

Selected Topics in State and Local Regulation of Oil and Gas Exploration and Production*

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INTRODUCTION

With the interests in expanding domestic petroleum supplies in a time of “peak oil” and in avoiding the transfer of vast amounts of wealth to possibly unfriendly regimes, renewed attention is being given to the legal framework controlling oil and gas exploration and production (E&P). This report documents the efforts of more than 30 states that regulate the oil and gas industry, although many of the state regulatory schemes date from earlier waves of resource extraction, and have not kept pace with changed technologies, nor with a deepening concern for public health and the environment.

In regulating any extractive industry, regulators balance production needs against the interest in protecting public and ecosystem health. This report helps reveal the choices state regulators make in protecting the public from the array of detrimental environmental and public health side effects that accompany oil and gas drilling operations. The interests implicated include industry compliance costs, the costs of enforcement, public health, ecosystem health, wildlife protection, and risk mitigation, while the regulatory postures must choose between being flexible or specific; and geographically uniform or locally variable.

I. THE FEDERAL-STATE RELATIONSHIP

As a general matter, U.S. EPA and state governments collaborate on environmental protection. In many cases, states enforce federal standards, or standards that must be as rigorous as federal standards. The states now conduct between 80% and 90% of all environmental enforcement actions, while more than 75% of the major delegable environmental programs have been delegated to or assumed by the states.¹ The justification for this devolution of enforcement authority largely stems from the simple matter of proximity to the local environment. States typically can respond more quickly to local pollution problems, better understand environmental conditions, have more everyday interaction with the regulated community, and can be more innovative and flexible in their solutions.² Moreover, the federal government may facilitate state experimentation by giving states freedom to design their own plans, and then reviewing and financing approved plans.³

This report looks at a different aspect of this “collaborative federalism,” namely, state environmental enforcement in those instances when the major federal environmental statutes expressly provide the oil and gas industry with either qualified or complete exemptions from federal regulation. At the same time, most of those statutes expressly permit states to regulate these activities, preventing the possibility of federal pre-emption.⁴ The policy considerations for

¹ Joel Mintz, “Scrutinizing Environmental Enforcement: A Comment on a Recent Discussion at the AALs,” 17 J.Land Use & Env'tl. L. 127, 130 (2001).

² David R. Hodas, “Environmental Federalism: Enforcement of Environmental Law in a Triangular Federal System: Can Three Not Be a Crowd When Enforcement Authority Is Shared by the United States, the States, and Their Citizens?” 54 Md. L. Rev. 1552, 1571 (1995).

³ See *infra* note 132, and accompanying text.

⁴ See, e.g., Clean Air Act (CAA), section 7416 providing that states may “adopt or enforcement (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution.”

this de facto delegation to the states are similar, however, in that state and local government can be more responsive to oil and gas industry stakeholders, and tailor regulatory regimes more closely to account for regional population patterns (see, e.g., New Mexico's ambient hydrogen sulfide standards, below) and smaller pollution sources. The regulations may respond to local conditions, as well as customize an intensity of regulation commensurate with the level of industry activity (see, e.g., South Dakota with its 213 producing wells). The report notes that delegation does not end at the state level: for example, the state of California assigns local air districts responsibility for regulating emissions from stationary sources.

The Clean Air Act (CAA) exemption for air pollution emanating from oil and gas production illustrates the point: the CAA regulates large stationary sources through a permitting program, but leaves smaller "area sources" unregulated unless they are close to major metropolitan areas.⁵ Similarly, the CAA's aggregation rule, grouping sources under common control, does not apply to oil and gas emissions.⁶ The states, however, are left to make the determination whether the sources' cumulative environmental impact is a threat to the state's population.

Similarly, the Resource Conservation and Recovery Act (RCRA) provides that the byproducts of oil and gas exploration and production are not "hazardous" and therefore not covered by the statute. RCRA allows states to regulate exploration and production waste more restrictively, protecting the environment more rigorously than its standards. Of course, industry groups bring the same lobbying pressure against state regulatory efforts; the federal exemption may simply fractionate and localize the battle to set appropriate and sustainable levels of regulation of oil and gas pollution.

II. SURVEYING STATE STATUTES AND REGULATIONS

The following topics in an admittedly vast regulatory landscape were selected for the survey: hydrogen sulfide emissions, hazardous waste, and drillings and casings. These topics were chosen to present the wide variety of possible environmental effects of oil and gas exploration and production. Likewise, the topics selected demonstrate the range of issues and regulatory responses posed by the lifecycle of the oil and gas industry, from exploration, preliminary drilling, and disposal of drilling byproducts.

The write-ups, particularly in the appended charts, attempt to present the breadth of the state regulatory approaches, although we cannot vouchsafe the comprehensiveness of the results. The narratives themselves focus on states presenting noteworthy regulatory approaches by isolating the values that the various approaches advance. The primary research ended in June 2008, so regulations and legislation subsequent to that date will not appear in the summaries or charts.

⁵ CAA, section 7412(n)(4)(B).

⁶ CAA, section 7412(a)(1) defining a "major source" as any "stationary source or group of stationary sources located within a contiguous area and under common control" that emits threshold amounts of pollutants. The CAA's stationary source rule only applies to "major sources" per 7412(d)(1), hence non-aggregation of oil and gas emissions amounts to a substantial exemption, in view of the natural, geography-based clustering of exploration and production sites.

Some of the themes developed in this report include:

1. States respond to the federal regulatory gap with widely discrepant intensity and rigor

The drillings and casing section evidences a spectrum of regulation, from Texas's comprehensive regulations with multiple safeguards to New York's "disappointingly sparse" regulations. When permitting drilling sites and pits, some states are more stringent than others in how close these sites may be to sources of drinking water or natural waterways. Pennsylvania requires that drill pits be more than 100 feet from a body of water, whereas New Mexico only requires that such sites not be in a watercourse or wetland (although it is considering more stringent regulations).

Michigan and Wyoming are stricter than other states on what kinds of waste may not be placed in open pits. California is the only state that regulates the content and toxicity of produced water (an oil and gas production byproduct) before the disposal step. Even when deciding on how stringent regulations should be (*e.g.* must pits be lined?), regulators may choose to be even more specific and name precisely what kinds of materials at what thickness those liners must be.

2. States serve as proving grounds for best practices in regulation

Unlike instances where the U.S. EPA's regulations have taken on a nearly talismanic influence and choked off state innovation (see, *e.g.* supplemental environmental projects⁷), the states have fulfilled their promise for regulatory diversity in regulating the oil and gas industry. The hydrogen sulfide section points out three different ways of regulating hydrogen sulfide pollution. For example, Joseph points out distinctions between regulating oil and gas emissions based upon attainment of certain ambient pollution levels, and within that mode, states or regions employ many different possible ways of setting and monitoring those levels. Other jurisdictions place restrictions on where oil and gas activity can occur, for example, forbidding certain activities within a certain zone around residential areas. Or, pollution can be regulated through permits that monitor pollution from point sources. (*e.g.*, Michigan) However, choosing any one of these approaches may be less effective than choosing all of these approaches to offer maximal safeguards to human health. In the context of drilling and casing regulations, Texas distinguishes itself by not relying upon one mode of safeguard, but by requiring multiple safeguards at various stages of the drilling process.

The survey also uncovered instances where states have further delegated standard-setting and enforcement authorities, to regional authorities. For instance, the California Air Resources Board sets ambient air quality standards for hydrogen sulfide, but local air quality control districts have the primary enforcement responsibility. This flexible approach allows the regional authorities to achieve air quality standards through alternative mechanisms, in keeping with the chemical characteristics of the local petroleum.

⁷ See, *e.g.*, Public Law Research Institute, *Supplemental Environmental Projects* (2007), available at www.uchastings.edu/cs/gl/SEPs.html (last visited Dec. 1, 2008). This report notes that the states have oft adopted the EPA's guidelines for settling environmental enforcement actions with environmentally beneficial projects in place of the full measure of civil penalties, despite the fact that the states are not bound by the same Constitutional and statutory strictures as the federal government.

3. Given that pollution emanates from the many stages of production, and has the possibility of affecting both humans and nonhumans, regulators may be forced to prioritize regulatory efforts to minimize compliance costs

For example, hydrogen sulfide may be released at various stages of oil and gas production, and policymakers must decide which stages to regulate. To require safeguards on wellheads, pipelines, separators, and tanks would raise costs at every step of production, possibly driving producers out of business. In addition, practices to protect public health may complement practices that protect wildlife or natural systems, but sometimes extra (expensive) steps may be necessary to accomplish both goals.

4. Regulatory tradeoffs take unexpected turns in the states

While the general tradeoff between industry groups (looking to lower their costs of compliance) and the affected community (seeking to minimize the health and environmental effects of exploration and production) parallel battles seen at the federal and state levels, other, less obvious regulatory skirmishes play out. Particularly in the hydrogen sulfide context, the interests of densely populated urban areas are set against those of rural populations. In addition, given the press of residential development onto former ranchland, the regulatory priorities between urban and rural have become ever more difficult to account for.

Finally, in protecting human health, regulators must oftentimes settle on a single parameter: in regulating the placement of hazardous sites by creating buffer zones, are they to be disallowed near population centers, waterway, sensitive sites (such as schools or hospitals) or any building at all?

Katherine Joseph, Oil and Gas Exploration and Production and Hydrogen Sulfide: State Responses to Federal Failure to Regulate

INTRODUCTION

In the face of exemptions for the oil and gas industry in federal environmental legislation, many states have attempted to implement regulatory regimes to prevent environmental degradation and public health problems resulting from the industry's pollution. Potentially emitted during oil and gas exploration and production (E&P), hydrogen sulfide is a particularly dangerous air pollutant. Despite this fact, hydrogen sulfide released in the course of oil and gas production largely goes unregulated by the federal government's Clean Air Act (CAA). This paper sets out examples of state regulations that have effectively responded to the risks posed by hydrogen sulfide emissions in the course of E&P.

Section I provides a brief overview of the potential for, and risks associated with, hydrogen sulfide emissions from E&P activities. In addition, it explores the relationship between the decision on the federal level to shield the oil and gas industry from many Clean Air Act provisions, and the opportunity for state action in this area. Section II touches on the values informing state regulation of hydrogen sulfide—basic environmental and public health concerns, as well as pressure against overregulation.

Section III explores various ways in which states have chosen to regulate hydrogen sulfide emissions from E&P sources, comparing the practices of several states, and offering examples of unique state regulatory schemes. The main methods discussed are: ambient air standards, restrictions on E&P operations situated near public areas and residential zones, point-source emissions standards, and aggregation. Three models of ambient standards for hydrogen sulfide are profiled: California's uniform statewide ambient standard, New Mexico's region-specific standards, and Texas's variable standard. The sub-section dealing with restrictions on E&P operations in residential and public areas describes Michigan's restrictions on wells and their surface facilities and prohibition of flares associated with high hydrogen sulfide content wells in residentially zoned areas. The discussion of point-source standards addresses Michigan's toxics program, which requires individual sources exceeding the specified threshold to institute best available control technology for toxics (T-BACT).

Finally, the conclusion offers some guidance on the effectiveness of different regulatory strategies, explaining a few strengths and weaknesses of the differing types of regulation. For example, ambient standards alone may not be the most effective way to regulate the industry. While statewide ambient standards may affect the state's regulatory scheme overall, ambient standards such as those in California may not directly target E&P activities. Specific regulation through a point-source standard appears to be a more effective way to target the E&P industry; however it too has its weakness in that a standard geared exclusively toward individual sources may fail to recognize and address the accumulation of hydrogen sulfide from many sources. Similarly, restrictions on E&P operations situated near public and residential areas fail to account for emissions carried over by the wind.

Although each type of regulation has its flaws, the article concludes that a regulatory regime utilizing a combination of these methods would substantially decrease problems associated with hydrogen sulfide emissions. In addition to regulations specifically addressing hydrogen sulfide, it is important that a regulatory program determine source status⁸ by aggregating emissions from sources that are located in a contiguous area and under common control. The federal regulatory regime exempts E&P operations from the aggregation requirement, but aggregation is essential to effective regulation of hydrogen sulfide and other toxics.

I. HYDROGEN SULFIDE EMISSIONS AND THE FEDERAL CLEAN AIR ACT EXEMPTIONS FOR THE OIL AND GAS INDUSTRY

A. TECHNICAL BACKGROUND

Hydrogen sulfide emissions are a major problem for public health, and the environment. Because hydrogen sulfide exists naturally in oil and gas, it can be emitted during the extraction, storage, transportation, or processing stages of oil and gas production.⁹

There are many types of equipment that may give rise to hydrogen sulfide emissions during E&P activities.¹⁰ First, wellheads pump oil from the ground. Pump seals may leak, allowing hydrogen sulfide to escape into the atmosphere.¹¹ Once the oil is above ground, it is pumped into a treater used to direct oil and water emulsions into pipelines,¹² separators,¹³ and tanks.¹⁴ Hydrogen sulfide may be released by these pieces of equipment for a variety of reasons. Pipes and separation devices may leak hydrogen sulfide as a result of hydrogen sulfide's corrosive effect on metals or because of poor maintenance or poor materials.¹⁵ Treater may release hydrogen sulfide if pressures are too high or pressure changes exceed design specifications.¹⁶ Hydrogen sulfide may be released from storage tanks during the filling process.¹⁷

Hydrogen sulfide presents grave health risks. Even at relatively low levels, exposure to hydrogen sulfide can have detrimental effects on human health. The adverse health effects resulting from hydrogen sulfide range from mild irritation of the eyes, nose, and throat at lower

⁸ A "major source" is a source that meets a certain emissions threshold and is subject to more stringent regulations than a "minor source" or an "area source." See 42 U.S.C. § 7412(A) (2008).

⁹ Lana Skrtic, *Hydrogen Sulfide, Oil and Gas, and People's Health* (May 2006), at 7, available at http://www.earthworksaction.org/pubs/hydrogensulfide_oilgas_health.pdf (last visited Dec. 1, 2008).

¹⁰ *Id.* at 8.

¹¹ Skrtic, *supra* note 9, at 8 (citing Environmental Protection Agency, *Report on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas*, (1993) P.II-6).

¹² Skrtic, *supra*, note 9, at 8; Schlumberger, *Schlumberger Oilfield Glossary*, available at <http://www.glossary.oilfield.slb.com/> (search "treater") (last visited May 7, 2008).

¹³ Schlumberger Oilfield Glossary, *supra* note 12 (search "separator").

¹⁴ Skrtic, *supra* note 9, at 8.

¹⁵ *Id.*

¹⁶ *Id.*

¹⁷ *Id.*

levels of exposure to loss of consciousness and death at increased levels of exposure.¹⁸ In small concentrations, hydrogen sulfide gives off the odor of rotten eggs. In high concentrations, however, it impairs a person's ability to smell and becomes even more dangerous because there is no way for a person to detect its presence.¹⁹ As hydrogen sulfide is heavier than air, it may concentrate in low lying areas, after accidental release. Residents who live near industries that emit hydrogen sulfide tend to have an increased risk of eye irritation, cough, headache, nasal blockage and impaired neurological function when compared to those who are not chronically exposed to hydrogen sulfide.²⁰ Chronic exposure in residential areas can result from direct proximity to E&P operations and/or from location downwind of an emissions source.²¹ Harmful exposure can also result from accidental releases. One study documented a series of explosions in California that adversely affected the health of 7,000 people living in four adjacent cities.²²

Regardless of the manner of hydrogen sulfide exposure it can only result in an undesirable effect on human health. There are several methods of reducing hydrogen sulfide emissions associated with E&P operations and thus decreasing the likelihood of exposure. One method is scrubbing. In this process, the gas stream is directed through a scrubber, which washes out or absorbs the hydrogen sulfide by mixing the gas with a suitable liquid.²³ Flaring is another method used to control hydrogen sulfide emissions. Flaring is a process by which gas is released and combusted.²⁴ When hydrogen sulfide is combusted it becomes sulfur dioxide, which can then be scrubbed to remove some of its harmful properties.²⁵ Preventing the corrosion of E&P equipment may also control hydrogen sulfide emissions.

B. FEDERAL LAW REGARDING OIL AND GAS INDUSTRY EMISSIONS

The federal Clean Air Act (CAA) authorizes the Environmental Protection Agency (EPA) to establish national emissions standards for hazardous air pollutants (NESHAPs), which cover 188 hazardous air pollutants (HAPs).²⁶ The CAA defines sources of HAPs in two ways: major sources and area sources. A major source is a source or a group of sources "located within a contiguous area and under common control" that emits 10 tons per year or more of a particular HAP or 25 tons per year of a mixture of toxics.²⁷ An area source emits less than 10 tons per year of a particular toxic or less than 25 tons per year of a mixture of toxics.²⁸ The standards the EPA sets for a particular source category require the highest degree of achievable emissions reduction

¹⁸ Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Hydrogen Sulfide*, 10-11 (2006), available at <http://www.atsdr.cdc.gov/toxprofiles/tp114.pdf>.

¹⁹ *Id.* at 2.

²⁰ New York Dep't of Health, "Hydrogen Sulfide Chemical Information Sheet," available at http://www.health.state.ny.us/environmental/chemicals/hydrogen_sulfide (last visited Dec. 3, 2008).

²¹ Skrtic, *supra* note 9, at 21, 40.

²² *Id.* at 17.

²³ *Schlumberger Oilfield Glossary*, *supra* note 12 (search "scrub") (last visited May 7, 2008).

²⁴ Earthworks, "Sources of Oil and Gas Air Pollution," available at <http://www.earthworksaction.org/airpollutionsources.cfm> (last visited May 7, 2008).

²⁵ Skrtic, *supra* note 9, at 8.

²⁶ 42 U.S.C. § 7412 (2008). In addition to regulating NESHAPs, the CAA authorizes the EPA to set National Ambient Air Quality Standards which regulate emissions of pollutants from stationary and mobile sources. 42 U.S.C. § 7409 (2008).

²⁷ 42 U.S.C. § 7412(A)(1) (2008).

²⁸ 42 U.S.C. § 7412(A)(2) (2008).

by each source category.²⁹ Oil and gas E&P operations emit many of the HAPs on the EPA's list, but hydrogen sulfide is not included on the list of 188 hazardous pollutants. Thus, the CAA does not require the oil and gas industry to undertake any of the prophylactic measures for hydrogen sulfide discussed above, such as scrubbing or flaring, in its E&P activities.

The CAA provides for the regulation of large stationary sources through the Title V permitting program.³⁰ A Title V permit is required for all major sources and for some area sources subject to NESHAP standards.³¹ States are largely responsible for the implementation of the Title V program,³² which mandates the creation of a monitoring plan and places limitations on amounts and types of emissions.³³ While all major E&P sources are required to obtain Title V permits, area sources are generally not required to do so.³⁴

C. EXEMPTIONS FOR THE OIL AND GAS INDUSTRY

1. *The CAA's Failure to Aggregate Emissions of Hazardous Air Pollutants*

The CAA provides exemptions for the oil and gas industry that greatly diminish the effectiveness of the federal regime's ability to reduce emissions of hazardous air pollutants.³⁵ Typically, emissions from different facilities that are contiguous and under common control are aggregated together for the purposes of determining major source status.³⁶ However, the oil and gas industry is exempt from this aggregation requirement. Emissions from oil and gas E&P equipment and facilities may not be measured in aggregate for the purposes of federal regulation even if they are contiguous and under common control.³⁷ The CAA also exempts oil and gas E&P equipment and facilities from most regulation as area sources.³⁸ Oil and gas E&P facilities may not be classified as area sources unless they are "located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million," and the EPA in its discretion "determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health."³⁹ Consequently, individual major sources are automatically subject to regulation, while urban area sources are

²⁹ 42 U.S.C. § 7412(d) (2008). "Different criteria for maximum achievable control technology (MACT) apply for new and existing sources." U.S. EPA, "CAA Section 112(d)," *available at* www.epa.gov/ttn/atw/112dpg.html (last visited May 8, 2008). At the Administrator's discretion, less stringent standards (generally available control technology, or GACT) are allowed for area sources. *Id.* "Since 1997, EPA has brought enforcement actions for [NESHAP] violations in over 500 administrative penalty cases and nearly 100 judicial enforcement cases, some involving penalties and environmental projects over \$1 million each." EPA.gov, "Clean Air Act National Enforcement Program," *available at* <http://www.epa.gov/compliance/civil/caa/caaenfprog.html> (last visited May 8, 2008).

³⁰ U.S. EPA, "Operating Permits," *available at* <http://www.epa.gov/air/oaqps/permits> (last visited May 8, 2008); 42 U.S.C. § 7661 (2008).

³¹ 42 U.S.C. § 7661a(a) (2008).

³² 42 U.S.C. § 7661a(d) (2008).

³³ 42 U.S.C. § 7661a (2008); 40 C.F.R. § 70.1 (2008).

³⁴ 40 C.F.R. § 63.760(h) (2008).

³⁵ As discussed below, hydrogen sulfide is not on the list of 188 HAPs; therefore, the aggregation exemption does not currently affect hydrogen sulfide emissions at all.

³⁶ 42 U.S.C. § 7412(a)(1) (2008).

³⁷ 42 U.S.C. § 7412(n)(4)(A) (2008).

³⁸ 42 U.S.C. § 7412(n)(4)(B) (2008).

³⁹ *Id.*

subject to regulation at the EPA's discretion. The federal regime does not regulate sources located in non-urban areas that do not qualify as major sources.

2. Aggregation and Its Relationship to Hydrogen Sulfide Regulation

As noted above, hydrogen sulfide is not on the list of hazardous air pollutants and so is not subject to a NESHAP. The federal government's failure to regulate the toxic pollutant is particularly advantageous for the oil and gas industry, as the industry is a sizeable source of hydrogen sulfide emissions.⁴⁰ In fact, hydrogen sulfide was kept off of the HAP list as a result of pressure from the oil and gas and paper pulp industries.⁴¹ Several environmental groups, including the Earthworks Oil and Gas Accountability Project,⁴² and the Natural Resources Defense Council⁴³ recommend that the federal government revisit its decision not to regulate hydrogen sulfide as a HAP. However, even if the federal government decided to regulate hydrogen sulfide emissions, the effect of that regulation would be diminished by the aggregation exemption. If the regulation of hydrogen sulfide is to be effectively addressed at the federal level hydrogen sulfide needs to be regulated *and* the aggregation exemption for the industry would have to be rescinded.⁴⁴

Notwithstanding the federal regulatory regime, states have a lot of room to create their own regulatory regimes. Under the CAA, states have the power to implement regulatory regimes that provide more stringent requirements than those set forth under the federal regulations.⁴⁵ While states do not have the authority "to adopt or enforce any emissions standard which is less stringent" than that articulated by the CAA or its implementing regulations, the CAA "shall [not] preclude or deny the right of any State or political subdivision thereof to adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution."⁴⁶ Many states have opted to regulate oil and gas E&P operations, including hydrogen sulfide emissions, more strictly than the federal government.

II. VALUES WHICH SHAPE THE STATES' REGULATORY SCHEMES

As revealed in discussions with personnel in several states, basic environmental and public health values influence states' decisions to aggregate E&P emissions and regulate hydrogen sulfide in the oil and gas industry. The state agencies that adopt stricter regulations for the industry typically cite a general interest in public welfare and the protection of people's health as the reasons for regulation. As an outgrowth of the general concern for public welfare,

⁴⁰ Earthworks, "Hydrogen Sulfide," available at <http://www.earthworksaction.org/hydrogensulfide.cfm> (last visited May 8, 2008).

⁴¹ Jim Morris, "Lost Opportunity: EPA Had Its Chance to Regulate Hydrogen Sulfide," *Houston Chronicle*, November 8, 1997, <http://www.chron.com/content/chronicle/nation/h2s/lostop.html> (last visited May 8, 2008) (cited in Amy Mall, *Drilling Down: Protecting Western Communities from the Health and Environmental Effects of Oil and Gas Production* at 13, available at <http://www.nrdc.org/land/use/down/down.pdf> (last visited May 8, 2008)).

⁴² Renee Lewis Kosnik, *The Oil and Gas Industry's Exclusions and Exemptions to Major Environmental Statutes*, at 3, available at <http://www.earthworksaction.org/pubs/PetroleumExemptions1c.pdf> (last visited May 8, 2008).

⁴³ Mall, *Drilling Down*, *supra*, note 41, at 32.

⁴⁴ *Id.*

⁴⁵ 42 U.S.C. § 7416 (2008).

⁴⁶ *Id.*

some states tailor their regulatory regimes to be more stringent around densely populated areas. Texas and New Mexico, for example, have implemented stricter ambient hydrogen sulfide standards near populated areas. These differing standards not only take into account public welfare, but also oil and gas industry concerns of overregulation. However, this trade-off can be problematic. In New Mexico, the more stringent ambient standard does not go into effect until a municipality's population reaches 20,000, leaving rural communities at risk for exposure to air toxics.⁴⁷

III. STATE REGULATION OF AIR CONTAMINANTS PRODUCED BY OIL AND GAS E&P

A. AMBIENT STANDARDS FOR HYDROGEN SULFIDE

An ambient air standard is the highest concentration of a particular air pollutant, measured at an outdoor location, during a specified unit of time, that is not considered hazardous to humans. Implementation of ambient air standards reflect a state's concern for the overall health and wellbeing of its residents. In general, state strategies for implementing ambient air standards are fairly similar to those employed by federal government, even when the states regulate pollutants not covered by the federal regime. Under the federal regime, areas are considered in "attainment" of an ambient standard if the ambient concentration of a regulated pollutant does not exceed that standard.⁴⁸ Areas that fail to meet the ambient standards are labeled "nonattainment."⁴⁹ The CAA requires that nonattainment areas be more strictly regulated than areas in attainment. Once an area is designated as "nonattainment," the state in which the nonattainment area is located must implement a cleanup plan, providing for expeditious attainment of the standard.⁵⁰ Plans should include requirements such as a permitting process for new and modified stationary sources and the implementation of reasonably available control method to reduce harmful emissions, among other requirements.⁵¹

At least fourteen oil-producing states do have ambient standards.⁵² The state standards vary widely in the relative strictness and uniformity,⁵³ but their implementation generally adheres to the basic attainment/nonattainment model set forth in the CAA. Under the California regime, for example, nonattainment districts must execute plans that require stationary sources to use technology that will better control their emissions and to closely monitor their emissions.⁵⁴

1. California's Ambient Standard

⁴⁷ The New Mexico Code provides: "For within five miles of the corporate limits of municipalities having a population of greater than twenty thousand and within the Pecos-Permian Basin Intrastate Air Quality Control Region (1/2 hour average)"... it does not state a land area requirement but just in relation to a municipality. N.M. CODE R. § 20.2.3.

⁴⁸ 42 U.S.C. § 7407(d)(1)(A)(ii) (2008).

⁴⁹ 42 U.S.C. § 7407(d)(1)(A)(i) (2008).

⁵⁰ 42 U.S.C. § 7502(c) (2008).

⁵¹ 42 U.S.C. § 7502 (2008).

⁵² Arizona, California, Kentucky, Louisiana, Missouri, Montana, Nevada, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming.

⁵³ In New Mexico, for example, the ambient standard varies throughout the state and is less strict in areas with high concentrations of oil and gas E&P operations and low population. In contrast, California's ambient standard uniformly covers the entire state.

⁵⁴ CAL. HEALTH & SAFETY CODE § 40918 (2008).

The California Health and Safety Code authorizes the California Air Resources Board (CARB) to create ambient air quality standards.⁵⁵ In 1969, CARB adopted a statewide ambient hydrogen sulfide standard of 0.03 ppm averaged over 1 hour,⁵⁶ which it has since retained.⁵⁷ While CARB creates the standards, local air quality control districts have the primary responsibility for enforcing the standards.⁵⁸ Local air control districts also have the primary responsibility for regulating stationary sources.⁵⁹

Although they are charged with enforcing the state ambient standard, two of the air districts with the highest concentrations of oil and gas E&P activity—the South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Air Pollution Control District⁶⁰ (SJV)—do not have specific rules regulating hydrogen sulfide emissions from oil and gas E&P facilities. In general, the ambient standard affects the way in which the districts author their regulations on the whole, but does not require that they take specific notice of hydrogen sulfide.⁶¹ Regulation of hydrogen sulfide emissions takes place in an indirect way.

SJV, for example, regulates the emissions of sulfur oxides, having the collateral effect of reducing hydrogen sulfide emissions.⁶² Personnel at SJV explained that gas containing sulfur oxides is flared and then sent through a scrubber; the process of flaring the emissions has the function of removing some of the hydrogen sulfide.⁶³ Through this process, SJV is able to remain in attainment of the state hydrogen sulfide standard.⁶⁴

Similarly, the SCAQMD's standards for flaring and equipment such as valves and flanges keep the ambient levels low enough to keep the district in attainment.⁶⁵ Mike Mills explained that the oil and gas coming out of his district does not have a very high hydrogen sulfide content to begin with.⁶⁶ Consequently, the ambient standard does not have a direct effect on oil and gas E&P operations in the SCAQMD district.⁶⁷

⁵⁵ CAL. HEALTH & SAFETY CODE §§ 39600, 39601(a), 39606 (2008).

⁵⁶ Most states with ambient standards measure hydrogen sulfide concentrations in parts per million (ppm) or parts per billion (ppb) as a time-weighted average. A time-weighted average indicates the average concentration of hydrogen sulfide in the ambient air for a specified period of time. For example, a state with an ambient standard of 0.08 ppm/ 1 hour will average the concentration of hydrogen sulfide over one hour; if the average exceeds 0.08 ppm, the ambient standard has been violated. For the sake of uniformity, I have converted all values to ppm where possible, although the regulations may list them as ppb or ug/m³ (micrograms per cubic meter of air).

⁵⁷ California Air Resources Bd., "Hydrogen Sulfide," *available at* <http://www.arb.ca.gov/research/aaqs/caaqs/h2s/h2s.htm> (last visited May 21, 2008).

⁵⁸ CAL. HEALTH & SAFETY CODE §40000 (2008).

⁵⁹ *Id.*

⁶⁰ Telephone Interview with Mike Mills, Senior Air Quality Manager, South Coast Air Quality Management District (March 24, 2008).

⁶¹ Telephone Interview with Leonard Scandura, Supervising Air Quality Engineer, San Joaquin Valley Air Pollution Control District (May 21, 2008).

⁶² San Joaquin Valley Air Pollution Control District Rule 2201, *available at* <http://www.valleyair.org/rules/currnrules/r2201.pdf> (last visited May 24, 2008).

⁶³ Telephone Interview with Leonard Scandura, *supra* note 61.

⁶⁴ *Id.*

⁶⁵ Telephone Interview with Mike Mills, *supra* note 60.

⁶⁶ *Id.*

⁶⁷ *Id.*

2. Texas's Ambient Standard

In Texas, most of the regulation of emissions from oil and gas operations falls under the authority of the Texas Commission on Environmental Quality (TCEQ). TCEQ is responsible for promulgating regulations concerning ambient hydrogen sulfide standards.⁶⁸ Texas's ambient standard, in contrast to California's, is not uniform throughout the state, but varies in response to the potential impact of emissions on populated areas. For emissions that have the potential to travel downwind to residential, business, or commercial areas, the ambient standard is 0.08 ppm averaged over 30 minutes.⁶⁹ For emissions that have the potential to travel downwind to areas that are not typically occupied by people, the ambient standard is 0.12 ppm averaged over 30 minutes.⁷⁰ This standard reflects the interests of industry as well as a concern for public safety.

3. New Mexico's Ambient Standard

In New Mexico, the state's Air Quality Bureau (AQB) is responsible for ensuring compliance with air quality standards.⁷¹ Similar to Texas's, New Mexico's ambient standard varies based on population density, but differs in that it also factors in the concentration of E&P operations in a particular area, an indirect counter to the federal anti-aggregation policy.⁷² New Mexico has a general statewide ambient standard of 0.010 ppm averaged over 1-hour, which is "not to be exceeded more than once per year."⁷³ However, there is an exception to that standard. The Pecos-Permian Basin Intrastate Air Quality Control Region (PPB) has a more lenient standard of 0.100 ppm averaged over ½-hour.⁷⁴ PPB is located in the southeast corner of the state and has the highest concentration of E&P operations in the state.⁷⁵ For municipalities in PPB with a population of more than 20,000 people, a standard of 0.030 ppm averaged over ½-hour is in effect for everything within a five-mile radius of those municipalities.⁷⁶ This standard is mainly enforced through flaring requirements, and enforcement actions are infrequent.⁷⁷ The less stringent standards in PPB are a result of the New Mexico Oil and Gas Association's

⁶⁸ TCEQ is also responsible for other areas of regulation concerning the oil and gas industry, including preconstruction authorization, installation and modification of oil and gas facilities, construction authorization for permitting, and the nuisance rule. Texas Commission on Environmental Quality, *Technical Guidance Package for Chemical Sources: Hydrogen Sulfide*, (2001) available at <http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/rg339.pdf> (last visited May 10, 2007).

⁶⁹ 30 TEX. ADMIN. CODE § 112.31 (2008).

⁷⁰ 30 TEX. ADMIN. CODE § 112.32 (2008).

⁷¹ New Mexico Environment Dep't, "Air Quality Bureau," available at <http://www.nmenv.state.nm.us/aqb> (last visited May 25, 2008).

⁷² Telephone Interview with Andy Berger, New Mexico Environment Dep't, Air Quality Bureau (April 9, 2008).

⁷³ NEW MEXICO ADMIN. CODE § 20.2.3.110 (2008), available at <http://www.nmcpr.state.nm.us/NMAC/parts/title20/20.002.0003.htm> (last visited May 21, 2008).

⁷⁴ *Id.*

⁷⁵ Telephone Interview with Andy Berger, *supra* note 72.

⁷⁶ NEW MEXICO ADMIN. CODE § 20.2.3.110 (2008), available at <http://www.nmcpr.state.nm.us/NMAC/parts/title20/20.002.0003.htm> (last visited May 21, 2008).

⁷⁷ Telephone Interview with Andy Berger, *supra* note 72.

contentions that stricter standards would be economically unfeasible,⁷⁸ a contention widely used in the battle at the national level over the listing of hydrogen sulfide as a hazardous air pollutant.

B. RESTRICTIONS ON E&P OPERATIONS SITUATED NEAR PUBLIC AREAS AND AREAS ZONED FOR RESIDENTIAL USE

Michigan has promulgated regulations that restrict E&P operations situated within or near areas open to the public. The regulations provide a framework that seems to address concerns of the potential for acute exposure to hydrogen sulfide and mitigates the impact of E&P operations on local communities. Community members and public health advocates, however, may disagree with the meaningfulness of the restrictions. The Department of Environmental Quality (DEQ) Office of Geological Survey, Geological and Land Management Division sets and enforces the regulations.⁷⁹

In Michigan, E&P wells and surface facilities constructed after 1987 may not be located within 300 and 600 feet, respectively, of “existing structures for public or private occupancy, existing areas maintained for public recreation, or the edge of the traveled portion of an existing interstate, United States, or state highway.”⁸⁰ Additionally, a facility that was substantially reconstructed after 1987 may be required to relocate if it poses a risk of acute exposure.⁸¹ The restriction applies to all areas regardless of how they are zoned, thus ensuring some level of protection for those who could potentially be affected by hydrogen sulfide emissions from wells. The regulation is intended to target well bores and their associated surface facilities.⁸² Surface facilities refer to much of the equipment used for producing, processing, or treating oil or gas, including pumping equipment, separators, and storage tanks.⁸³

Another mechanism Michigan utilizes to control hydrogen sulfide emissions is the virtual prohibition of locating flare stacks and their surface facilities near residential areas.⁸⁴ Flares and surface facilities may not be located in areas zoned residential before 1993, if the well associated with the facilities contains 300 ppm or more hydrogen sulfide and has reached drilling completion.⁸⁵ There are some exceptions to this rule - surface facilities or flare stacks may be located in residential areas if local governmental bodies consent to it, or if drilling completion

⁷⁸ “New Mexico Ambient Air Quality Standard for Hydrogen Sulfide (H₂S): Brief Historical Summary of Standards and Rationale,” (April 10, 2008) (on file with author).

⁷⁹ Michigan Dep’t of Environmental Quality, “Hydrogen Sulfide Q&A,” *available at* http://www.michigan.gov/deq/0,1607,7-135-3311_4111_4231-9162--,00.html (last visited May 10, 2008). A fuller sense of community frustration with the 1998 revisions to Michigan’s hydrogen sulfide rules (particularly the post hoc effect of the rules) is provided in a 2003 report authored by Dana Schindler, *SURVEY of ACCIDENTAL and INTENTIONAL HYDROGEN SULFIDE (H₂S) RELEASES CAUSING EVACUATIONS and/or INJURY in Manistee and Mason Counties from 1980 to 2002*, *available at* <http://www.mecprotects.org/oilaccidents2.pdf> (last visited April 3, 2009).

⁸⁰ MICH. ADMIN. CODE R. 324.1106 (2008).

⁸¹ *Id.*

⁸² Telephone interview with Ray Vugrinovich, Senior Geologist, Mich. Dep’t of Environmental Quality, Office of Geological Survey (May 22, 2008).

⁸³ MICH. ADMIN. CODE R. 324.103(p) (2008).

⁸⁴ MICH. ADMIN. CODE R. 324.506 (2008).

⁸⁵ *Id.*

took place between 1987 and 1993.⁸⁶ Despite the exceptions, this regulation provides an example of how the state of Michigan has moved towards more effective restriction on E&P operations close to residential areas.

C. POINT-SOURCE EMISSIONS STANDARDS

1. Michigan's Air Toxics Program for Hydrogen Sulfide

While Michigan does not have a statewide ambient standard for hydrogen sulfide, a relatively strict screening standard for hydrogen sulfide and other toxics has been established. Michigan's Department of Environmental Quality's Air Quality Division (AQD) is responsible for enforcing air toxics rules.⁸⁷ Under the rules, a toxic air contaminant (TAC) is an air contaminant that is or may be potentially harmful to public health and for which there is no national ambient air quality standard.⁸⁸ Hydrogen sulfide is covered under the rule.⁸⁹

Indicating its purpose, Michigan's air toxics rule is entitled: "Health-based screening level requirement for new or modified sources of air toxics."⁹⁰ The rule provides that a new or modified emissions unit which requires a permit application prior to installation cannot emit a TAC that exceeds the maximum allowable emission rate [MAER].⁹¹ The MAER is set through a dispersion modeling technique by the permit engineers who draft the initial permit.⁹² Because much of the equipment associated with oil and gas E&P requires a permit, the rule has an impact on E&P operations. For hydrogen sulfide, the initial threshold screening level is 2 ug/m³ averaged over 24 hours.⁹³ According to Bryce Feighner, the rule has a similar effect as a statewide ambient standard in that the strict threshold results in the concentration of hydrogen sulfide at any given time remaining near the threshold level.⁹⁴ Once a source has been found to be emitting a TAC above the threshold level, that source must implement the best available

⁸⁶ MICH. ADMIN. CODE R. 324.506 (2008). Drilling completion is defined as "the time when a well has reached its permitted depth," or the administrative authority "has determined that drilling has ceased." MICH. ADMIN. CODE R. 324.102(l) (2008). The provisions regarding drilling completion are designed to prevent retroactive application of the law. Telephone interview with Ray Vugrinovich, *supra* note 82. Drilling completion is not a predicate of the law; i.e. if an oil company wanted to begin drilling in a residential area tomorrow, it would be subject to the prohibition on flares even though it had not yet reached drilling completion. *Id.*

⁸⁷ Michigan Dep't of Environmental Quality, "Hydrogen Sulfide Q&A," *supra* note 79. AQD is also responsible for issuing permits on "some of the equipment associated with wells and processing facilities such as storage tanks, flares and other fuel burning equipment, depending on the amount of emissions expected to be discharged."

⁸⁸ Michigan Dep't of Environmental Quality, "Overview of Michigan's Air Toxics Rules," *available at* http://www.michigan.gov/deq/0,1607,7-135-3310_4105-11749--,00.html (last visited May 16, 2008).

⁸⁹ Michigan Dep't of Environmental Quality, *Air Quality Division List of Screening Levels* (2008), *available at* http://www.michigan.gov/documents/deq/deq-aqd-toxics-ITSLALPH_244167_7.pdf (last visited Dec. 22, 2008).

⁹⁰ MICH. ADMIN. CODE R. 336.1225 (2008).

⁹¹ *Id.*; see also Michigan Dep't of Environmental Quality, Air Quality Div., *Air Contaminants – Demonstrating Compliance With Rule 225* (2004), *available at* http://www.michigan.gov/documents/TACS_Demonstrating_Compliance_with_Rule_225_117508_7.pdf (last visited May 16, 2008).

⁹² Telephone Interview with Michael Depa, Toxicologist, Mich. Dep't of Environmental Quality, Air Quality Division (May 19, 2008).

⁹³ *Air Quality Division List of Screening Levels* (2008), *supra* note 89, at 33.

⁹⁴ Email from Bryce Feighner, Chemical Process Unit Supervisor, Air Quality Division, Mich. Dep't of Environmental Quality, Air Quality Division (April 1, 2008) (on file with author).

control technology for toxics (T-BACT).⁹⁵

Mike Depa, a toxicologist with the DEQ, suggested that placing a strict threshold on emissions levels is preferable to imposing an ambient standard because the emissions threshold is more exact and easier to keep track of.⁹⁶ According to Depa, ambient monitoring is subject to inaccuracies based on differences in meteorological conditions.⁹⁷ The dispersion modeling used for the strict threshold model is highly accurate, and permit engineers can calculate which emissions rate would meet the screening level with great precision.⁹⁸

D. AGGREGATION REQUIREMENTS FOR HAZARDOUS AIRBORNE POLLUTANTS OTHER THAN HYDROGEN SULFIDE

Although the federal CAA does not preempt states from exercising more stringent regulation of E&P than the federal statute requires, most states do not have specific regulations that require the aggregation of emissions from oil and gas facilities. New Mexico, for example, defines major sources exactly the way they are defined in the federal CAA. The language used in the New Mexico regulations is identical to that used in the federal regulations and by many other states that have chosen not to aggregate E&P emissions.⁹⁹ Aggregation rules can act to prevent harmful concentrations of hydrogen sulfide emanating from multiple sources. However, as noted above, the aggregation of E&P facilities for the determination of major source status does not have a direct effect on hydrogen sulfide regulations. Should the federal government decide to revisit the issue of aggregation, it is also important that hydrogen sulfide be included among the HAPs affected by federal regulation.

While most states have chosen not to aggregate oil and gas emissions of HAPs, a few nonconforming states have taken on the responsibility of doing so through different approaches. California, for example, leaves the decision of whether and how to aggregate E&P emissions completely up to local air districts, while Michigan leaves the decision of whether to aggregate up to local air districts, which use aggregation guidelines created by the EPA.

1. California Air Districts

⁹⁵ “Overview of Michigan’s Air Toxics Rules,” *supra* note 88; MICH. ADMIN. CODE R. 336.1227 (2008).

⁹⁶ Telephone Interview with Michael Depa, *supra* note 92.

⁹⁷ *Id.*

⁹⁸ *Id.*

⁹⁹ The regulations provide: “For pollutants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, 10 tons or more per year of any hazardous air pollutant which has been listed pursuant to Section 112 (b) of the federal act, 25 or more tons per year of any combination of such hazardous air pollutants (including any major source of fugitive emissions of any such pollutant, as determined by rule by the administrator), or such lesser quantity as the administrator may establish by rule. *Notwithstanding the preceding sentence, hazardous emissions from any oil or gas exploration or production well (with its associated equipment) and hazardous emissions from any pipeline compressor or pump station shall not be aggregated with hazardous emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources.*” (emphasis added) N.M. Code R. § 20.2.70.7 (2008).

California delegates the regulation of stationary source emissions to local air districts.¹⁰⁰ Each district has a separate set of rules to deal with oil and gas E&P. The San Joaquin Valley Air Pollution Control District (SJV) has perhaps the most inventive scheme;¹⁰¹ SJV's aggregation requirement is embedded in its definition of "stationary source."¹⁰² SJV aggregates E&P operations based on common ownership, the type of oil being produced,¹⁰³ and location in a particular oil field.¹⁰⁴ The district has three oil fields: Western Kern County Oil Fields, Central Kern County Oil Fields, and Fresno County Oil Fields.¹⁰⁵ A source is considered to be a single source if it is located within one of the three oil fields, is under common ownership, and is engaged in one type of production.¹⁰⁶ For example, all of an oil company's heavy oil E&P activities located in the Central Kern County Oil fields will be aggregated together to make one source, while the same oil company's light oil activities in the same oil fields will be a separate source, and its light oil activities on a different oil field will be yet another source.

2. Michigan's Approach to Aggregation and the EPA Memo

Michigan gives its air districts discretion as to whether or not they will aggregate emissions for the purposes of determining major source status.¹⁰⁷ However, Michigan believes that this discretion is limited by an EPA memo providing guidance to permitting authorities when making major stationary source determinations for the oil and gas industry.¹⁰⁸ The EPA memo provides that operational dependence and proximity impact whether two properties are considered "contiguous or adjacent and that it is consistent with federal law to aggregate properties that are contiguous and adjacent."¹⁰⁹

Under the memo's analytical structure, a reviewing authority should first identify an individual surface site.¹¹⁰

The term 'surface site' generally refers to a single area of

¹⁰⁰ CAL. HEALTH & SAFETY CODE § 40000 (2008).

¹⁰¹ San Joaquin Valley Air Pollution Control District Rule 2201(3.37) (2008), *available at* <http://www.valleyair.org/rules/currnrules/r2201.pdf> (last visited May 25, 2008).

¹⁰² *Id.*

¹⁰³ San Joaquin Valley Air Pollution Control District Rule 2201 places all possible types of production into three categories: heavy oil, light oil, and gas. Heavy oil has an American Petroleum Institute gravity of 20 degrees or less. San Joaquin Valley Air Pollution Control District Rule 2201(3.20) (2008). While the rule does not define light oil, light oil presumably has an American Petroleum Institute gravity of more than 20 degrees.

¹⁰⁴ Telephone Interview with Leonard Scandura, Supervising Air Quality Engineer, (May 21, 2008); San Joaquin Valley Air Pollution Control District Rule 2201(3.37) (2008), *available at* <http://www.valleyair.org/rules/currnrules/r2201.pdf> (last visited May 25, 2008).

¹⁰⁵ San Joaquin Valley Air Pollution Control District Rule 2201(3.37.4) (2008), *available at* <http://www.valleyair.org/rules/currnrules/r2201.pdf> (last visited May 25, 2008).

¹⁰⁶ *Id.* The question remains whether ambient standards might be a more effective means of controlling hydrogen sulfide emissions instead of aggregating sources under common corporate control, particularly as aggregation rules might simply encourage larger oil producing entities to sell off production units to circumvent regulatory standards.

¹⁰⁷ Feighner email, *supra* note 94.

¹⁰⁸ *Id.*; U.S. EPA, *Source Determinations for the Oil and Gas Industries*, Memorandum from William L. Wehrum, Acting Assistant Administrator (Jan. 12, 2007) (on file with author). Given that the states have leeway to regulate more restrictively, it is unclear whether this memorandum carries the force of law binding on the state of Michigan.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

development and includes any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed . . . After identifying the individual surface site, the permitting authority should consider aggregating pollutant-emitting activities at multiple surface sites, when the surface sites are under common control and located in close proximity to each other. A reviewing authority can consider two surface sites to be in close proximity if they are physically adjacent, or if they are separated by no more than a short distance.”¹¹¹

While the memo mentions operational dependence as a possible means of determining source status, the memo seems to favor proximity.¹¹² The presence of gravel pad sites is an indicator a permitting authority may use in designating individual surface sites. The memo also encourages permitting authorities to consider surface sites as single sources except under circumstances of proximity or interdependence.¹¹³

Overall, the logic of the memo seems to follow the general value structure traced throughout this state survey—it allows for balancing of public health and welfare against the industry’s concern of overregulation. Several surface sites in close proximity to one another could throw out large health risks upon the people who live and work near the sites, so it makes sense to aggregate them when considering the general public health and welfare. On the other hand, the interests of the E&P industry are considered by refraining from aggregating the emissions of E&P operations at some distance from one another. Such action would benefit public health, however it would likely be viewed as overly burdensome by the E&P industry.

CONCLUSION

State regulation of hydrogen sulfide emissions is an important step toward filling the gap left by the federal government’s reluctance to regulate hydrogen sulfide emitted by the industry. However, each of the states’ regulatory regimes fails to provide a comprehensive approach to the regulation of hydrogen sulfide. A more complete approach can be achieved through a combination of the various state regulatory regimes. Combining ambient standards, point source standards, and proximity restrictions will create a regulatory framework that will help protect the public from exposure to the toxic pollutant. In addition, it is essential that hydrogen sulfide, be aggregated in order to ensure the maximum regulatory protections for people whose health may be adversely affected by E&P emissions. Other non-listed toxic air pollutants emitted during oil and gas E&P could also benefit some of the techniques sketched out in this section of the survey.

¹¹¹ *Id.*

¹¹² *Id.*

¹¹³ *Id.*

Kelly Corcoran and Elizabeth Laposata, Regulating Oil and Gas Exploration and Production Waste: Common Approaches and Changing Strategies

INTRODUCTION

While the environmental effects of oil exploration, production, and use are increasingly scrutinized, the particular area of waste management is not often discussed. Meanwhile, the oil and gas industry produces billions of barrels of waste each year.¹¹⁴ Moreover, this waste is largely unregulated by the federal government; each state is responsible for controlling disposal of the different types of exploration and production (E&P) waste created by activities within its borders. Although drilling techniques and geological composition of drilling sites differ, most oil and gas producing states face large quantities of similar waste streams. As such, states have the opportunity to replicate effective waste management strategies implemented in other states. This report provides a non-exhaustive introduction to E&P waste, surveying regulation of one aspect of the E&P process, waste storage and disposal in pits, and one particular waste stream, produced water.

Section I briefly explains the types of waste frequently produced during oil and gas exploration and production activities. It continues with a description of the chemicals present in these wastes, as well as some of the public health risks associated with such chemicals, setting up Sections II and III's discussion of the impetus for state regulation. Section II highlights the values which seem to inform various state regulations, and serves as a quick reference regarding the common rules and practices implemented by the states to further these values. Analysis of regulations controlling storage and disposal of E&P wastes in pits begins Section III. Following the lifecycle of a waste pit used in the E&P process, Section III lays out both examples of regulations which are fairly standard across states and examples of more aggressive measures. Section III then focuses on regulation of the chief E&P waste streams, produced water, analyzing two produced water programs: one in California, and one in Louisiana.

I. OVERVIEW OF E&P WASTE STREAMS AND THE FEDERAL STATUTORY FRAMEWORK FOR REGULATION

A. TECHNICAL BACKGROUND

Oil exploration and production activities generate at least three main waste streams¹¹⁵: drilling muds and cuttings, associated wastes, and produced water. As a well is drilled, pieces of rock break away in the hole; these are called drill cuttings. Drill cuttings are often brought to the

¹¹⁴ See Argonne National Laboratory Environmental Sciences Division, *Offsite Commercial Disposal of Oil and Gas Exploration and Production Waste: Availability, Options, and Costs* 1, t.1 (2006) [hereinafter "Argonne, *Offsite Disposal*"].

¹¹⁵ R.L. Petrusak, B.D. Freeman, and G.E. Smith, "Baseline Characterization of U.S. Exploration and Production Wastes and Waste Management," abstract available at <http://cat.inist.fr/?aModele=afficheN&cpsid=6173085> (last visited Dec. 3, 2008). Other waste streams include other post-drilling chemicals, including corrosion inhibitors and biocides.

surface by inorganic drilling muds,¹¹⁶ circulated to cool and lubricate the drill bit. During the drilling phase of operations, a pit is often created to store used drilling muds and cuttings brought to the surface; these pits are called drilling or reserve pits. Associated wastes are any other wastes created in the process, such as hydraulic fracturing fluids and contaminated soil. Operators use the process of hydraulic fracturing, or injecting fluids into rock formations, to cause cracks in the formations which allow oil and gas to flow more freely to the production well. Once production begins, hydraulic fracturing fluids are, for the most part, pumped to the surface along with the oil, gas, and produced water, and stored in pits or tanks.¹¹⁷

Produced water is water that is extracted from a well along with the oil and gas. Produced water normally refers to naturally-occurring fluids, often saline fluids, rather than treatment materials. During the process of actually extracting the oil from the well, produced water pits are created to store water that is extracted along with the oil; these are termed production pits. Pits that are used to permanently dispose of produced water are called evaporation pits. With increasing frequency, tanks rather than pits are used to hold and dispose of produced water.

E&P operations generate prodigious amounts of produced water.¹¹⁸ It is produced along side oil at a ratio of 9:1 water to oil, and later separated out.¹¹⁹ In 1995, the volume of produced water generated in California alone was estimated to be about 1,684,200,000 barrels.¹²⁰ In 2006 the volume of produced water generated in Colorado alone from coal bed methane production was estimated at 388,385,119 barrels.¹²¹ The quality and constituents of produced water are determined by the minerals present in the location and the formation surrounding the produced water.¹²² The oil and produced water are hot and under pressure when underground so they pull out minerals and other chemicals from the surrounding formation with it.¹²³

1. Contaminants in E&P Wastes

¹¹⁶ Christopher J. Burke, and John A. Veil, "Synthetic-based drilling fluids have many environmental pluses," *Oil & Gas Journal*. Vol. 95, Issue 48 (Nov. 27, 1995). The article mentions three different types of drilling mud: synthetic-based, oil-based, and water-based. Even the water-based muds are chemical compounds, comprised of 90% water, with barite, clays, lignosulfonate, lignite, caustic soda, and other specialty additives depending on specific well conditions. For example, bentonite, a volcanic clay, is used to increase mud viscosity and help lift drill cuttings. Oil-based muds include: base oil (usually diesel or mineral oil), barite, clays, emulsifiers, water, calcium chloride, lignite, lime, and other additives. Synthetic-based muds may be made from alcohols, fatty acids, 1-octene, 1-decene, and normal alphaolefin.

¹¹⁷ Earthworks, *Hydraulic Fracturing 101*, <http://www.earthworksaction.org/FracingDetails.cfm> (last visited January 14, 2009).

¹¹⁸ U.S. EPA, Office of Compliance, *Profile of the Oil and Gas Extraction Industry* (October 2000), available at <http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oil.html>.

¹¹⁹ See U.S. EPA, *Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations*, <http://www.epa.gov/osw/nonhaz/industrial/special/oil/oil-gas.pdf> (last visited Dec. 1, 2008) [hereinafter, "U.S. EPA, *Exemption of Oil and Gas From Federal Regulations*"].

¹²⁰ *Id.*

¹²¹ Earthworks, *OGAP 2007 Produced Water Factsheet: Options and Costs for Disposal of Produced Water*, <http://www.earthworksaction.org/pubs/MicrosoftwordProducedWaterFactsheet2.pdf> (last visited May 16, 2008).

¹²² Telephone interview with Marilu Habel, Associate Engineer, California Division of Oil, Gas and Geothermal Resources (April 1, 2008).

¹²³ *Id.*

Oil and gas exploration and production wastes may contain a variety of chemicals and pollutants. The most prevalent contaminants are the group of volatile organic compounds (VOCs) known as BTEX: benzene, toluene, ethylbenzene, and xylenes.¹²⁴ Exposure to ethylbenzene and benzene can occur from air or water. High amounts of benzene can cause leukemia, and long term exposure to ethylbenzene can result in kidney damage.¹²⁵ Toluene exposure in the public mainly occurs from contaminated water or if living near uncontrolled contaminated sites and can result in nervous system damage. Xylene breaks down easily so exposure comes mostly from eating fish, shellfish and plants living in water contaminated with xylenes. High level exposure to xylenes can cause dizziness, headaches and loss of balance among other problems.¹²⁶

There are several contaminants of concern, including other VOCs, from E&P wastes. Several naturally occurring metals, such as barium, lead and cadmium, are also present in E&P wastes. Produced water also has the possibility of containing Naturally Occurring Radioactive Materials (NORM).¹²⁷ The presence of so many possible contaminants in E&P wastes illustrates the importance of regulation of these waste products, and may explain the variety of regulatory techniques utilized to address the disparate risks in different media.

2. *Methods of Disposal*

With the varying types of waste produced in E&P operations, the industry has developed, and states have attempted to maintain regulation of, various methods for disposing of E&P wastes. The chart below provides an overview of common disposal techniques.

Disposal Technique	Wastes Disposed of by Technique	Effect of Method of Disposal
Pits	Drilling wastes, produced water, production fluids and wastes	Permanent disposal of drilling wastes
Landfills	Drilling wastes	Permanent disposal of drilling wastes
Landfarms	All possible wastes	Temporary storage and treatment of waste using repeated applications of waste to soil and soil microorganisms to break down hydrocarbons
Land Spreading	All possible wastes	Disposal and treatment of waste using one-time application of waste to soil and soil microorganisms to break down hydrocarbons

¹²⁴ See USGS, “Toxic Substances Hydrology Program: BTEX,” <http://toxics.usgs.gov/definitions/btex.html> (last visited May 16, 2008).

¹²⁵ *Id.*

¹²⁶ *Id.*

¹²⁷ See Claudia Zagrean Nagy, *Oil Exploration and Production Wastes Initiative* (Dep’t of Toxic Substances Control, 2002).

Thermal Technologies	All possible wastes	Use of high temperatures to break down hydrocarbons. Sometimes care needed afterward for removal of metals and salts
Underground (Slurry) Injection	Waste solids ground with water to create a slurry	Permanent disposal of drilling wastes underground
Salt Caverns	Larger waste solids ground with water to create a slurry	Permanent disposal of larger drilling wastes underground

Sources: *Earthworks and Argonne National Laboratory*¹²⁸

Operators report that they dispose of over 99% of E&P waste themselves, either at or near the oilfield, or at a centralized facility.¹²⁹ Centralized facilities are maintained by one operator and may collect waste from multiple wells under the control of that operator. Unlike centralized facilities, commercial facilities are run by a third-party and accept waste from several operators for a fee. Most states do not have commercial facilities unique to the oil and gas industry, but rather permit other waste disposal facilities to accept E&P wastes.¹³⁰ Because only a very small percentage of E&P wastes are transferred to commercial disposal facilities, this paper does not substantially address states' approaches to regulating the various commercial disposal facilities that may accept E&P waste.

B. FEDERAL LAW REGARDING E&P WASTES

1. *The Resource Conservation and Recovery Act*

The Resource Conservation and Recovery Act (RCRA) regulates solid waste, hazardous waste, and underground storage tanks from "cradle to grave." One of the main purposes of RCRA is to assist states and local governments in creating their own comprehensive waste management plans.¹³¹ Thus, RCRA explicitly provides that while states are prohibited from imposing less strict requirements for waste management, states may make laws and regulations more stringent than those mandated under RCRA.¹³² Currently, all 50 states have authority to implement some part of the RCRA program.¹³³ EPA requires states to adhere to certain terms and conditions including directing the states to develop waste management plans and submit these plans to the Federal government for approval and financial assistance.¹³⁴

¹²⁸ See Earthworks, *Oil and Gas Waste Disposal*, <http://www.earthworksaction.org/oilgaswastedisposal.cfm> (last visited May 16, 2008) and Argonne National Laboratory, *Drilling Waste Management Technology Descriptions*, <http://web.ead.anl.gov/dwm/techdesc/index.cfm> (last visited May 16, 2008).

¹²⁹ Argonne, *Offsite Disposal*, 10, t.4 (2006).

¹³⁰ *Id.*

¹³¹ 42 U.S.C. § 6902(a)(1) (2005).

¹³² *Id.* § 6929.

¹³³ U.S. EPA, "RCRA State Authorization," <http://www.epa.gov/osw/laws-regs/state/> (last visited Dec. 3, 2008).

¹³⁴ 42 U.S.C. § 6947. See also James R. Cox, "Revisiting RCRA's Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes," XIV VILLANOVA ENVTL. L. J. 1, 31 (2003). See also U.S. EPA, "RCRA State Authorization," *supra* note 131.

RCRA regulations expressly exclude “drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy” from the definition of “hazardous waste.”¹³⁵ “Other wastes associated” means “intrinsically derived from the primary field operations,” as opposed to transportation and manufacturing operations.¹³⁶ The exclusion of these materials does not mean that they are not hazardous.¹³⁷ According to EPA, the exemption is designed to accommodate the large volume of E&P waste: the RCRA system would have been overwhelmed and the economic impact to the oil and gas industry would have reduced production.¹³⁸ The excluded materials may nevertheless be subject to other federal laws, as well as state laws.

2. Clean Water Act

The Water Pollution Act, more commonly known as the Clean Water Act, protects the quality of the nation’s waterways. The Clean Water Act controls discharges to surface water directly from industrial sources. Under several sections of the act, before discharging certain E&P wastes, operators must obtain permits from the authority designated in the CWA. Section 404 of the Clean Water Act requires the Army Corps of Engineers to issue permits for the discharge of dredged or fill material into the waters of the United States. Section 401 requires that the states issue permits for the discharge of dredged or fill material into the waters of the United States.¹³⁹ Finally, section 402 requires a National Pollutant Discharge and Elimination System (NPDES) permit for discharges into the waters of the United States; however section 402 excludes storm runoff from oil and gas facilities if it does not come into contact with any other contaminated material.

3. Safe Drinking Water Act and the Underground Injection Control Program

The Safe Drinking Water Act (SDWA) protects the health and safety of the public from contaminants in the nation’s drinking water supply. The EPA works in conjunction with states on compliance of EPA created drinking water standards. Also, through the SDWA, the EPA regulates the underground injection of oil and gas exploration and production wastes through the Underground Injection Control (UIC) program.¹⁴⁰

Congress required the implementation of the UIC program as part of the SDWA in order to prevent contamination of underground drinking water sources by the fluids injected underground.¹⁴¹ The UIC sets up minimum standards for underground injection, requiring that all injected fluids stay within the drilled well and that injection of the fluids not cause any drinking water source to be in violation of safe drinking water standards.¹⁴² Implementation of

¹³⁵ 40 C.F.R. § 261.4(b)(5).

¹³⁶ U.S. EPA, *Exemption of Oil and Gas From Federal Regulations*, *supra* note 117.

¹³⁷ *Id.*

¹³⁸ Nagy, *supra* note 125.

¹³⁹ U.S. EPA, *Exemption of Oil and Gas From Federal Regulations*, *supra* note 117.

¹⁴⁰ *Id.*

¹⁴¹ U.S. EPA, *Underground Injection Control Program: Basic Information about Injection Wells*, <http://www.epa.gov/safewater/uic/basicinformation.html> (last visited May 16, 2008).

¹⁴² *Id.*

the UIC program is left up to the states if they choose and if they meet the primary requirements of the UIC program.¹⁴³

The UIC program breaks wells up into five different regulation categories. Class II wells are fluid injection wells associated with oil and gas E&P.¹⁴⁴ There are three different types of Class II injection wells; enhanced recovery, disposal, and hydrocarbon storage wells.¹⁴⁵ This section of the survey will discuss only disposal type wells when discussing wells.

4. Clean Air Act

The Clean Air Act (CAA) regulates air quality and air emissions. The Act requires compliance with the National Emission Standards for Hazardous Air Pollutants specific to oil and gas exploration and production.¹⁴⁶ Additionally, stationary sources with a threshold amount of certain regulated substances must have a Risk Management Program which includes a hazard assessment and an emergency preparedness plan.¹⁴⁷ Oil and gas production and exploration is exempt from the Clean Air Act aggregation requirement that groups together smaller sources of hazardous pollutants for emission control. Additionally, hydrogen sulfide, routinely emitted in significant amounts from oil and gas wells, was removed from the original list of hazardous air pollutants regulated by the Clean Air Act.¹⁴⁸

II. VALUES WHICH SHAPE STATE REGULATORY PRACTICES

A state's geography, population, amount of oil and gas activity, fiscal resources, and industry influence may all drive its regulatory framework. Nevertheless, waste management standards across states tend to reflect, in varying degrees, a pursuit of recognizable, common policy goals. The following chart lays out the values states explicitly or tacitly pursue, as well as the regulatory practices which result.

Values	Practices
Protecting groundwater from contamination	<ul style="list-style-type: none"> ◦ Pit location requirements—distance above water table and away from surface water ◦ Pit liners ◦ Required testing of wastes before disposal ◦ Well construction and pressure requirements for disposal of produced water

¹⁴³ U.S. EPA, *Underground Injection Control Program: Oil and Gas Related Injection Wells (Class II)*, http://www.epa.gov/safewater/uic/wells_class2.html#what_is (last visited May 16, 2008).

¹⁴⁴ *Id.*

¹⁴⁵ *Id.*

¹⁴⁶ The Clean Air Act (CAA) is discussed in much greater detail in the hydrogen sulfide section. Notably, some E&P byproducts, particularly hydrogen sulfide, are not listed as hazardous air pollutants, and thus are regulated, if at all, by state standards.

¹⁴⁷ See CAA, § 112(r); also, U.S. EPA, "Risk Management Plan," <http://www.epa.gov/emergencies/content/rmp/index.htm> (last visited Dec. 3, 2008).

¹⁴⁸ Mall, *Drilling Down*, *supra*, note 41.

Safeguarding wildlife from injury and mortality	<ul style="list-style-type: none"> ◦ Prohibitions on oil floating in pits ◦ Fencing and netting of pits ◦ Immediate closure of onsite pits
Protecting general public health	<ul style="list-style-type: none"> ◦ Air emissions regulations ◦ Setbacks from residences, hospitals, schools, and other buildings ◦ Odor and dust regulations ◦ Permitting requirements for disposal or discharge into waters
Limiting unexpected pollution and contamination	<ul style="list-style-type: none"> ◦ Expanded planning requirements ◦ Testing of waste before disposal
Minimizing waste	<ul style="list-style-type: none"> ◦ Closed-loop systems ◦ Recycling of waste
Promoting efficiency	<ul style="list-style-type: none"> ◦ Economic incentives for cleaner waste management resulting in a decrease of agency monitoring

III. DEVELOPMENTS IN STATE REGULATION

A. STORAGE AND DISPOSAL OF E&P WASTES IN PITS¹⁴⁹

1. Planning, Siting Limitations, and Construction Requirements

(i) Pit permitting requirements

Most state oil and gas commissions require operators to obtain separate permits for the construction and use of pits, in addition to normal drilling permits. The permit applications tend to be quite short, approximately one page. Information requested on permit applications focuses on the technical aspects of the pit: the pit's size and volume; the liner thickness and type, if any; the depth from the bottom of the pit to groundwater; the distance from the pit to surface water or a wellhead; the type of mud system that will be used during drilling; and the waste streams entering the pit.¹⁵⁰

States with recently updated, or proposed updates to their permitting applications are demanding that applicants more fully anticipate and prepare for the consequences of their operations. In Pennsylvania, which last updated its pit construction permit application in 1998, applicants must submit an operation and maintenance plan, as well as a closure and restoration plan.¹⁵¹ Additionally, Pennsylvania operators must detail how they will dispose of the liquid and solid waste from its operations, including the method, the location, and the hauler, if applicable.¹⁵²

¹⁴⁹ This report was prepared while Colorado and New Mexico were engaged in the rule amendment process. Differences between the proposed and adopted rules are noted when relevant.

¹⁵⁰ See e.g., COLO. OIL AND GAS CONSERVATION COMM'N, Form 15; MONT. DEP'T OF NATURAL RES. BD. OF OIL AND GAS CONSERVATION, Form No. 23; N.M. ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., Form C-144; PENN. DEP'T OF ENVTL. PROT., BUREAU OF OIL AND GAS MGMT., Form 5500-PM-OG0072 and 25 PA. CODE § 78.57 (1989).

¹⁵¹ PENN. DEP'T OF ENVTL. PROT., BUREAU OF OIL AND GAS MGMT., Form 5500-PM-OG0072.

¹⁵² *Id.*

Likewise, New Mexico strengthened its permitting standards, requiring that an engineer certify the design plans, including the operating and maintenance plan, closure plan, and emergency response plan.¹⁵³ Moreover, New Mexico's new permitting rules applicable to permanent and temporary pits also require that engineers provide a hydrogeological report, detailing the site's topography, soils, geology, surface hydrology and ground water hydrology.¹⁵⁴ Colorado currently requires that operators applying for a permit to construct production pits, centralized facilities, and certain reserve pits make "sensitive area determinations" to evaluate the potential impact on groundwater. Under Colorado's recently adopted rules, operators also have to evaluate the potential impact of the waste system on surface water.¹⁵⁵ Montana and Wyoming, moreover, require that an operator include a an analysis of nearby water sources along with its application, presumably so that comparative testing may be performed at cessation of the operations.¹⁵⁶

In order to combat the increased risks and consequences of contamination associated with centralized and commercial pits, states tend to have more stringent permitting, construction, and operation requirements for centralized facilities. Upon review of their regulatory frameworks, New Mexico and Colorado appear to have the most detailed, and explicit, permitting requirements for centralized facilities.¹⁵⁷ Both require topographic, geologic, and hydrologic descriptions of the proposed site, a complete site plan, an operation plan, an inspection plan, an emergency plan, and a closure plan.¹⁵⁸ Even prior to recent amendments, New Mexico required centralized and commercial facilities that dispose of E&P wastes to provide baseline analyses of the closest sources of groundwater, measuring levels of chloride, fluoride, sulfate, sodium, BTEX, certain metals, and total dissolved solids.¹⁵⁹

Colorado's recently adopted regulations expand upon its current requirements of basic description and planning for centralized facilities. The rules detail particular geologic, hydrologic, and engineering data necessary for permitting, including the character of the surrounding soil, the facility's relationship to nearby surface and groundwater, the facility's potential impact on those waters, and methods for diversion.¹⁶⁰ At application, facility operators will also need to report on the nearby baseline water well quality.¹⁶¹

(ii) *Siting requirements*

Protection of ground, surface, and drinking waters informs much state regulation of oil and gas pits. Many states prohibit operators from engaging in any oil and gas activities within a

¹⁵³ N.M. CODE R. § 19.15.17.9(B) (2008).

¹⁵⁴ *Id.* §§ 19.15.17.9(B)(1)(d); 19.15.17.9(B)(2).

¹⁵⁵ 2 COLO. CODE REGS. § 401-1-901(e) (2008).

¹⁵⁶ MONT. DEP'T OF NATURAL RES. BD. OF OIL AND GAS CONSERVATION, Form No. 23; WYO. OIL AND GAS CONSERVATION COMM'N DOC. NO. 6855.

¹⁵⁷ The New Mexico and Colorado regulations governing centralized facilities apply to the facility as a whole, rather than only to centralized pits. Other waste storage and disposal units at centralized facilities may include tanks or buildings.

¹⁵⁸ N.M. CODE R. § 19.15.36.8 – 19.15.36.14, 19.15.36.17 (2008); 2 COLO. CODE REGS. § 401-1-908(b) (2008).

¹⁵⁹ N.M. CODE R. § 19.15.36.8(C)(15)(b).

¹⁶⁰ 2 COLO. CODE REGS. § 401-1-908(b)(7) (2008).

¹⁶¹ *Id.* § 401-1-908(b)(9).

certain proximity to particularly sensitive natural environments. In an effort to decrease the likelihood, and minimize the effects, of pit contents interfering with protected environments and public health, specific minimum distance requirements applicable to pits exist in some states. These establish, for example, the distance above groundwater tables a pit must be located, the distance between pits and streams or other surface waters, and the distance between pits and homes and other buildings. A few states insist that the groundwater table lay not less than several (4-5) feet below the bottom of an oilfield pit. As mentioned above, Wyoming insists that operators use closed-loop drilling systems, rather than pits, when the groundwater is less than 20 feet below the surface.¹⁶² New Mexico, however, limits pits to locations at least 50 feet above groundwater, consistent with its current limitations for commercial disposal facilities.¹⁶³

When permitting pits and drilling sites, states may evaluate the distances between proposed operations and surface and drinking waters.¹⁶⁴ A few states are explicit about the minimum distances required between pits and surface water or drinking water sources. In Pennsylvania, pits must be located at least 100 feet from a stream, wetland, or other body of water.¹⁶⁵ Previously, New Mexico only required that pits not be located *in* any watercourse, lakebed, sinkhole, playa lake, or wetland.¹⁶⁶ As with most pit regulations, New Mexico has recently adopted more specific and stringent requirements. Under the new rules, pits in New Mexico must be located not less than 300 feet from any continuously flowing watercourse, or 200 feet from most other bodies of water; not less than 500 feet from a water source that serves fewer than 5 households for domestic or stock purposes, or 1000 feet from any other fresh water well or spring; and not less than 500 feet from a wetland.¹⁶⁷ Municipal water supplies are also protected under the new rules.¹⁶⁸

Some states recognize that oil and gas operations, and pits in particular, can affect public health beyond water contamination. One step evidencing this understanding is implementation of siting requirements that establish the distance between pits and community destinations—for example, homes, schools, hospitals, recreation areas. For example, Colorado now requires that in high density areas production equipment, such as pits, be located at least 350 feet from a normal building, but 500 feet from, among other things, any school, hospital, nursing home, or designated outdoor activity area.¹⁶⁹ Following this lead, New Mexico new rules mandate that

¹⁶² WYO. OIL AND GAS CONSERVATION COMM’N DOC. NO. §4-1(u) (2008).

¹⁶³ N.M. CODE R. § 19.15.17.10(A)(1)-(2) (2008).

¹⁶⁴ An oil and gas commission, water board, or other permitting board’s discretion to consider distance to surface water is often made plain in the substantive statute or regulation. *See, e.g.*, KAN. ADMIN. CODE § 82-3-600(c) (2004); WYO. OIL AND GAS CONSERVATION COMM’N DOC. NO. §4-1(u) (2008).

¹⁶⁵ 25 PA. CODE § 78.57

¹⁶⁶ N.M. CODE R. § 19.15.2.50(C)(2)(a) (2004).

¹⁶⁷ N.M. CODE R. §19.15.17.10(A)(1)-(2) (2008).

¹⁶⁸ *Id.* §19.15.17.10(A)(1)(e).

¹⁶⁹ 2 COLO. CODE REGS. § 404-1-603(e) (2008). According to the rules, “[a] high density area shall be determined at the time the well is permitted on a well-by-well basis by calculating the number of occupied building units within the seventy-two (72) acre area defined by a one thousand (1000) foot radius from the wellhead or production facility. If thirty-six (36) or more actual or platted building units (as defined in the 100 Series rules) are within the one thousand (1000) foot radius or eighteen (18) or more building units are within any semi-circle of the one thousand (1000) foot radius (i.e., an average density of one (1) building unit per two (2) acres), it shall be deemed a high density area. If platted building units are used to determine the density, then fifty percent (50%) of said platted units shall have building units under construction or constructed.” *Id.* § 404-1-603(b).

temporary pits be located at least 300 feet from any home, school, hospital, institution or church, and that permanent pits be located at least 1000 feet from the same.¹⁷⁰ Colorado also recently adopted a rule requiring that every produced water pit be located at least 200 feet from any building, even in non-high density areas.¹⁷¹

Furthermore, Colorado's proposed regulations held that pits with the potential to emit more than two tons per year of volatile organic compounds may not be located within one half mile of essentially any building or outdoor area likely to be consistently used by the public.¹⁷² Colorado is one of the few states that explicitly addresses, or is attempting to explicitly address, the potential impacts open pits may have on air quality. In general, pits are considered as any other new source, meaning that they are subject to ambient air quality standards, odor rules, and fugitive emissions rules. California also addresses the air quality issues posed by open pits: local air resource boards have taken the lead in regulating open pits. The San Luis Obispo and San Joaquin Valley Air Pollution Control Districts regulate certain production pits, providing that most production pits must have covers that control the escape of volatile organic compounds.¹⁷³

(iii) *Pit liner requirements*

An important way in which states protect groundwater is by requiring that pits be lined. Though a few states still do not require all pits be lined, when liners are required, the general practice is to demand the use of a liner which is "impervious, weather resistant and resistant to deterioration when in contact with hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water."¹⁷⁴ Liner requirements are increasingly specific, demanding that the liners be made from certain materials and be of a sufficient thickness. To the extent that synthetic, rather than soil, liners are used in Pennsylvania, the Oil and Gas Commission requires that liners have a thickness of 30 mils, approximately 3/1000 of an inch.¹⁷⁵ Admittedly, 30 mils appears thin, but the few other states which have specifically addressed liner thickness have standards ranging from 9 mils to 20 mils. Again recognizing the risks of centralized and commercial pits, Colorado proposed that centralized E&P waste facilities line pits with materials of at least 60 mils.¹⁷⁶

¹⁷⁰ N.M. CODE R. § 19.15.17.10(A)(1)-(2) (2008).

¹⁷¹ 2 COLO. CODE REGS. § 404-1-604(f) (2008).

¹⁷² 2 COLO. CODE REGS. § 404-1-805(b)(2)(D) (proposed March 31, 2008). The final amended rules, however, prohibit operators from constructing new pits that have the potential to emit more than *five* tons per year of VOCs within *one-quarter* mile of certain buildings and areas. This limitation applies only to new pits in three Colorado counties. 2 COLO. CODE REGS. § 404-1-805(b)(2)(D) (2008). Oil and gas operations must still be in compliance with the Department of Public Health and Environment, Air Quality Control Commission, Regulation No. 2 Odor Emission, 5 COLO. CODE REGS. § 1001-4. *Id.* § 404-1-805(b)(1)(A).

¹⁷³ San Joaquin Valley Unified Air Pollution Control District Rule 4402 (1992); San Luis Obispo County Air Pollution Control District Rule 419 (1994).

¹⁷⁴ *See, e.g.*, UTAH ADMIN. CODE § 649-9-3:2.3.9 (2008).

¹⁷⁵ OKLA. ADMIN. CODE § 165:10-7-16(c)(7)(A) (2008).

¹⁷⁶ 2 COLO. CODE REGS. § 404-1-904(b)(4) (proposed March 31, 2008). While Colorado's final amended rules retain the 60 mils requirement, the thickness requirement for centralized facility and single-well pits, under the final rules, operators gained the opportunity to demonstrate to the Director of the Oil and Gas Commission that its liner system offers "equivalent protection to public health, safety, and welfare." 2 COLO. CODE REGS. § 404-1-904(c) & (d) (2008).

Leak detection systems provide an additional means of protecting groundwater. Nevertheless, few states require the use of leak detection systems in pits. In Colorado, only in sensitive areas may the Director of the Oil and Gas Commission require leak detection systems.¹⁷⁷ New Mexico, which currently insists that operators fit storage and disposal pits (rather than drilling/reserve pits) with two liners, also demands that operators install a leak detection system between the two liners.¹⁷⁸

2. Operations and Final Disposal

States limit the types of waste that may be placed in reserve, production, and disposal pits. Commonly, states require that pit waste must be RCRA-exempt. Because this kind of waste has been characterized as non-hazardous under RCRA, the states are the only possible regulatory authority. Because almost all states follow the RCRA exemption, however, this means that almost all E&P waste may be placed in open pits. States do exclude some types of E&P waste from the RCRA exemption: unused drilling fluids, soil contaminated by particular chemicals, used hydraulic fluids, and unused well completion fluids.¹⁷⁹

(i) Limits on disposal

Nevertheless, a few states further limit the type of waste which may be stored and disposed of in pits. In Michigan, operators may only place certain drilling materials in pits—water-based muds and cuttings, and certain muds and cuttings from particular drilling locations, native soils, and solidification materials.¹⁸⁰ Machine oil, refuse, completion and test fluids, liquid hydrocarbons, or solid salt cuttings may not be placed in pits in Michigan.¹⁸¹ Likewise, Wyoming requires that operators remove solids with high salt concentrations from pits before burial.¹⁸² Oil-based muds must also be taken to a commercial facility or mixed with soil until it the mixture is at designated oil content levels.¹⁸³

(ii) Pit covers

The federal government and wildlife protection organizations have identified, and most states have implemented, several procedures applicable to oil and gas pits. Preventing access to pits, or at least contact with oil-covered pits drives the regulations. Methods of protecting wildlife include prohibiting the accumulation of oil and oil sheens on top of pit contents, requiring fencing, and requiring netting. In 2003, the Region 8 section of the EPA reported on pits in Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming. The states with the highest percentage of pits free of oil were North and South Dakota.¹⁸⁴ Perhaps because the Dakotas have the lowest number of pits, neither has strict pit skimming regulations. The EPA reported that Wyoming, with the most pits overall, had the third highest percentage of pits free of

¹⁷⁷ 2 COLO. CODE REGS. § 404-1-904(e) (2008).

¹⁷⁸ N.M. CODE R. § 19.5.17.11(G)(2) (2008).

¹⁷⁹ Argonne, *Offsite Disposal*, *supra* note 127, at 5 t.3.

¹⁸⁰ MICH. ADMIN. CODE § 615.324.407(7)(b) (1996).

¹⁸¹ *Id.* §§ 615.324.407(7)(a) & (d) (1996).

¹⁸² WYO. OIL AND GAS CONSERVATION COMM'N DOC. NO. §4-1(ii)(iv) (2008).

¹⁸³ *Id.* §4-1(ii)(v) (2008).

¹⁸⁴ U.S. EPA REGION 8 OIL AND GAS ENVIRONMENTAL ASSESSMENT EFFORT 1996 – 2002 p.7 t.2 (2003).

oil. Interestingly, Wyoming demands that operators remove any oil from pits within 10 days of *discovery*.¹⁸⁵ Behavior of operators in North Dakota and Wyoming may be explained by the fact that when oil is present in a pit, each state requires operators to install nets over pits. Even though the 10 day after discovery limitation may discourage operators from “discovering” oil, the desire to avoid netting seems to encourage operators to keep pits free of oil.

Nevertheless, because wildlife may be injured by pit contents other than visible oil, other states require consistent netting of pits.¹⁸⁶ Moreover, most states have fencing schemes applicable to pits to protect both the public and wildlife other than birds. New Mexico and Wyoming provide that operators fence reserve and production pits, while Utah provides that all permanent disposal pits must be fenced.¹⁸⁷ Michigan requires that operators either close pits immediately after drilling activities cease or fence them.¹⁸⁸

(iii) Closure of pits

The final way in which states regulate oil and gas pits is by implementing closure requirements. One element of closure requirements is often time limitations. Some states allow pits to remain open up to several years, but Michigan requires that reserve pits be closed as soon as practicable, but at least within 6 months of the cessation of drilling activities, whether or not the pits have been fenced in the interim.¹⁸⁹ New Mexico’s new regulations also require that temporary pits be closed within 6 months.¹⁹⁰

As with construction plans, states are increasingly requiring that operators obtain approval of detailed closure and post-closure plans before pits may be closed. In conjunction with closure plans, several states require analysis of wastes before they are permanently encapsulated. Operators in Michigan must report the levels of BTEX in the pit contents before burial.¹⁹¹ Louisiana requires that operators of most wells test pit contents for various concentrations, including metals and inorganics, provides maximum levels for materials to be buried; Louisiana does not require testing for organic compounds.¹⁹² In addition to testing the pit contents, some states require that operators analyze the soil and water quality in areas surrounding the pit.¹⁹³ Testing of soil and water quality surrounding disposal sites is standard with closing of centralized and commercial facilities.¹⁹⁴

3. Rethinking Waste

¹⁸⁵ See, e.g., WYO. OIL AND GAS CONSERVATION COMM’N DOC. NO. 6885 §4-1(dd) (2008).

¹⁸⁶ See, e.g., N.M. CODE R. § 19.5.17.11(E) (2008).

¹⁸⁷ N.M. CODE R. § 19.5.17.11(D) (2008). ; UTAH ADMIN. CODE § 649-9-3-2.3.6 (2008).

¹⁸⁸ MICH. ADMIN. CODE § 615-324-407(8) (1996).

¹⁸⁹ *Id.* § 615-324-407(9)(c) (1996).

¹⁹⁰ N.M. CODE R. § 19.15.17.13(A) (2008).

¹⁹¹ MICH. ADMIN. CODE § 615.324.407(7)(e) (1996).

¹⁹² LOUIS. ADMIN. CODE tit. 43-XIX § 311(C) (2007) (Statewide Order No. 29-B).

¹⁹³ See, e.g., 2 COLO. CODE REGS. § 401-1-910 (2008).

¹⁹⁴ See, e.g., OKLA. ADMIN. CODE § 165:10-9-1 (1992).

Operators have begun to use new drilling systems that eliminate the need for reserve, or drilling, pits; these are called closed-loop, or closed-mud drilling systems.¹⁹⁵ However, motivation to adopt these new drilling techniques has not come from state mandates. Rather than demanding that operators use pitless drilling methods, several states acknowledge and encourage the practice. Texas, New Mexico and Illinois all issue best practices guides for oil and gas producers, agreeing that closed-loop drilling systems are useful alternatives to traditional drilling with reserve pits. Colorado's new regulations require pitless drilling for operations within certain designated areas that could affect a drinking water supply system.¹⁹⁶ Further, the New Mexico Oil and Gas Commission seems to recognize the potential for increased use of closed-loop systems. The Commission's new rules explicitly approve of closed-loop systems, and lay out the permitting, operation, and closure requirements for closed-loop systems that are less procedurally demanding than those for pits.¹⁹⁷

Wyoming is one state which does mandate the use of closed-loop systems, at least in limited circumstances—in areas where groundwater is less than 20 feet below the surface.¹⁹⁸ While few states currently require closed-loop systems, even in sensitive areas, Oil and Gas Commissions generally have the discretion to demand that operators implement different environmental and public health safeguards depending on the unique aspects of an oilfield. Thus, although Wyoming's closed-loop system mandate is narrow, Wyoming explicitly gives discretion to its Oil and Gas Commission to require the use of closed systems when operations will occur near water supplies, homes, schools, hospitals or other similar locations.¹⁹⁹

Simply limiting produced water disposal options is another way that states may address concerns regarding the environmental and public health effects of produced water in particular. Indiana explicitly prohibits the use of evaporation pits for permanent disposal of produced water.²⁰⁰ Before produced water is placed in a production pit or disposed of by evaporation in Colorado, it must be treated so that it does not contain hydrocarbons.²⁰¹ Oklahoma provides that produced water may be disposed of by reclamation and/or recycling, injection, or permitted discharge (after testing).²⁰² Oklahoma also provides that no pit can be used for the permanent storage of saltwater.²⁰³ The next section evaluates in greater detail more specific means of dealing with produced water.

B. DISPOSAL OF PRODUCED WATER

Produced water can be disposed of in any of the above-mentioned methods, though underground injection and discharge into waterways per the Clean Water Act are the most common methods of disposal. Generally, produced water is relatively clean and contains low

¹⁹⁵ See OIL AND GAS ACCOUNTABILITY PROJECT, CLOSED-LOOP DRILLING SYSTEM: A COST-EFFECTIVE ALTERNATIVE TO PITS, available at http://www.emnrd.state.nm.us/ocd/documents/2007_0110OGAP.pdf.

¹⁹⁶ 2 COLO. CODE REGS. § 401-1-317B(d)(1) (2008).

¹⁹⁷ N.M. CODE R. §§ 19.15.17.8 - 19.15.17.13 (2008).

¹⁹⁸ WYOM. ADMIN. CODE §4-1(u) (2008).

¹⁹⁹ *Id.*

²⁰⁰ 312 IND. ADMIN. CODE § 16-5-13(b) (2008).

²⁰¹ 2 COLO. CODE REGS. §§ 404-1-902(h), 404-1-907(c)(1) (2007).

²⁰² OKLA. ADMIN. CODE § 165:10-7-24(b)-(c) (2002).

²⁰³ *Id.* § 165:10-7-20(c)(5) (2006).

amounts of chemicals; however there is still reason for concern about contamination. Produced water may be extremely saline, will contain oil and gas constituents and may carry with it chemicals added during the drilling and separation.²⁰⁴ When the oil and produced water are brought above ground, they cool and are depressurized, which causes impurities to settle out.²⁰⁵ The produced water is sent through a series of tanks to separate out the oil or gas.²⁰⁶ If not properly cleaned and maintained, these tanks can build up chemicals and sludge at the bottom.²⁰⁷ Over time, these settled chemicals can be reabsorbed into the produced water. The levels of chemicals in produced water may differ depending on the method used, for example, BTEX levels in produced water from gas production is higher than levels found in oil production.²⁰⁸ Because this produced water is usually pumped back underground or into waterways, there is real concern about the possibility of contamination of groundwater and other waterways with BTEX chemicals. There are several places along the process where states may require testing. This section examines states' measures imposed upon the disposal of produced water. There are a few places during the lifecycle of produced water where states may regulate to prevent contamination of ground and surface water. California is the only state that takes regulatory steps before the disposal of produced water, and Louisiana, like most states, regulates for the protection of the environment at the time of injection by administering the UIC program.²⁰⁹ Regulation after injection is a step that no state has taken yet.²¹⁰ Some states might regulate further at the time of capping and abandoning of wells, a topic which is not discussed here.²¹¹

1. Regulation of Produced Water Before Disposal: California

(i) Testing of produced water

California is the only state to take steps prior to the disposal of produced water to ensure the safety of groundwater.²¹² These steps fill in some of the gaps present from RCRA exemptions. California has federal authorization to implement RCRA, and has adopted most, but not all, of the E&P exemption.

California takes additional steps beyond RCRA in the classification of waste.²¹³ California requires operators to conduct testing of produced water, to determine whether it's exempt or not. In order to determine if the waste is exempt from hazardous waste regulations, California's Department of Toxic Substances Control (DTSC) goes through a series of

²⁰⁴ John Veil, Markus Puder, Deborah Elcock and Robert Redweik, A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane (Argonne National Laboratory, 2004), *available at* <http://www.ead.anl.gov/pub/doc/ProducedWatersWP0401.pdf>.

²⁰⁵ Habel, *supra* note 120.

²⁰⁶ *Id.*

²⁰⁷ *Id.*

²⁰⁸ Veil, *supra* note 201.

²⁰⁹ For a brief description of the Underground Injection Control, or UIC, program, see Section I(B)(3).

²¹⁰ See <http://web.ead.anl.gov/pwmmis/index.cfm> for a summary of state regulations concerning produced water.

²¹¹ Eric Scott's paper, below, discusses the casing and cementing procedures for wells.

²¹² See Argonne National Laboratory, *Produced Water Management Information System: Federal and State Regulations*, <http://web.ead.anl.gov/pwmmis/regs/index.cfm#state> (last visited May 16, 2008).

²¹³ See Dep't of Toxic Substances Control, *California Hazardous Waste Classification: Introduction*, http://ccelearn.csus.edu/waste/class/intro/intro_01.html (last visited May 16, 2008).

questions.²¹⁴ First the state looks to see if the material is a waste or not.²¹⁵ Second, the state looks to see if the waste is exempted by any laws.²¹⁶

Next, the regulations impose a third tier of questions, that can have the affect of taking a waste out of the category of exempt waste and into the hazardous waste category, as a matter of state law.²¹⁷ If a waste exempt from RCRA exhibits one of four hazardous waste criteria: toxicity, ignitability, corrosivity, or reactivity, it is deemed hazardous.²¹⁸ If the E&P waste is determined to be corrosive, reactive or ignitable, then it is considered to be hazardous and no longer exempt.

For the fourth characteristic, toxicity, there are two tests; TCLP and WET. California's consideration of toxicity depends on which test the oil producer uses. The TCLP, or Toxicity Characteristic Leaching Procedure, is the RCRA-required test for toxicity of non-exempt waste and tests for the movement of organic and inorganic chemicals.²¹⁹ WET, the waste extraction test, tests for more chemicals than the TCLP test and is a more sensitive measure of the same chemicals that the TCLP test examines.²²⁰ Overall, the TCLP test is less sensitive than the WET.²²¹ If the producer uses the WET and it fails, then the state considers the waste toxic and therefore hazardous.²²² If the waste passes the less sensitive TCLP test then the state does not consider it toxic or hazardous.²²³ If the less sensitive test determines that the waste is toxic, it can be assumed that the more sensitive test would determine that as well for a smaller portion of the waste.²²⁴ The oil and gas industry wanted the TCLP procedure to be the determining test because of its lesser sensitivity and cheaper cost.²²⁵ However, the producer can use either method, but it only makes sense that they would use the less expensive, less sensitive and broader exempting TCLP test.²²⁶ This requirement on the operator takes a significant burden off of the state agencies as the state does not need to go out to every site to complete testing.

(ii) *Mixing exempt and non-exempt waste*

California also has a stricter rule on mixing waste than RCRA. RCRA states that if a producer mixes a hazardous waste with a non-hazardous waste, then the composite becomes hazardous.²²⁷ But if the producer mixes exempt with non-exempt wastes, then the producer has

²¹⁴ See *Id.*

²¹⁵ *Id.*

²¹⁶ *Id.*

²¹⁷ See Dep't of Toxic Substance Control, "California Hazardous Waste Classification: Hazardous Waste Categories," http://ccelearn.csus.edu/waste/class/mod7/mod7_01.html (last visited May 16, 2008).

²¹⁸ *Id.*

²¹⁹ Environment, Health and Safety Online, "The EPA TCLP," <http://www.ehso.com/cssepa/TCLP.htm> (last visited May 16, 2008).

²²⁰ Dep't of Toxic Substances Control, "California Hazardous Waste Classification: Hazardous Waste Categories," *supra* note 213.

²²¹ See Habel, *supra* note 120.

²²² *Id.*

²²³ *Id.*

²²⁴ *Id.*

²²⁵ *Id.*

²²⁶ *Id.*

²²⁷ U.S. EPA, *Exemption of Oil and Gas From Federal Regulations*, *supra* note 117.

to examine the toxicity of the entire mixed waste.²²⁸ RCRA itself would allow for the mixing of produced water with a non-exempt waste in order to dilute the toxicity of the non-exempt waste. In fact, produced water is often mixed with other wastes for disposal, and RCRA rules state that it may be mixed with any other exempt waste as well.

However, California rules state that producers can not mix a waste with anything else to dilute it or render it non-hazardous.²²⁹ All individual components must be tested before mixing or else the mixture will not be accorded the RCRA exemption, thus becoming a hazardous waste subject to full RCRA disposal rules.²³⁰ California's rule ensures that cleaner produced water may not be mixed with a hazardous waste to ease disposal requirements.

The last measure of protection ensuring that produced water remains as clean as possible covers the tanks that produced water sits in during the extraction of oil and gas. As noted earlier, chemicals, like BTEX, can settle to the bottom of tanks and then be reabsorbed by the produced water if the water sits too long or the tanks are not cleaned and maintained well enough. California requires that producers test tank bottom wastes depending on how often the tanks are cleaned out.²³¹ This requirement encourages producers to keep their tanks clean which in turn helps to ensure that produced water remains clean. If the producers don't regularly clean out their tanks they will be required to test their tank bottoms as well as their produced water.²³² This increased cost cuts into their profits, ensuring that it is in the producers' interest to regularly clean out the tanks, providing for cleaner produced water before it is ever injected into a well.

2. Regulation of Produced Water at the Time of Disposal: Louisiana and the UIC Program

Louisiana, like most states, is in charge of administering the Underground Injection Control (UIC) program within the state. Also, like most states, Louisiana has limited itself to implementing regulations in line with the requirements of the UIC program.

In order to protect drinking water sources, the goal of the UIC program, Louisiana requires that all operators seeking to drill a new well for disposal or to dispose of produced water in an already built well, must obtain a permit from the Louisiana Office of Conservation Geological Oil and Gas Division.²³³ The permit must show all existing wells and geological features surrounding the well.²³⁴ This includes mapping out any "[u]nderground source of drinking water" surrounding the well.²³⁵ The state requires that new wells are spaced far enough away from old wells to prevent any possible cross contamination between wells and therefore into underground drinking water supplies.²³⁶ Additionally, before produced water is disposed of

²²⁸ *Id.*

²²⁹ Dep't of Toxic Substances Control, "California Hazardous Waste Classification: Introduction," *supra* note 209.

²³⁰ *Id.*

²³¹ Habel, *supra* note 120.

²³² *Id.*

²³³ LA. ADMIN CODE tit. 43, § 403 (2005).

²³⁴ LA. ADMIN CODE tit. 43, § 405 (2005).

²³⁵ LA. ADMIN CODE tit. 43, § 403 (2005).

²³⁶ LA. ADMIN CODE tit. 43, § 405 (2005).

he produced water must be tested and any surrounding groundwater must be tested.²³⁷ The purpose of this testing is not for the same purposes as California.²³⁸ The testing of the groundwater is to determine whether the groundwater is already contaminated or not before disposing of the produced water.²³⁹ Louisiana carries the full RCRA E&P exemption; therefore, produced water is exempt from any hazardous waste standards. So testing of produced water is not to determine its hazardous nature before disposal, but rather to determine the total dissolved solids (TDS) which in turn helps the operator determine what pressure the produced water should be injected at.²⁴⁰

Louisiana takes extra steps in the requirements of the structure of the well, in order to make sure that what is injected down the well stays within the confines of the well. The applicant must identify the deepest source of underground drinking water and set the surface casing from below that source all the way to the surface. There are several other steps in casing and plugging a well that Louisiana requires applicants to go through to ensure containment, but these steps are too complex to go into here.²⁴¹ Additionally, Louisiana requires pressure tests on every well at least once every three years. These pressure tests will show whether the well is leaking because if the pressure is not staying constant then there is the chance that a leak has occurred.²⁴² State inspectors are on site for all testing as well. Louisiana's UIC program has eight inspectors to cover 3,000 wells across the state.²⁴³ Yet, they are still able to inspect and pressure test every well once every three years and most wells are even inspected once a year.²⁴⁴ In Louisiana, many of the wells are grouped geographically, so the inspectors have areas they cover. In some areas, one inspector can inspect ten wells in a day.²⁴⁵

3. UIC and RCRA: California and Louisiana

The UIC program measures explained above are steps that other states take in some form, including California. However, California's precautions over the actual content and safety of the produced water is an additional step protecting the state's groundwater resources. It is unclear whether this difference is because of California's reliance on groundwater, being a drier state than many others closer to the east coast or if there is some other unknown reasoning behind the added protection.

Also, the entire UIC program seems to be an afterthought to the RCRA exemption. After all, millions of barrels of produced water are injected underground every year, waste that is completely exempt from any national hazardous waste requirements. Without additional measures, the possibility of contamination of underground drinking water sources would appear more than likely. The UIC program seems to give some protection where there is none

²³⁷ *Id.*

²³⁸ Email from Laurence Bland, Director, Louisiana Injection and Mining Division of Office of Conservation (April 14, 2008).

²³⁹ *Id.*

²⁴⁰ *Id.*

²⁴¹ Eric Scott's paper on well abandonment spends more time with the procedure of casing in a well.

²⁴² Bland email, *supra* note 234.

²⁴³ *Id.*

²⁴⁴ *Id.*

²⁴⁵ *Id.*

otherwise, but without stepping on the toes of the RCRA E&P exemption: if E&P wastes were not exempt from RCRA, then the UIC program would regulate them more strictly.

CONCLUSION

The breadth of the E&P exemption in RCRA gives states wide leeway to regulate E&P waste as they deem necessary. States may form regulations aimed at controlling steps in the E&P processes, types of waste, degree and type of contamination, the effect on natural resources and public health, or even the method of disposal. The methods of regulation covered here represent only a fraction of the existing methods used by oil producing states. Even though many states have adopted the exemption, several have taken other measures to protect natural resources and public health. Overall states are making an attempt to gather more information about the E&P process—i.e. the location of pits and the toxicity of produced water—information that has led to more regulation in some states, and may lead to more effective regulation in the future.

INTRODUCTION

This survey provides an overview of drilling and casing requirements imposed on operators drilling an oil or gas well: pressure testing of cement and casing strings are a particular. The primary purpose of casing regulations is to protect groundwater from contamination by oil and gas. Additionally, casing guidelines also serve to protect mineral deposits from being contaminated by oil, gas or water. For example, Wyoming provides for the protection of sodium deposits,²⁴⁶ and Utah protects areas rich in potash.²⁴⁷ Early regulations of oil and gas wells, however, were primarily concerned with preventing waste of oil and gas, as opposed to protecting the environment from oil and gas contamination.²⁴⁸

This survey seeks to provide the reader with a guide to oil and gas casing laws around the nation. It provides the statutory and regulatory locations of the relevant sections for pursuing further research.

I. FEDERAL STATUTES REGARDING DRILLING AND CASING

As mentioned above, the primary purpose of drilling and casing regulations is to protect groundwater by preventing seepage of oil and gas into water bearing strata while the primary purpose of the Clean Water Act is to regulate the discharge of water and pollutants into the waters of the United States.²⁴⁹ Importantly, the CWA only regulates surface waters; thus, it does not affect state regulation of drilling practices because these relate to subsurface water. Additionally, the federal exemptions that the oil and gas industry received in the CWA do not apply to the issues covered in this survey.

Two primary exemptions in the CWA affect the oil and gas industry. The first is definitional. Under CWA §502(6)(B) pollution does not mean:

water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil or gas production and disposed of in a well, if the well used either to facilitate production or for disposal purpose is approved by authority of the State in which the well is located, and if such State determines that such injection or disposal will not result in the degradation of ground or surface water resources.

²⁴⁶ WYOMING ADMIN. CODE Oil Gen Ch. 3 § 22(d)-(g).

²⁴⁷ UTAH ADMIN. CODE § R649-3-28. Potash is a type of potassium commonly used in fertilizers.

²⁴⁸ See Barron W. Dowling, *White Oil and Greenback Dollars: An Overview of Controversies Surrounding Production of Gas From the Panhandle Field of Texas*, 19 St. Mary's L. J. 81, at 86 (1987) (“[T]he State of Texas has attempted to regulate wasteful gas production since 1899 when House Bill 542 required oil and gas operators to use surface casing to prevent fresh water from ‘penetrating the oil and gas bearing bedrock.’”).

²⁴⁹ 33 U.S.C. §1251.

This definition therefore excludes water pumped into the ground, but not surface runoff. The issue of injection may be exempted from the CWA; however, it is covered by the EPA's Underground Injection Program implemented through the Safe Drinking Water Act.²⁵⁰ While injection of fluids is a major issue with protection of groundwater supplies in oil drilling it is not the subject of this survey.

Additionally, Section 402 of the CWA, entitled "Pollution Discharge Elimination System" excludes storm runoff from oil and gas facilities if it does not come into contact with any other contaminated material. Because this relates to surface waters, it does not interfere with any regulation covered in this survey. Furthermore, the EPA states that "this final rule is not intended to interfere with the ability of States, Tribes, or local governments to regulate any discharges through a non-NPDES permit program."²⁵¹ Thus, the rule is not a concern of this survey.

II. TECHNICAL BACKGROUND

The basic underground structure of a well frequently consists of the following components: surface casing, intermediate casing, production casing, and tubing.

According to the Texas National Resource Conservation Commission, "surface casing is pipe that is used in conjunction with cement to protect groundwater and to keep the well from caving in and blowing out."²⁵² Furthermore, the purpose of the casing is to prevent "fluids—which could contain salt, hydrocarbons, or other harmful materials—from migrating into usable groundwater aquifers."²⁵³ In the context of drilling and construction, "surface casing is the first casing put in a well that is cemented into place. . . . It also acts as a foundation or anchor for all subsequent drilling activity."²⁵⁴

Next, a well operator puts into place intermediate casing. Intermediate casing is not always required or necessary when drilling a well. The State of Indiana defines an intermediate string of casing as a "length of pipe set below the surface casing string, but before the production casing is run, to isolate one or more zones."²⁵⁵ According to the National Geoscience Database of Iran, the purpose of intermediate casing is to minimize the effects of various subsurface conditions.²⁵⁶ Such effects include "abnormal underground pressure zones, underground shales, and formations that might otherwise contaminated the well, such as underground salt-water deposits."²⁵⁷ Thus, intermediate casing is intended as a precautionary measure when drilling oil

²⁵⁰ See 42 U.S.C. § 300f.

²⁵¹ 71 FED. REG. 33635.

²⁵² See Texas Commission on Environmental Quality, "Don't Drill Without it! Get a surface casing letter from the TNRCC," *available at* http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/rg/rg-385.html (last visited Dec. 3, 2008).

²⁵³ *Id.*

²⁵⁴ KANSAS ADMIN. CODE 82-3-106(a)(74).

²⁵⁵ 312 INDIANA ADMIN. CODE § 16-1-31.2.

²⁵⁶ National Geoscience Database of Iran, "Extraction,"

<http://www.ngdir.ir/geolab/GeoLabExp.asp?PEXPCode=2890&PID=857> (last visited Dec. 3, 2008).

²⁵⁷ *Id.*

wells, providing protection against caving of weak subsurface formations.²⁵⁸ This purpose manifests itself in the regulatory structures of many states, requiring that intermediate casing be employed when subsurface conditions are unknown.

Production casing is the final casing installed in the well and is the deepest and narrowest of the casing strings.²⁵⁹ Tubing will be placed within the production casing for the extraction of oil. Tubing is defined as “a string of pipe set within a cased well through which fluid is produced or injected.”²⁶⁰ According to OSHA, oil is more easily extracted through the smaller diameter of tubing than through the production casing.²⁶¹

After every casing string is set it must be cemented in place. Most regulatory schemes require the surface casing to be cemented from the annulus to the surface. The annulus is “the space between the well bore wall and a string of casing, two strings of casing, or the tubing and the innermost casing.”²⁶² Most states require that cementing be accomplished either through the “pump and plug” or the displacement method.²⁶³

III. A BRIEF COMPARISON OF STATES’ DRILLING AND CASING REGULATIONS

Texas best exemplifies a proactive and cohesive approach to protecting groundwater supplies through its casing and drilling regulations, in terms of the providing information to operators and describing casing operations in nuanced detail. No doubt, this is due to the importance of the oil industry in the state. What distinguishes Texas’s approach from others are the multiple safeguards at various points in the production process and the proactive efforts of the regulatory body.

Before constructing a casing, the operator must obtain a letter from the Texas Commission on Environmental Quality that sets forth the depth the well must reach.²⁶⁴ The Texas National Resource Commission proactively seeks to educate oil and gas operators about the need to obtain this letter. The publication “*Don’t Drill Your Oil Well Without It!*” provides a succinct guide to the basic regulatory requirements that an operator must meet. It includes information on how to obtain a letter, who needs to obtain one, what information must be provided, and how long the process takes. Additionally, the agency’s “surface casing team” maintains geographic maps of the various regions of Texas along with the location of existing oil and gas wells. A map of the region is provided to a prospective oil or gas operator, which includes geographic contours as well as the depth and location of protected groundwater. These

²⁵⁸ *Schlumberger Oilfield Glossary*, *supra* note 12,

<http://www.glossary.oilfield.slb.com/Display.cfm?Term=intermediate%20casing>.

²⁵⁹ *See id.*, <http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=307>.

²⁶⁰ 312 INDIANA ADMIN. CODE § 16-1-47.

²⁶¹ OSHA, “Oil and Gas Well Drilling and Servicing eTool,”

http://www.osha.gov/SLTC/etools/oilandgas/well_completion/well_completion.html#Set%20Production%20Casing (last visited Dec. 3, 2008).

²⁶² 312 INDIANA ADMIN. CODE § 16-1-4.

²⁶³ *See, e.g.*, 6 NEW YORK CODES R. & REGS. § 554.4(b) and (d) (“it shall be cemented by the pump and plug or displacement method with sufficient cement to circulate to the top of the hole”); contrast with Texas which requires the “pump and plug” method for surface casings: 16 TEXAS ADMIN. CODE § 3.13.

²⁶⁴ 16 TEXAS ADMIN. CODE § 3.13.

maps indicate the depth to which the surface casing must be set. The value of this approach is that it is proactive, and it makes a complex regulatory regime comprehensible to those who are affected by its requirements.

There are three more safeguards in Texas's regulatory approach. The first is the requirement that steel used in casing must be hydrostatically tested prior to its use.²⁶⁵ Presumably, this occurs at the manufacturing stage. Second, the operator must pressure test surface casing strings that are longer than 200 feet.²⁶⁶ Finally, after the surface casing is cemented, the operator must pressure test the zone of critical cement before the plug is drilled.²⁶⁷ The zone of critical cement is defined as the bottom 20% of the casing string.²⁶⁸ This is different from other regulatory approaches, which typically require pressure testing of the casing string only. A few jurisdictions only require pressure testing of the cementing and not the casing. Texas, on the other hand, requires testing of both. The primary negative aspect to Texas's regulatory structure is the lack of clarity as to who has authority over what issue. Officially, the Railroad Commission has authority over oil and gas issues, but the Texas Commission on Environmental Quality is in fact the regulator.

Colorado's approach is typical of the status quo. First, the surface casing depth varies depending on knowledge (or lack thereof) of subsurface conditions.²⁶⁹ This is a distinction commonly found in many states' regulations. In contrast, this distinction is not made by the Texas regulations, since the letter from the TCEQ provides the relevant subsurface information to the oil or gas operator.

Additionally, Colorado requires oil and gas operators to cement surface casing to the surface, which is almost a universal requirement among states.²⁷⁰ The cement must then be allowed to set for 12 hours and then pressure tested to reach a compressive strength of 300 pounds per square inch (psi) after 24 hours and 800psi after 72 hours.²⁷¹ There are two basic approaches to compressive strength requirements among status quo states. Many require testing to an exact strength, which measures between 300psi and 1,200psi, with most clustered at the more highly pressurized end of the spectrum. Other states require a compressive strength that is calculated by multiplying the length of the casing string times. Finally, Colorado requires intermediate and production strings to be cemented and tested to a lesser compressive strength.²⁷²

The state with the most disappointingly sparse regulation is New York. According to the Department of Environmental Conservation's website, the Division of Mineral Resources database includes over 33,000 wells and 2,500 subsurface mines²⁷³. Despite this fact, the regulations provide very little guidance for the construction of well casing. The only substantive

²⁶⁵ 16 TEXAS ADMIN. CODE § 3.13.

²⁶⁶ *Id.*

²⁶⁷ *Id.*

²⁶⁸ *Id.*

²⁶⁹ 2 CCR 404-1 (317 Drilling Rules).

²⁷⁰ *Id.*

²⁷¹ *Id.*

²⁷² *Id.*

²⁷³ New York Dep't of Environmental Conservation, "Geographic Information on New York's Wells and Mines," <http://www.dec.ny.gov/energy/4733.html> (last visited Dec. 3, 2008).

requirements are that the operator set the surface casing below freshwater levels and cement the casing to the surface.²⁷⁴ The regulatory regime is silent on the use of intermediate or production casing, and requires no pressure testing or cement setting times. For environmental protection, the statute instructs operators to prevent the pollution of water.²⁷⁵ Thus, New York's casing and drilling requirement is well outside the norm. South Dakota is another sparse regulatory regime.²⁷⁶ However, it is important to note that the state only had 153 active wells in 2007, and a peak of 213 wells in 1993.²⁷⁷

CONCLUSION

This survey is intended to provide a brief guide to a narrow, but important topic for drilling oil and gas wells. It is not intended to provide a comprehensive analysis of every state's regulatory regime. Due to resource constraints, this edition does not discuss the regulations of Alabama, Alaska, California, Louisiana, Ohio, Pennsylvania and West Virginia; in particular, the regimes of Pennsylvania and California are notable and regrettable omissions.

²⁷⁴ 6 NEW YORK CODES R. & REGS. § 554.1, 554.4.

²⁷⁵ 6 NEW YORK CODES R. & REGS. § 554.1(b).

²⁷⁶ See S.D. ADMIN. R. §§ 74:10:03:14, 74:10:03:16

²⁷⁷ *Historic South Dakota Oil Production (1954-2007)*, available at <http://www.state.sd.us/denr/DES/Mining/Oil&Gas/Documents/PROD-OIL.pdf> (last visited Dec. 3, 2008).

The following table is a rough guide to pressure testing and cement setting times. It does not capture the nuances of the various regulations. Some states require cement to set for a period of time before any pressure testing is conducted, while others require the cement to set before the plug is drilled. Still others require pressure testing, and the cement setting time is implied in the regulation, since the test must occur for a period of 8 hours, or two pressure tests must be conducted on different days. Additionally, the strengths and times required vary. Finally, drilling with cable tools is not included in this table.

	Pressure Testing	Cement setting times
Arizona	Yes	Yes
Arkansas	No	Yes
California		
Colorado	Yes	Yes
Florida	Yes	Yes
Georgia	No-surface/ yes production	Yes-surface
Indiana	Yes (no specified strength)	Yes
Illinois	No	Yes (but below average w/ exceptions)
Indiana	No (but required at abandonment)	No
Kansas	Yes (below average)	Yes
Kentucky	No	No
Maryland	Yes (no specified strength)	Yes
Missouri	Yes	Yes
Mississippi	Yes	Yes
Montana	Yes	Yes
Nebraska	Yes	No

Nevada	Yes	No
New Mexico	Yes	Yes
New York	No	No
North Carolina	Yes	Yes
North Dakota	Yes	Yes
Oregon	Yes	Yes
Pennsylvania	Yes	Yes
South Dakota	No	No
Tennessee	No	No
Texas	Yes	Yes
Utah	Yes	No
Virginia	Yes	Yes
Washington	Yes	No
Wyoming	Yes	No

ARIZONA

Agency: Arizona Geological Survey

Statute: Title 27, Ch. 4 Minerals, Oil and Gas

Regulation: Arizona Administrative Code Title 12, Natural Resources

Summary of relevant provisions:

R12-7-110 Surface Casing Requirements

- The Commission must be notified before setting the surface casing so representative may witness all or part of the operations
- Surface casing must be set at a sufficient depth to protect an isolate freshwater zones and to protect blowouts or uncontrolled flows
- Big enough to allow intermediate strings of casing
- Cemented by the pump and plug method
- Cemented to the surface and allowed to set for 12 hours prior to drilling
- Pressure testing: “30 minutes to 70% of internal yield pressure or one psi per foot of casing depth, whichever is less.” During the test the pressure cannot drop by more than 10%.

R12-7-111 Intermediate and Production Casing

- All wells must have production casing
- The Commission has the power to order additional strings of intermediate casing
- Intermediate and production casing must meet the same pressure testing requirements as surface casing

Other regulations of interest

- R12-7-112: Defective Casing or Cementing

ARKANSAS

Agency: Oil and Gas Commission

Statute: Title 15, subtitle 6 Natural Resources and Economic Development

Regulation: Oil and Gas Commission Rules and Regulations

available at <http://www.aogc.state.ar.us/OnlineData/Forms/Rules%20and%20Regulations.pdf>

Summary of relevant provisions:

Rule B-15 Casing Requirements

- All freshwater sands must be protected by setting surface casing
- Surface casing shall be cemented to the surface by the pump and plug method
- Cement must set for 12 hours before drilling
- Subsection b governs wildcat wells. The amount of casing depends on the depth of the well and in what county the well is located.
- A string of productive casing must be set to at least the top of the production formation and shall be cemented to at least 250 feet above the productive interval. The cement must be by the pump and plug method and allowed to set for 24 hours

Rule B-29 Casing Tests

- Repealed October 15, 2006

COLORADO

Agency: Oil and Gas Conservation Commission

Statute: Title 34, art. 60 Oil and Natural Gas

Regulation: 400 Department of Natural Resources 2 CCR 404-1

Summary of relevant provisions:

317 Drilling rules

- Surface casing requirements when subsurface conditions are unknown (depth)
 - Must be set at a depth below all utilizable domestic freshwater
 - Must be big enough to allow for intermediate strings of casing
 - Cemented by pump and plug method to the surface
- Surface casing requirements when subsurface conditions are known (depth)
 - Must be set at a depth sufficient to protect groundwater
 - Cemented by pump and plug method to the surface
- Testing and cementing for surface and intermediate casing cementing
 - Must test for a minimum compressive strength of 300psi after 24 hours, and for 800psi after 72 hours measured at 92 degrees Fahrenheit.
 - Intermediate casing:
 - Cemented to a depth at least 200 feet above the top of the shallowest known production horizon
 - Must set for 8 hours or until it has reached a compressive strength of 300psi
- Testing and cementing for production casing
 - Pressure requirements are the same
 - Cementing (applies if the well is by an aquifer)
 - All fresh water aquifers below the surface casing must be cemented behind the production casing
 - Cementing must be set 50 ft. below the bottom of the fresh water aquifer and run to at least 50 ft. above the aquifer
- Suspension of drilling-applies if drilling has ceased before the production casing is set
 - Must immediately notify the director
 - Must take all precautions to protect oil from seeping into water or vice versa

FLORIDA

Agency: Department of Environmental Protection, Geological Survey

Statute: Chapter 377 Natural Resources

Regulation: Title 62, Subtitle 62C-27 Conservation of Oil and Gas

Summary of relevant provisions:

62C-26.003 Drilling Applications

- Drill application must include a casing and cementing program with the following:
 - Setting depths and casing size
 - Grade of pipe used with its specified minimal yield strength
 - Any use of cement additives and the class and quantity of cement used
 - Weight per/ft. of the casing plus the wall thickness
 - What type of method used (i.e displacement or pump and plug)

62C-27.005 Casing

- Surface casing must be set below the deepest utilizable water source and cemented to the surface
- Surface casing must be set at the following minimum depths without reference to water sources

Well Depth	Surface Casing
0 -- 7,000	1,500
7,000 -- 9,000	1,750
9,000 -- 11,000	2,250
11,000 -- 13,000	3,000
13,000 -- Below	3,500

- Intermediate casing must be set according to generally accepted industry standards
- Production/injection casing must be set according to generally accepted industry standards and cemented to at least 1500 ft. above the uppermost producible hydrocarbon zone
- Pressure testing and cement wait periods
 - If a float valve is used cement must set for 12 hours, or 24 if one is not used
 - The following strings must meet the minimum surface test pressure
 - Surface 1,000psi
 - Intermediate 1,500psi
 - Liner 1,500psi
 - Production 1,500psi
 - Tubing 1,00psi

GEORGIA

Agency: Georgia Department of Natural Resources

Statute: Title 12, Ch. 4 Conservation and Natural Resources

Regulation: Title 391, subtitle 3, ch. 13 Oil and Gas and Deep Drilling

Summary of relevant regulations:

391-3-13-.10 Drilling

- Must notify the director 24 hours in advance of setting casing or plugging
- Controlling the well
 - Casing and cementing program must take into account depths penetrated, pressures expected to be encountered, and must confine freshwater to its strata (see 3-13.04, must include program in application)
- Surface Casing
 - Sufficient level of strings of high quality casing to prevent leaks, contamination of freshwater etc.
 - Surface casing must use new or reconditioned pipe
 - Cemented with a volume sufficient to fill from shoe to the surface +10%
 - Must set for 12 hours before the cement plug is drilled
- Production casing
 - Shall be cemented to at least 500 ft. above the uppermost producible hydrocarbon zone
 - Shall be tested at a pressure of 0.2 pounds per square inch per foot of casing or a maximum test of 1500 pounds per square inch. Cannot drop more than 10% in 30 minutes

IDAHO

Agency: Idaho Department of Lands

Statute: Title 47, Ch.3 Mines and Mining, Oil and Gas Wells

Regulation: Agency 20 Idaho Department of Lands, Title 7, Ch.2 Conservation of Oil and Natural Gas in the State of Idaho

Summary of relevant regulations:

20.07.02.080 General Drilling Wells

- Surface casing when subsurface conditions are unknown
 - Casing set at depth below all known levels of utilizable sources of domestic freshwater
 - Must be big for intermediate casing strings if needed
 - Casing must be set in or through an impervious formation and cemented by pump and plug or displacement method and cemented to the top of the hole
- Surface casing when subsurface conditions known
 - Set at depth sufficient to protect utilizable domestic freshwater
- Cement must set for 8 hours under pressure before drilling the plug
 - Under pressure: “1 float valve is used or pressure is otherwise held”
- Production string: must be cemented and pressure tested, but no specifics are listed (presumably the same as “under pressure” above)
 - Production string is not required
- There is a duty to report any encounter with freshwater sands to the Commission

ILLINOIS

Agency: Department of Natural Resources, Oil and Gas Division

Statute: Ch. 225 (Professions and Occupations) Act 725, Illinois Oil and Gas Act

Regulation: Title 62 (Mining), ch.1, part 240 The Illinois Oil and Gas Act

Summary of relevant regulations: (located under subpart F)

240.610 Construction Requirements for Production Wells

- Surface casing requirements (if drilled after 5/13/94)
 - Must use steel surface casing or fiberglass casing meeting API standards
 - Must submit and get approval of casing plan or have a department representative present during the drilling
 - Cemented from depth to surface and allowed to set for at least 4 hours or until it reaches a sufficient strength to allow drilling to resume
- Production casing requirements (if drilled after 5/13/94)
 - Must be cemented from the depth of the casing to at least 250 feet above the shallowest producing interval
 - If prior to 1994: if no surface casing was set, must be set and cemented to the surface, If surface casing than requirement is the same
- Alternative casing procedures (cannot be over a coal mined out area or natural gas field)
 - Must notify the Director of intent to use alternative procedure (24hrs.)
 - If the unconsolidated material is less than 25 feet thick no surface casing is required
 - Instead a cement basket may be set 50 ft. below the base of fresh water in the zone and the production casing shall be cemented from the basket to the surface
 - If the unconsolidated material is more than 25 feet thick
 - Surface casing is required (same as normal requirements above) and production casing must be set and cemented from 50 feet below water table, or total depth of the well to the surface
 - Wells that are 500 feet below the base of freshwater
 - No surface casing or cement basket is required and production casing must be cemented from the total depth to the surface

INDIANA

Agency: Department of Natural Resources, Oil and Gas Division

Statute: Title 14 (Natural and Cultural Resources) Art. 37 Oil and Gas

Regulation: Title 312 (Natural Resources Commission) Art. 16 Oil and Gas

Summary of relevant regulations:

312 IAC 16-5-9 Well Construction

- Casing, tubing and drill pipe shall be run and set in conformance with API specifications
- Surface casing
 - “Run below the lowest underground source of domestic water”
 - Shall be set in or through an impervious formation and cemented to the top of the hole
 - Shall use intermediate strings of casing if necessary to protect ground water
 - Alternative approach to above requirements: may cement an intermediate or long string of casing to the top of the hole
- Production casing
 - If the well is not abandoned after the completion of drilling the production casing must be immediately installed
 - It shall be set at the bottom of the hole or at the top of the last stratum drilled
- Regulation does not require pressure testing or cement setting times

Other regulations of interest:

- 312 IAC 16-5-20: Temporary abandonment of wells does require periodic pressure testing

KANSAS

Agency: Corporation Commission, Oil and Gas Conservation Division

Statute: Chapter 55 Oil and Gas

Regulation: Agency 82, art. 3 Production and Conservation of Oil and Gas

Summary or relevant regulations:

82-3-103 Notice of Intention to Drill

- Notice must contain the estimated depth of the well and the depth to the bottom of the deepest freshwater at the drill site
- The approval to drill notice from the conservation division shall include surface and casing requirements

82-3-105

- Cement must be used for the setting of casing and sealing off of production, freshwater or storage formations

82-3-106 Cementing-In Surface Casing

- A minimum depth of 50ft. of steel surface casing is required, but the commission may require more or less to protect groundwater
- Two ways to protect water
 - First: Cement the casing from the base to the surface and cannot drill to any depth to test for oil or gas without first setting and cementing a continuous string of surface casing
 - Second: First string of casing set through all unconsolidated material and 20ft. into the underlying formation; surface casing cemented to the surface; additional casing next to the borehole shall be cemented from at least 50ft. below the base of the lowest known fresh and usable water; and must notify the commission prior to the cementing of any additional casing
- Testing for cemented casing string
 - Must stand for 8 hours under a compressive strength of 300psi unless the commission modifies the requirement

KENTUCKY

Agency: Department of Natural Resources, Oil and Gas Division

Statute: Ch. 53 Mines and Minerals

Regulation: Title 805 (Public Protection and Regulation Cabinet Department of Mines and Minerals), Ch. 1 Division of Oil and Gas

Summary or relevant regulations:

805 KAR 1:020 Protection of freshwater zones

- Three possible methods for protecting freshwater zones when drilling or plugging
 - First: Casing set on casing shoulder, shoe installed on the bottom of the bottom joint; upon completion of drilling all recoverable casing must be removed or cemented to the surface
 - Second: Casing set on a shoulder; cemented sufficiently to cover 100ft including the shoe, upon completion of drilling all recoverable casing must be removed or cemented to the surface
 - Third: Use a top to bottom mud system with a filtrate water loss of less than 10 cubic centimeters as determined by API standards in 1990
- Casing requirements: must have the following prior to production or injection
 - A protective string of casing (surface, intermediate or long string) that is 30ft. below the deepest known freshwater zone, and is cemented to the surface
 - If abnormal subsurface pressures are encountered or expected the surface or intermediate casing must be anchored with sufficient cement and depth to contain pressures
- There are no pressure testing or cement setting requirements

MARYLAND

Agency: Department of Environment, Mining Program

Statute: Environment Title 14 Gas and Oil

Regulation: Title 26 (Dept. of Env.) Subtitle 19, Oil and Gas Exploration and Production

Summary of relevant regulations:

26.19.01.10 Drilling and Operating Requirements

- When actual drilling begins the driller shall permanently set a string of surface casing to a depth of at least 100ft. below the deepest known strata bearing freshwater or the deepest known coal seam (whichever is deeper)
- Surface casing: cementing and testing
 - Shall be cemented to the surface and allowed to set at a static balance or under pressure for a minimum of 12hrs. before drilling the plug
- Other strings of casing: depth, cementing and testing
 - Sufficient type and weight for the depth and pressure expected
 - Enough cement to provide for an effective seal above any producing zone
 - Must be properly pressure tested and allowed to set for 4 hours
- Must report to the department
 - Depth at which any freshwater inflow was encountered
 - Total depth of the well
 - Amount of cement used for each casing string

MICHIGAN

Agency: Department of Environmental Quality, Office of Geological Survey

Statute: Chapter 319 Oil, Gas and Minerals

Regulation: Dpt. of Env. Quality (R324.101 through 324.1301) Oil and Gas Operations

Summary of relevant regulations:

R 324.408 Surface Casing

- Must be set 100ft. below the base of the glacial drift into competent bedrock and 100ft. below any freshwater strata, and cemented to the surface

R 324.411 Cementing

- Must be cemented by the pump and plug method
- Cement must set for at least 12 hours undisturbed as a static balance with the casing in tension with no backflow until the tail-in slurry must reach 500psi compressive strength

Other regulations of interest

- 324.409: Special rules for wells drilled with cable tools
- 324.410: Rules for other types of casing if the department requires it

MISSISSIPPI

Agency: Oil and Gas Board

Statute: Title 53 Oil, Gas and other Minerals

Regulation: Order No. 201-51

Summary of relevant regulations:

Rule 11 Surface Casing

- Proposed casing program must be included in application to drill
- Length of the casing depends on the depth of the well. A depth of 0-2500 ft. requires 200 ft. of casing with a well that is 9,000 ft. below the surface requires casing of 930 ft. + 25% of the proposed depth in excess of 9,000 ft.
- Shall be cemented with the lesser of 500 sacks of cement or cement-admix or to the surface
- Pressure tests: 1 pound per square inch (1lb./sq. inch) for each foot of casing to a maximum of 1,000psi and the cement must stand for at least 12 hours

Rule 12 Production Casing

- Production casing is required and must be cemented to at least 500 ft. above the shoe
- Pressure tests: Length of production string times .2 (ft. of sting x .2 = psi) to a maximum of 1,500 psi and the cement must stand for 24 hours

MISSOURI

Agency: Department of Natural Resources

Statute: Title XVI (Conservation, Resources and Development) Ch. 259 Oil and Gas Production

Regulation: Title 10 (Dept. of Nat. Res.) Division 50 Oil and Gas Council

Summary of relevant regulations:

10 CSR 50-2.040 Drilling and Completion

- The surface casing must be set at the depth indicated on the application form, and cemented from this depth to the surface
- Before the bottom plug is drilled the cement must stand for:
 - 24 hours for neat cement
 - 12 hours for neat cement with one percent (1%) CaCl₂
 - 10 hours for neat cement with two percent (2%) CaCl₂
 - 8 hours for neat cement with three percent (3%) CaCl₂
 - 6 hours for neat cement with four percent (4%) CaCl₂
- All wells shall be cemented with string(s) of casing cemented at a depth sufficient to protect ground water
- If drilled with cable tools, temporary protective casing strings may be left uncemented
- Pressure testing is not required

MONTANA

Agency: Board of Oil and Gas Conservation

Statute: Title 82 (Minerals, Oil and Gas) Ch.11 Oil and Gas Conservation

Regulation: Title 36 (Dept. of Nat. Resources and Cons.) Ch.22 Oil and Gas Cons.

Summary of relevant regulations:

36.22.1001 Rotary Drilling Procedure

- Surface casing must be set below freshwater level and cemented to the surface by the pump and plug method
- If a production string is necessary it shall be set by the pump and plug method and properly pressure tested before drilling
- All casing strings must stand under pressure until the cement has reached a compressive strength of 300psi.
- Before conducting the pressure test the cement must set for 8 hours

36.22.1002 Cable Drilling Procedure

- Must have sufficient casing to protect ground water
- The casing must be tested by bailing to ensure a shutoff before drilling below the casing point

NEBRASKA

Agency: Oil and Gas Conservation Commission

Statute: Ch. 57 (Minerals, Oil and Gas) art. 9 Oil and Gas Cons.

Regulation: Title 267 Nebraska Oil and Gas Commission

Summary of relevant regulations:

Ch.3 012.01

- The conductor string of casing must be cemented throughout its length

Ch.3 012.02 Pressure and Formations Unknown

- Must have sufficient casing below the base of formations generally contributing to water supplies
- Casing must be big enough to allow for intermediate strings of casing
- Casing must be cemented to top of the hole

Ch.3 012.03 Sub-surface conditions known through drilling experience

- Casing must be set and cemented to the surface at a depth sufficient to protect water supplies

Ch.3 012.04

- Casing must be tested at a compressive strength of 500psi before drilling the plug
- The production string shall be cemented by the pump and plug method
- No set time for the cement is listed

NEVADA

Agency: Nevada Division of Minerals

Statute: Chapter 52 Oil and Gas

Regulation: Chapter 522 Oil and Gas

Summary of relevant regulations:

NAC 522.265 Wells Drilled With Rotary Tools

- Casing must be at a sufficient depth to afford safe control of any pressures encountered
- Surface casing must be set in an impervious formation and cemented to the surface
- All strings below the surface pipe must be cemented from the annular space behind the casing to at least 500 ft. above the bottom of the casing.
- A compressive strength of 300psi must be achieved before drilling

NAC 522.270 Wells Drilled With Cable Tools

- Surface casing set in the same manner as 522.265
- Casing must be tested by baling or pressure test to ensure a shutoff before drilling proceeds below the casing point

NEW MEXICO

Agency: Energy, Minerals and Natural Resources Department

Statute: Chapter 70 Oil and Gas

Regulation: Title 19 (Nat. Res. and Wildlife) Ch.15 Oil and Gas

Summary of relevant regulations:

19.15.3.106 Sealing off Strata

- Water strata above the producing and/or injection horizon shall be sealed or separated in order to prevent their contents from passing into other strata
- All freshwater must be confined to its strata and all water shall be shutoff with casing

19.15.3.107 Casing and Tubing Requirements

- Must have sufficient surface and production casing to isolate all water
- Casing must be cemented to the top of the hole
- Casing string must be cemented and allowed to set for 18 hours before conducting pressure test, or in some counties must set for 8 hours with a compressive strength of 500psi in the “zone of interest”
- Testing of casing strings
 - Rotary tools: ranges from 600psi-1500psi (approximately 1/3 of manufacturers yield pressure)
 - Cable tools: tested by the same method as rotary tools or by the bailing method

NEW YORK

Agency: Department of Environmental Conservation, Division of Mineral Resources

Statute: Chapter 43-B (Env. Cons. Law) art. 23 Mineral Resources

Regulation: Title 6 (Dept. of Env. Cons.) Ch.5 Resource Management Services

Summary of relevant regulations:

554.1 Prevention of Pollution and Migration

- “Drilling and casing program shall prevent pollution”
- Surface casing shall run below the deepest potable freshwater level
- Drilling and casing must prevent oil and gas from migrating to other stratum or pools

554.3 Cable Tool Drilling Practices

- Surface casing tested by the bailing method

554.4 Rotary Tool Drilling Practices

- If pressures are known must comply with the standards of 554.1(b), which essentially instructs the driller to not pollute, or to cement the production casing from below the deepest known potable fresh water level to the surface. When surface casing is used it shall be cemented to the surface.
- If pressures are unknown must cement the casing must follow 554.1(b)

New York does not require cement setting times or pressure testing

NORTH CAROLINA

Agency: Department of Environment and Natural Resources

Statute: Chapter 13 (Cons. and Development) subchapter V Oil and Gas

Regulation: Title 15A (Dept. of Env. And Nat. Res.) Ch. 5 Mining: Mineral Resources

Summary of relevant regulations:

5d.0007 Drilling and Completion

- All freshwater strata must be protected
- The casing shall extend to at least 50ft. below freshwater strata. It shall be cemented from the annular space behind the casing to the surface.
- If production string of casing is used it must be cemented to at least 500ft. above the casing shoe and at least 50ft. above the producible reservoir nearest to the surface
- Production must set for 24 hours before the plug is drilled and be tested by one of the following:
 - Pressure test: Reach a compress strength that equals length of the casing in feet times .2 (length ft. x .2 =psi). PSI is not to exceed 1,500.
 - Bailer test: must use fluid to fill to the midpoint (midpoint between casing base to top of the cement column). The fluid level cannot change by 2% in either direction for a period of 12 hours.

NORTH DAKOTA

Agency: Industrial commission, Department of Mineral Resources

Statute: Title 38, Ch. 38 Mining, Gas and Oil Production

Regulation: Title 43 (Industrial Commission) art. 43-02 Mineral Exploration and Development

Summary of relevant regulations:

43-02-03-20 Sealing off Strata

- All freshwater of probable value must be confined to its strata

43-02-03-21 Casing, Tubing, and Cementing Requirements

- Surface casing must reach a depth at least 50ft. below the Fox Hills formation and be cemented from the annular space behind the casing to the surface
- All strings of surface casing shall stand cemented under pressure for at least twelve hours before drilling the plug or initiating tests.
- Testing of surface casing: must stand under pressure until the tail cement has reached a compressive strength of 500psi
 - All filler cements utilized must reach a compressive strength of 250psi within 24 hours and 350psi within 72 hours
 - All tests for surface casing calculated at a temperature of 80 degrees Fahrenheit
- Production and intermediate casing
 - Shall be composed of pipe that has been previously tested to a strength of 2,000psi
 - Must stand under pressure until the tail cement reaches a compressive strength of 500psi.
 - All filler cement must reach a compressive strength of 200psi in 24 hours and 500psi within 72 hours
 - After the production or intermediate casing has been cemented it must be tested by application of pump pressure of 1,500psi. It must not drop by 150psi in a 30 minute period
 - Note that this section has very specific and unique temperature testing requirements

OKLAHOMA

Agency: Corporation Commission, Oil and Gas Conservation Division

Statute: Title 50 Oil and Gas

Regulation: Title 165 (Corporation Commission) Ch. 10 Oil and Gas

Summary of relevant regulations:

165:10-3-4 Casing, Cementing, Wellhead Equipment, and Cementing Reports

- Surface Casing: Must be set to a minimum depth of 90ft. below the surface or 50ft. below the base of treatable water (whichever is more). The surface casing must be set and cemented before the operator drills 250ft. below the base of treatable water. The surface casing must be cemented back to the surface and allowed to set for 8 hours. It is possible to use alternative casing and cementing procedures with departmental approval.
- Pressure testing of casing strings: Must test to a compressive strength that equals .2 times the length of the casing (.2 x ft. =psi) up to 1,500psi. The pressure cannot drop more than 10% in 30 minutes.

OREGON

Agency: Department of Geology and Mineral Industries

Statute: Title 43 (Mineral Resources) Ch.52 Conservation of Gas and Oil

Regulation: Chapter 632 (Dept. of Geology and Min. Ind.) Division 10 Oil and Gas Rules

Summary of relevant regulations:

632-010-0014 Drilling Practices

- Surface casing: If subsurface conditions are unknown than it must be placed at a depth below all known potable freshwater. If subsurface conditions are known through previous drilling experience than the casing should be run below the respective depth of the freshwater. All fluid bearing zones above the production horizon must be sealed off
- Surface casing should be cemented to the surface and allowed to set for 12 hours. Casing strings must be pressure tested to reach a compressive strength of 1.5psi times length of casing (1.5psi x ft. of casing = strength).

632-101-0010

- Applications to drill must include the details of the operator's casing and cementing program including casing size and grade, hole diameter and the volume of cement used.

SOUTH DAKOTA

Agency: Department of Environment and Natural Resources, Oil and Gas Section

Statute: Title 45 (Mining, Oil and Gas) Ch.45-9 Oil and Gas Conservation

Regulation: Dpt. of Env. and Nat. Res., Art. 74:10 Oil and Gas Cons.

Summary of relevant regulations:

While South Dakota has a very minimal regulatory scheme, it is important to note that the state only had 153 active wells in 2007, and a peak of 213 wells in 1993. (see Historic South Dakota Oil Production (1954-2007) www.state.sd.us/denr/DES?mining/oil&gas/producti.htm).

74:10:03:14

- The operator must seal off oil, gas or water bearing strata above the producing or injection formation to prevent contents from passing from one stratum to another.

74:10:03:16 Procedures for setting surface casing and production casing

- Surface casing must be sufficient to protect freshwater. A minimum of 100ft. of surface casing must be used. Furthermore, production casing must be employed and cemented to protect freshwater.
- The secretary possesses the power to prescribe variations in casing and cementing procedures based on specific regional characteristics.

TENNESSEE

Agency: State Oil and Gas Board, Department of Environment and Conservation

Statute: Title 60 Oil and Gas

Regulation: 1040 Tennessee State Oil and Gas Board

Summary of relevant regulations:

1040-2-7-.02 Surface Casing

- The operator must submit a casing plan to the supervisor for approval. Surface casing must be placed at least 50ft. below freshwater bearing strata, and cemented from the annular space behind the casing to the surface. The operator must give 12 hours notice to the Supervisor before commencing such operations, and the supervisor has a right to witness the cementing operation.

TEXAS

Agency: Railroad Commission of Texas, Oil and Gas Division

Statute: Title 3 Natural Resources Code

Regulation: Title 16 (Economic Regulation) pt. 1 (Railroad Comm. ff TX) ch.3 Oil and Gas

Summary of relevant regulations:

Tit. 16 §3.13 Casing, Cementing, Drilling, and Completion Reports

- General provisions: Note that this summary only applies to drilling onshore or in inland waters. All casing that will be used in a well must be made of steel that has been hydrostatically tested with applied pressure equal to the maximum pressure the pipe will be subjected to in the well. Any string of casing that exceeds 200ft. in length needs to be pressure tested. The casing must reach a compressive strength of its length time .2 and should not exceed 1,500psi (.2 x ft of casing = psi). It cannot experience a 10% drop in pressure in a period of 30 minutes.
- Surface casing: An operator must obtain a letter from the Texas Commission on Environmental Quality (TCEQ) that states the depth that casing must reach to protect useable quality water. Additionally, an operator may not drill more than 200ft. below this specified depth without approval from the commission. Surface casing is not required for wells that are less than 1,000ft. as long as there are no abnormally high pressures present and production casing is set and cemented from the shoe to the surface by the pump and plug method.

Cementing of Surface Casing

- Casing strings must stand under pressure until the cement has reached a compressive strength of 500psi in the “zone of critical cement” before drilling the plug. “The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200psi.” The zone of critical cement for surface casing is defined as: “the bottom 20% of the casing string, but shall be 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.” Additionally, the cement in the zone of critical cement must have reached a compressive strength of 1,200psi in 72 hours.
- Volume extenders for cementing the surface casing are permissible. However, they may only be used above the zone of critical cement, and must reach a compressive strength of 100psi at the time of drilling and 250psi 24 hours after their placement.
- “In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B.”
- Finally, the commission has authority to provide higher quality cement mixtures when necessary.
- If the operator is using a cement mixture that has not published data concerning its compressive strength than the operator must conduct its own tests. See subsection 2(D) for details.
- The commission, on an individual basis, may approve alternative casing programs. See subsection (G).

Intermediate Casing

- All intermediate casing must be cemented from the shoe to at least 600ft above this point. However, if any production horizon is open to the well bore above the shoe, then the casing must be cemented at least 600ft. above the shallowest producing horizon.

Production Casing

- The basic requirement is the same as intermediate casing, with the addition that all productive horizons must be sealed off

Finally, there is a division of responsibility between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ). This memorandum determines who has responsibility and jurisdiction over particular issues. See 16 TX ADC §3.30 for this memorandum.

UTAH

Agency: Oil and Gas Program, Division of Oil, Gas and Mining

Statute: Title 40 (Mines and Mining) Ch. 6

Regulation: Natural Resources R649

Summary of relevant regulations:

R649-3 Drilling and Operating Practices

- **Well Control:** After blow out prevention equipment (BOPE) has been installed the casing must be tested to the lesser of the manufacturer's rating (working pressure), 70% of the minimum yield pressure of any casing subject to test, or one psi/ft of the last casing string depth. Although this section primarily concerns BOPE equipment, the casing must be pressure tested according to these guidelines; it is cross referenced by R649-3-13, which specifically requires the casing to be tested. The operator must notify the commission 24 hours before conducting any casing tests. R649-3-6 (2.5).
- **Casing program:** Surface casing must reach below all known freshwater levels. Furthermore, the operator must prevent migration of oil, gas and water from one horizon to another. The operator may cement the casing by displacement, pump or plug or any other method. No set times for the cement are required.

VIRGINIA

Agency: Department of Mines, Minerals and Energy, Division of Gas and Oil

Statute: Title 45.1 (Mines and Mining) Ch.12 Oil and Gas

Regulation: Title 4 (Cons. and Nat. Res.) VAC Agency Number 25, Ch. 150

Summary of relevant regulations:

4 VAC 25-150-530 Casing Requirements for Conventional Gas or Oil Wells

- A water protection string must be set at least 300ft. below the surface or 50ft. below the deepest known groundwater horizon (whichever is deeper). This string must be cemented to the surface. The cement must be allowed to set for 8 hours to achieve a calculated compressive strength of 500psi. According to the regulation a coal protection string may be used as a water protection string, which is covered in subsection B.

WASHINGTON

Agency: Department of Natural Resources, Division of Geology and Earth Resources

Statute: Title 79 (Public Lands) Ch.79.76 Geothermal Resources

Regulation: Title 332 Department of Natural Resources

Summary of relevant regulations:

332-17-110 Casing Requirements

- Washington's regulatory scheme makes it clear that the casing specifications are guidelines that reflect minimum requirements. The following specifications provide guidelines for submitting an application for a permit. Exact casing specifications are established on an individual well basis.
- Surface casing: Must reach a depth of 200ft. and at least 100ft. into the bedrock. The standard proposed depth of the casing should be the depth of the well plus 10%
- Intermediate casing: It is required when the following are expected/known to be encountered: anomalous pressure zones, cave-ins, washouts, abnormal temperature zones, uncased freshwater aquifers, uncontrollable lost circulation zones or other drilling hazards. It should be cemented from the shoe to the surface if possible. Additionally, it is possible to use a liner as an intermediate casing. If used, it must be tested by fluid entry or pressure tested.
- Production casing: "This casing may be set above or through the producing or injection zone and cemented above the objective zones. Production casings shall be cemented to the surface or lapped into the intermediate string. Overlap shall not be less than 30 meters (100 feet) and shall be pressure tested. Lap or casing failure shall require repair, recementing, and successful retesting."
- Pressure Testing: Before drilling out the casing shoe any casing string that reaches a depth of 500ft. or less must be pressure tested and meet a compressive strength of 500psi. Casing strings that reach a depth of more than 500ft. must be pressure tested to meet 1,000psi, or .2psi time every foot of the casing string (.2psi x ft =strength) (whichever is greater).
- All casing must be cemented to isolate all overlying formation fluids to prevent the movement of fluid into possible freshwater zones.
- The operator must submit a casing plan for approval in the application to drill. See 332-17-100.

WYOMING

Agency: Oil and Gas Conservation Commission

Statute: Title 30 (Mines and Mineral), Ch.5 Oil and Gas

Regulation: Oil and Gas Conservation Commission,

Summary of relevant regulations:

WY ADC Oil Gen ch.3 §22 General Drilling Rules

- Surface casing: Must be run to a depth below all utilizable domestic freshwater. All freshwater flows encountered during drilling must be recorded and reported to the commission. If subsurface pressures are unknown the casing must be big enough to allow for intermediate casing strings. Furthermore, it must be set in an impervious formation and cemented to the top by the pump and plug method.
- Pressure testing: Cemented casing string must stand under pressure until the cement at the shoe reaches a compressive strength of 500psi. All other cements must reach 100psi measured at 80 degrees Fahrenheit.
- The operator must submit a casing plan in the application to drill.
- Note that there are special rules for wells drilled within a special sodium drilling area.

The authors of *Selected Topics in State and Local Regulation of Oil and Gas Exploration and Production* are the first to tackle the research and analysis needed on this issue. Across the country, communities with oil and gas activities are calling for smarter health and environmental safeguards. Existing standards for this complicated industry vary greatly, and in many places may not reflect technological advancements or the best available information about health and environmental impacts. This paper will be a vital tool for citizens and policymakers alike.

--- Amy Mall, Natural Resources Defense Council