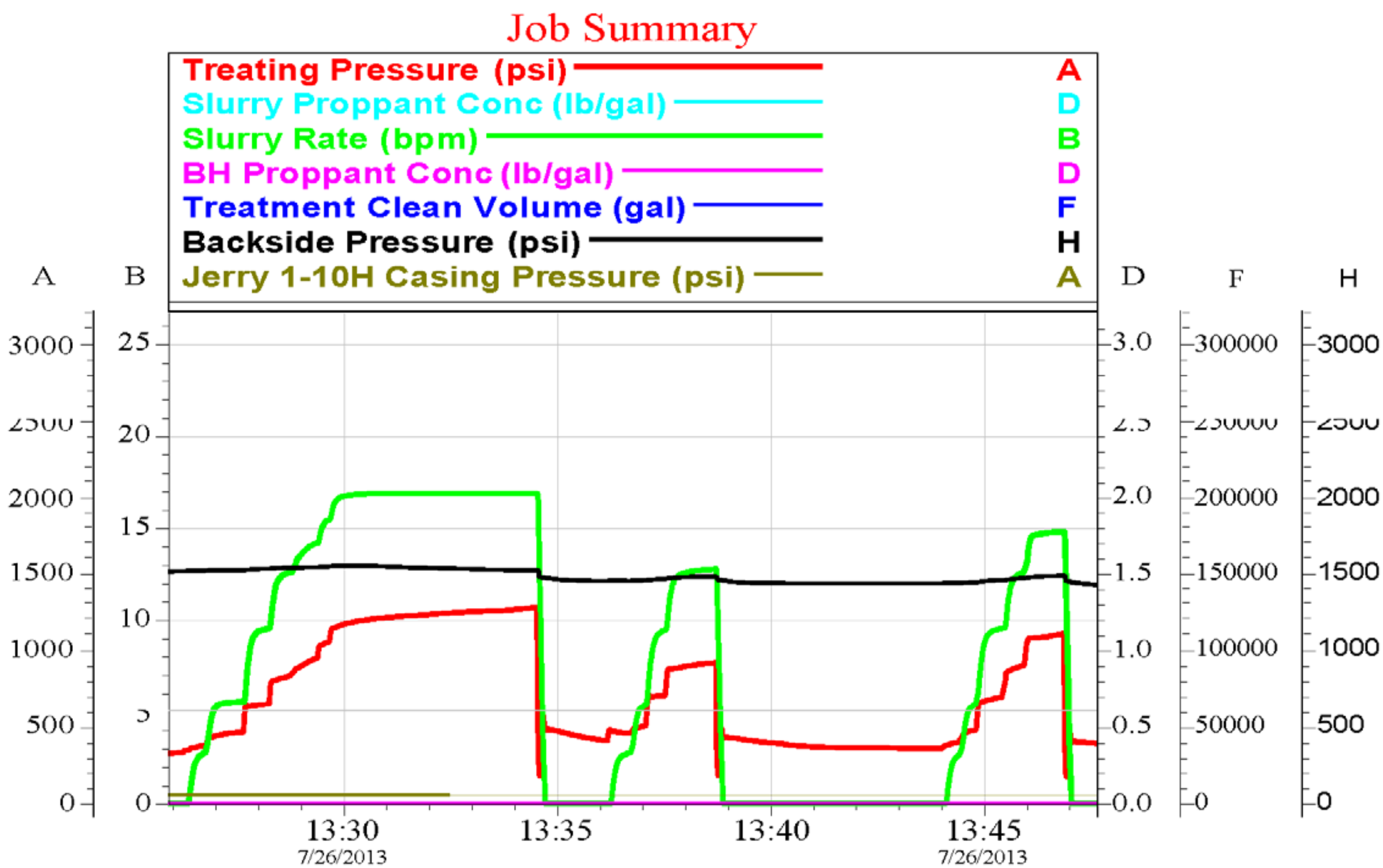
5.7 Pump Down After Stage 15b



5.8 Pump Down After Stage 15c



5.9 Pump Down After Stage 15d



5.10 Pump Down After Stage 15e