BRINGING REAL INFORMATION ON ENERGY FORWARD
Environmental and Regulatory Considerations Associated with the American Oil and Natural Gas Industry

Prepared for:

Independent Petroleum Association of America (IPAA)

and

The Liaison Committee of Cooperating Oil and Gas Associations

Prepared by:

Advanced Resources International, Incorporated

April 24, 2009

INTRODUCTION

For the last several years, a number of environmental organizations have been pursuing an aggressive campaign to push for greater federal environmental regulation over U.S. oil and natural gas exploration and production (E&P) operations. They allege that federal U.S. statutes and regulations allow U.S. oil and natural gas producers to circumvent environmental requirements imposed on other industries.[1]

The U.S. oil and natural gas industry is concerned that this set of regulatory proposals, if implemented, could have adverse impacts on the economics of U.S. operations, and thus on U.S. oil and natural gas supplies, prices, and other economic considerations.[2]

This report provides the American public with information on how American oil and natural gas producers and state regulatory agencies effectively and safely manage environmental and safety risks related to development and production activities, as addressed under federal U.S. statutes such as the Safe Drinking Water Act (SDWA), Clean Water Act (CWA), Clean Air Act (CAA), Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, or Superfund), Resource Conservation and Recovery Act (RCRA), and the "public right-to-know" provisions of the Emergency Planning and Community Right-to-Know Act (EPCRA).

This document demonstrates how regulations currently in place adequately and appropriately protect the public and the environment, that American oil and gas producers pursue their operations with aggressive but measured approaches to protecting the environment, and that both state regulatory programs and industry approaches to environmental protection are evolving in response to changing resource targets, environmental considerations, and market factors.

A companion document to this study demonstrates the economic value American oil and natural gas producers bring to local communities, states, and the nation. In addition, that report discusses the potential energy supply and economic implications associated with the imposition of more stringent regulatory requirements on American oil and natural gas producers.

CONTINUALLY IMPROVING ENVIRONMENTAL PERFORMANCE OF AMERICAN OIL AND NATURAL GAS PRODUCERS

By almost any measure, the environmental performance of the American oil and natural gas industry has continued to improve.

This improved performance is demonstrated by several important indicators:

- Since 1990, environmental expenditures of the oil and natural gas production sector have amounted to over $31 billion, averaging nearly $1.9 billion per year for last decade, an increase of over 100% since 1990.[3] These environmental expenditures represent costs incurred for the prevention, control, abatement or elimination of environmental impacts,

---

[1] http://www.nrdc.org/land/use/down/contents.asp

[2] See, for example, IPAA Testimony to the House Oversight and Government Reform Committee in October 2007 (http://ipaa.org/issues/testimony/IPAATestimony-HouseOversiteGovtReform10-31-2007.pdf)

[3] American Petroleum Institute, *Environmental Expenditures by the U.S. Oil and Natural Gas Industry,* January 8, 2009 (http://www.api.org/statistics/accessapi/surveys/upload/2009-005_ENVIRON_EXPENDITURES.pdf(http://www.api.org/statistics/accessapi/surveys/upload/2009-005_ENVIRON_EXPENDITURES.pdf)

associated with ongoing activities to comply with regulations and to minimize or treat output streams.[4].

- Based on data compiled by the U.S. Coast Guard, between 2001 and 2005, the volume of oil spilled in U.S. waters declined by 59%. Similarly, the number of spills over this same time period decreased by 60%.[5] This represents the spills from all petroleum industry operations, both upstream and downstream, and not just those related to E&P operations.

- Since its inception in 1993, production sector participants have voluntarily participated in the U.S. Environmental Protection Agency's (EPA's) Natural Gas STAR program. These efforts have eliminated emissions of 417 billion cubic feet (Bcf) of methane (a potent greenhouse gas, or GHG).[6] The entire oil and gas industry, including the production, processing, transportation, and distribution sectors, has eliminated nearly 677 Bcf since 1993. One study has estimated that the petroleum industry (upstream and downstream) has spent $42 billion between 2000 and 2006 to reduce fugitive methane emissions.[7]

<u>New technologies and industry approaches lead to environmental benefits.</u>

Technology progress in the oil and natural gas industry has continued to push the frontiers of the industry. In the U.S., the most mature hydrocarbon province in the world, the average reserve additions per successful well drilled more than doubled in the last decade, and drilling success rates has improved from about 75% to nearly 90%. The application of evolving technology is also allowing new reserves to be added to older, mature fields each year. Today, an initial discovery could grow by as much as 10 times through additional field delineation, infill development, and application of new technology. As a consequence, the U.S. has been able to replace the natural gas reserves it has produced for 10 of the last 11 years, and replaced the crude oil reserves it has produced in 6 of the last 8 years.[8]

These technological advances have enabled oil and natural gas producers to:

- <u>Drill fewer wells to add the same reserves</u>. Today, the U.S. industry adds twice as much oil and natural gas to the Nation's reserve base per well than in the 1980s.
- <u>Generate lower drilling waste volumes</u>. Today, the same level of reserve additions is achieved with 35% of the generated waste from drilling operations.[9]
- <u>Leave smaller footprints and less surface disturbance</u>. The average well site footprint today is 30% of the size it was in 1970, and through the use of extended reach drilling, an average well can now contact over 60 times more subsurface area.[10]

---

[4] Expenditures are the incremental costs reported by a unit in a facility that would not have been incurred if environmental issues had not been considered.
[5] American Petroleum Institute, *Oil Spills in U.S. Waters*, 2007 (http://www.api.org/ehs/water/spills/upload/OIL_SPILLS_REPORT_LO.pdf)
[6] http://www.epa.gov/gasstar/accomplishments/index.html
[7] Tanton, Thomas; Michelle Michot Foss, Mariano Gurfinkel, and Dmitry Volkov, *Key Investments in Greenhouse Gas Mitigation Technologies by Energy Firms, Other Industry and the Federal Government*, May 2008 (http://www.api.org/ehs/climate/new/upload/Investments_GHG_Mitigating_ES_4_2008.pdf)
[8] Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids *Reserves*, 2007 Annual Report, DOE/EIA -0216 (2007) Advanced Summary, October 2008 (http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary/current/adsum.pdf)
[9] American Petroleum Institute, *Overview of Exploration and Production Waste Volumes and Waste Management Practices in the United States*, May 2000 (An update to this study was initiated in late 2008)
[10] William Harrison, Kansas Geological Survey, presentation at the 2002 Meeting of the American Association of Petroleum Geologists, Denver, Colorado

- Reduce air pollution. Greater efficiency and improved technologies in development and production means less energy consumption per barrel of oil and/or Mcf of natural gas discovered and produced, and thus less air pollution per unit produced as well.

The American oil and natural gas industry is also improving environmental performance in response to public and market expectations.

Market and public expectations today have as much an impact on oil and natural gas industry environmental performance as does explicit regulatory requirements, Traditionally, industry activities focused on environmental protection, worker safety, and social justice were part of each company's regulatory and compliance offices. But this is changing. Throughout the industry, environmental performance is increasingly being considered as an important contributor to the bottom line, or at least, an important factor impacting corporate image. Consequently, the oil and natural gas industry is responding to a market increasingly driven, at least in part, by desires for simultaneously improved environmental and social performance and growth and profitability.

For example, more and more companies are reporting progress on environmental and social performance with a comparable level of rigor and sophistication as that exhibited in their financial reports. Efforts such as the Global Reporting Initiative (GRI),[11] the Oil & Gas Industry Guidance on Voluntary Sustainability Reporting,[12] and the Carbon Disclosure Project[13] are just a few examples of such market encouragement to report on environmental and safety performance. Finally, corporate environmental and social performance is becoming an increasingly important factor in ensuring a "social license to operate" in many locations.[14]

Moreover, the industry is pursuing a number of projects to voluntarily help to facilitate a positive environmental impact:

- Apache Corporation has just finished a program that resulted in planting 1 million trees to reduce GHG concentrations in the atmosphere.[15]
- Devon Energy Corp is working to conserve millions of barrels of water on an annual basis. Their water recycling efforts have allowed them to minimize consumption of fresh water resources in addition to reducing the volume of water that must be disposed.[16]
- Fidelity Exploration & Production Company sponsored a three-year soil and crop testing program called the Tongue River Agronomic Monitoring and Protection Program (AMPP), to monitor water and soil conditions for any potential impacts from the discharge of water produced in conjunction with coalbed natural gas.[17]
- On leases in the Wamsutter natural gas field in south-central Wyoming, BP America drilled multiple wells on single pads and located centralized production facilities outside of critical wildlife habitat. The company also retrofitted existing drilling rigs with cleaner engines and incorporated "green" completions into drilling operations to reduce methane and nitrous oxide emissions.

---

[11] http://www.globalreporting.org/Home
[12] http://www.oilandgasreporting.com/downloads/SustainabilityReporting.pdf
[13] http://www.cdproject.net/
[14] The Ethical Funds Company, Christian Brothers Investment Services, Interfaith Center on Corporate Responsibility, *Reducing Risk, Protecting Communities & Securing Social License to Operate: a Shareholder Perspective on Free, Prior and Informed Consent*, February 2008
[15] http://www.apachecorp.com/explore/explore_features/browse_archives/View_Article/?docdoc=783
[16] http://www.iogcc.state.ok.us/Websites/iogcc/Images/Final_2008_Stewardship_Winners_Booklet.pdf
[17] http://www.fidelityoil.com/docs/fep_stewardship.html

- Devon Energy Corporation has voluntarily restored habitat for the lesser prairie chicken and sand dune lizard on old, abandoned operations in the Permian Basin, while monetary contributions have supported trout habitat restoration in the San Juan Basin. Devon also drills multiple wells from single pads while conducting intensive interim reclamation. Air quality impacts in the San Juan Basin are reduced by using "green" completions during drilling and low-emission compressors and solar-powered pumps on production equipment.
- Questar Exploration and Production is using a sophisticated liquid-gathering system to significantly reduce the amount of truck traffic and well site production equipment in the field. The company also reduced the footprint of its operations by directionally drilling multiple wells from single well pads, which is becoming its standard practice.[18]

EFFECTIVENESS OF STATE MANAGEMENT AND REGULATION OF OIL AND NATURAL GAS EXPLORATION AND PRODUCTION

In the following sections, information is presented to provide some insight on the rationale for state-based regulation and oversight of oil and natural gas production operations, current state approaches for regulating all aspects of these operations, state resources devoted to oversight of these activities, and collective state agency efforts to review and improve state-based regulatory programs in order to oversee oil and natural gas operations, adequately protect the environment, and properly account for the real differences in operations, geology, and environmental settings among the different producing states.

State-based regulation and oversight of oil and natural gas operations is well established, with a long history.

Many credit the modern environmental movement as beginning in 1970 at the first "Earth Day," which brought environmental considerations broadly into the public consciousness. In the U.S., the federal EPA was formed that year, and during the decade of the 1970s, a large number of new federal environmental laws were passed and implementing regulations were promulgated.

In reality, while the first "Earth Day" in 1970 may mark the beginning of widespread public awareness of the need for government to facilitate environmental protection, that historic event was actually the product of years of effort led by various groups.[19] Oil and natural gas producing states were among the first to promote conservation of oil and natural gas and to work to ensure it is produced in harmony with the environment. Most federal environmental laws are predicated on the existence of state regulatory programs; in fact, many were based in large part on existing programs. Most federal statutes contain provisions that allow state regulatory programs to assume primacy for regulating in a particular arena. This essential structure is based on the reality that these states have effective regulatory programs and that the federal government structure is not designed to manage day-to-day regulation of many industry operations.

Examples of state programs in the oil and natural gas exploration and production sector that predate the federal laws include the following:

- Since the 1930s, the Texas Railroad Commission (TRRC) has been a leader in the regulation of oil and natural gas -- one that has been recognized throughout the world. In April 1935, the

---

[18] http://www.blm.gov/wo/st/en/info/newsroom/2008/may_08/NR_052208.html

[19] Interstate Oil and Gas Compact Commission, *Stepping Lightly: Reducing the Environmental Footprint of Oil and Gas Production*, (http://iogcc.myshopify.com/collections/frontpage/products/steeping-lightly-reducing-the-environmental-footprint-of-oil-and-gas-production)

state legislature enacted a general oil and gas law, prohibiting the production of oil and gas in such a manner as to cause waste, and delegating to the TRRC the duty to adopt the necessary orders to prevent wasteful operations.[20] In the late 1960s, five years before the passage of the federal Clean Water Act, Texas passed its own law protecting water.[21]

- The Oklahoma Corporation Commission began regulating oil and natural gas in 1914 when it restricted oil drilling and production in the Cushing and Healdton fields to prevent waste when production exceeded pipeline transport capacity. In 1915, the Legislature passed the Oil and Gas Conservation Act, which expanded oil and natural gas regulation to include the protection of the rights of all parties entitled to share in the benefits of oil and natural gas production.[22]
- In Arkansas, Act 105 of 1939 repealed existing oil and natural gas laws and regulations and created the Oil and Gas Commission to oversee oil and gas conservation and production requirements.[23]
- In California, the petroleum industry began in the 1860s. As the industry grew, so did the recognition that controls were necessary to protect the environment and oil, natural gas, and geothermal resources. In 1915, the California Legislature established a branch of the State Mining Bureau called the Department of Petroleum and Gas.[24] Several years before 1915, such controls were undertaken locally in Kern and Fresno Counties. In 1929, the department was separated from the State Mining Bureau and moved to the Department of Natural Resources.[25]
- In Utah, the Oil and Gas Conservation Commission was established in 1955 to prevent the waste of oil and natural gas, encourage conservation, and protect the correlative rights of oil and natural gas owners. In 1968, the Division of Oil and Gas Conservation was formed as a part of the Department of Natural Resources. In 1975, the Utah Legislature assigned the Division the responsibility for administration of the Mined Land Reclamation Act and it became the Division of Oil, Gas and Mining. The Act's primary function was to "prevent conditions detrimental to the general safety and welfare of the citizens of the state of Utah."[26]
- In New York, state legislation to regulate the oil, natural gas, and solution mining industries began in the late 1800s. As early as 1865, legislation was enacted to control the location and amount of crude oil that could be stored, primarily to ensure public safety. In 1879, legislation was passed requiring plugging of abandoned wells to prevent freshwater contamination by oil and gas, and amendments passed in 1882 imposed a maximum jail sentence of one year on operators who abandoned a well without plugging it. In 1963, the State Legislature repealed all previous oil and natural gas legislation and amended the Conservation Law to give the New York Department of Environmental Conservation (DEC) greater authority over wells drilled in the fields developed after 1963. The purpose of this law was to foster, encourage, and promote the development, production, and utilization of the natural resources of oil and gas in a manner that would prevent waste, increase ultimate recovery, and protect correlative

[20] http://www.rrc.state.tx.us/about/history/index.php
[21] http://www.rrc.state.tx.us/about/history/chronological/chronhistory03.php
[22] http://www.occ.state.ok.us/Divisions/COMM/commission-history.htm
[23] http://www.state.ar.us/dfa/budget/07_09_budget_manual_pdf_files/manual_3/summary/0440_oil_&_gas_before_merger_pg399.pdf
[24] ftp://ftp.consrv.ca.gov/pub/oil/laws/laws_1915.pdf
[25] ftp://ftp.consrv.ca.gov/pub/oil/publications/pr11.pdf
[26] http://ogm.utah.gov/division/About%20Us/HISTORY.HTM

rights of all the interests involved, and contained provisions regarding well spacing, wasting oil and gas, flaring gas, protecting surface and groundwater supplies, and well plugging.[27]

- In Pennsylvania, early regulation of the oil and natural gas industry dates back to the late 1880s when operators were required to plug wells to protect oil bearing zones and to protect fresh water. In the early 1900s, legislation specifying well plugging procedures was enacted. The Pure Streams Act of 1937 provided the first pollution abatement controls. Pollution was broadly construed to mean the discharge or effects of noxious or deleterious substances "rendering unclean the waters of the Commonwealth to the extent of being harmful or inimical to the public health, or to animals or aquatic life, or to the use of such waters for domestic water supply, or industrial purposes, or for recreation." In 1984, after six years of debate, the Oil and Gas Act was adopted, providing for a comprehensive regulatory program which tied together requirements for environmental protection with oil and natural gas well permitting, bonding, drilling, operation, inactive status, reporting and plugging.[28]
- In Ohio, the Division of Oil and Gas (the duties of which now lie with the Division of Mineral Resources Management) was created in 1965 to "…assure protection of public health, safety and the environment; promote the orderly and efficient development of oil and gas reserves; and, assure conservation of natural resources."[29]

Federal regulations are often written to address industrial and manufacturing settings, which are often inappropriate for the oil and natural gas production industry.

Issues vary from state to state, and experienced regulators across the nation have shown great leadership in protecting our environment. Many times, federal regulations offer a "one size fits all" approach, which does not effectively regulate the oil and natural gas industry. Most federal environmental laws were developed on a model based on manufacturing facilities that are large, generally located near urban areas and present concentrated sources of emissions or discharges. This model is generally inconsistent with the nature of oil and natural gas exploration and production activities, which are generally rural in nature, with many small operations spread over large areas; take place in a wide variety of geologic, environmental, and operational settings; and are conducted by a wide variety of operators – ranging from large, integrated, global oil and gas companies, to small "mom and pop" operations producing from just a few wells.

In general, state agencies responsible for regulating oil and natural gas activities have broad powers to regulate, permit, and enforce all activities – from drilling, completing, and stimulating a well; to production operations, to managing and disposing of wastes, to abandoning and plugging the well and reclaiming the production site. Different states have pursued different approaches to this regulation and enforcement, but their laws generally give the state oil and gas director or the agency the discretion to require whatever is necessary to protect the human health and the environment.

In addition, most states generally have a general prohibition against pollution from oil and natural gas drilling and production operations. A majority of the state requirements are written into rules or regulations; however some are added to permits on a case-by-case basis as a result of an environmental review, on-the-ground operational inspections, public comments, or commission hearings.

---

[27] New York State Department of Environmental Conservation, *Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program*, Volume 1, 1988, Chapter IV (http://www.dec.ny.gov/docs/materials_minerals_pdf/dgeisv1ch4.pdf)
[28] http://www.strongerinc.org/documents/Revised%20PA%20Final%20Report.pdf
[29] http://www.strongerinc.org/reviews/reviews.asp (state of Ohio review)

Existing state regulatory frameworks address all aspects of American operations.

States have rules in place to regulate oil and natural gas operations that include such things as financial surety, permitting, construction, operation, pollution prevention, and reclamation. States require operators to obtain a permit before drilling and operating a well. The application for this permit may request data about the well location, construction, operation, and reclamation. If the well is to be fractured, information about the fracturing program is also generally required to be included on the application. Agency staff members review the application for compliance with regulations and to assure adequate environmental safeguards, and if necessary, perform a site inspection before permit approval. Most states require notice to affected landowners and/or the public, and provide the opportunity for objections to drilling permits. Any protestations are then investigated by the agencies for evidence of possible adverse impacts. Most states have implemented safeguards even beyond these: most require operators to post a bond or other financial security when obtaining a drilling permit to insure compliance with the state regulations and to make sure that there are funds available to properly plug the well and restore the well site once production ceases; and many obligate producers to notify the state agencies of any significant new activity through a "sundry notice" or a new permit application so that the agency is aware of that activity and can review it.

In fact, every aspect of oil and natural gas activity in the states generally is addressed by existing statutes and regulations, as illustrated in Table 1 for selected states.

States work together to review and improve state programs that oversee oil and natural gas operations

Almost since their formation, organizations like the Interstate Oil and Gas Compact Commission (IOGCC), the organization that represents the Governors of oil and natural gas producing states, have promoted state-based regulation resulting in sound environmental practices.[30] Since its inception in 1935, the IOGCC has promoted sound oil and natural gas environmental policy; and its member states continuously seek new and innovative techniques to produce these much-needed resources without compromising the environment.

The IOGCC also serves as a forum for state regulators to share their ideas and viewpoints to strengthen state programs that oversee oil and natural gas production. One of the many ways in which this has been accomplished is through the drafting of model statutes. Moreover, the IOGCC annually publishes a *Summary of State Oil and Gas Regulations for Oil and Gas Production*.[31]

Another important service provided by the IOGCC has been the issuing of suggested guidelines to be used by the states or by those in the oil and natural gas industry for environmental protection. For example, it has recently published important guidance documents such as *A Guide to Practical Management of Produced Water from Onshore Oil & Gas Operations in the United States*[32] and the *Adverse Impact Reduction Handbook*[33] for state regulators and operators to use to reduce the impact of their operations on the environment.

[30] http://www.iogcc.state.ok.us/environmental-stewardship
[31] http://iogcc.myshopify.com/collections/frontpage/products/summary-of-state-statutes-and-regulations-for-oil-and-gas-production-cd-rom-2007
[32] http://iogcc.myshopify.com/collections/frontpage/products/a-guide-to-practical-management-of-produced-water-from-onshore-oil-gas-operations-in-the-united-states-2006
[33] http://iogcc.myshopify.com/collections/frontpage/products/adverse-impact-reduction-handbook

Table 1
Stages and Associated Regulatory Requirements for Oil and Natural Gas Development and Production in Selected States

Category of Activity	Texas	California	Colorado	Oklahoma	Arkansas	Pennsylvania
Identification	Rule 1	CCR 1722.1; Law 3200-3202	Rule 302	OAC 165:10-1-10	ACA Title 15, Chapter 72, Rule B-13	25 Pa. Code §78.11 to 18
Exploration & Leasing	Rule 31 (leasing), 5 (seismic drilling), 100 (seismic holes and core holes)	CCR 1722.1	Rule 333 (seismic operations)	OAC 165:10-3-1 (well permiting); 165:10-7-31 (seismic, strategraphic operations)	ACA Rule B-42 (seismic)	
Drilling	Rule 5 (permit application), 6 (multiple completions), 7&10 (strata to be sealed off), 13, 17, 18, 19, 22 (protection of birds), 30 (water protection), 37&38 (well spacing/density), 99, 100	Law 3203 (permit); CCR 1721, Law 3600-3609 (spacing), 1722.5, 1941-1942, Law 3219 (blowout prevention), 1722.6 (drilling fluid program); 1930-1933; Law 3204-3209 (bonding)	Rule 216 (comprehensive drilling plans); 303 (permitting); 304 (financial assurance); 305 (notice and comment); 306 (consultation); 317 (General drilling rules); 318 (Location); 321 (Directional drilling); Rule 603 (drilling, well servicing, and high density areas); 606 (air and gas drilling); 608 (coalbed methane wells); 907 (management of E&P waste); 1002 (site prep)	OAC 165:10-1-10 (bonding); 165:10-1-20 to 28 (spacing), 165:10-3-1 to 5	ACA Rule B-2 (bonding), Rule B-3 (spacing)	25 Pa. Code §78.11 to 18 (permits), §78.71 to 78; §78.301 to 314 (bonding)
Water Protection	Rule 8, 30	CCR 1770-1778	Rule 209; Rule 317B	OAC 165:10-1-13; 165:10-7-1 to 32	ACA Rule B-26	25 Pa. Code §78.51 to 66
Pit Construction	Rule 8	CCR 1770	Rule 902, 903, 904, 905	OAC 165:10-1-17	ACA Rule B-26	25 Pa. Code §78.56
Sour Gas	Rule 36		Rule 607	OAC 165:10-1-16	ACA Rule B-41	25 Pa. Code §78.77
Air Quality	30 TAC Setions 116.601-615; 1116.620; 116.353	CCR 1780-1788, Law 3865 (methane gas hazards reduction)	Rule 804, 805, 912	OAC 252:100		
Completion and Stimulation						
Cementing, Surface Casing	Rule 13	CCR 1722..2-1722.4; 1935, Law 3220-3223	Rule 317	OAC 165:10-3-3 to 4	ACA Rule B-15, Rule B-29	25 Pa. Code §78.81-87
Tubing	Rule 13	CCR 1950-1954	Rule 317	OAC 165:10-3-3 to 4	ACA Rule B-23	25 Pa. Code §78.81-87
Logging & Testing	Rule 16	CCR 3210-3216; 1936; Law 3211-3215 (logging, coring, reporting)	Rule 317, 603	OAC 165:10-3-25 to 26		25 Pa. Code §78.123
Stimulation	Rule 13, 16	CCR 1950-1954	Rule 317, 603	OAC 165:10-3-10		
Production Operations						
Normal Operations	Rule 8, water protection and waste mgt), 23 (vacuum pumps), 24 (check valves), 25, 26, 27, 28, 30 (water protetion), 31,32,	CCR 1724; 1770-1778; Law 3270	Rule 328, 329 (measurement of oil, gas), 330 (measurement of produced water); 331 (vacuum pumps); 332 (artificial lift); 604 (oil and gas facilities); 608 (coalbed methane wells); 800 series (aesthetic and noise control); 907 (management of E&P waste)	OAC 165:10-3-29 to 40; 165:10-1-13; 165:10-7-1 to 32	ACA Rule B-26	
Air Quality	30 TAC Setions 116.601-615; 1116.620; 116.352	CCR 1780-1788, Law 3865 (methane gas hazards reduction)	Rule 804, 805, 912	OAC 252:100	Reg No. 18&26, Arkansas Air Pollution Control Code	
Accidents/Blowouts	Rule 20		Rule 327	OAC I65:10-3-4	ACA Rule B-18 (prevention), Rule B-34 (Reporting)	25 Pa. Code §78.72
NORM		CCR 30100-30543		OAC 165:10-11-9	Section 7 "Naturally Occurring Radioactive Material (NORM)" of the Arkansas State Board of Health Rules and Regulations for Control of Sources of Ionizing Radiation.	
Spills	Rule 91; 16 Texas Administrative Code §3.8, 16 Texas Administrative Code §3.21, and Waste Minimization in the Oil Field at http://www.rrc.state.tx.us/divisions/og/key-programs/manual/index.html.)	CCR 1773-1774, 8589.7; Special criteria for oil spill reporting in the San Joaquin Valley	Rule 906	OAC 165:10-7-5	ACA Rule B-26, 34	25 Pa. Code §78.66
Injection Operations						
Air Quality	30 TAC Setions 116.601-615; 1116.620; 116.351		Rule 804, 805, 912	OAC 252:100	Reg No. 18&26, Arkansas Air Pollution Control Code	
Disposal	Rule 9, 47	CCR 1960-1966	Rule 325 (disposal), 326 (MIT); Rule 404 (casing & cementing of injection wells); 712	OAC 165:10-5-1to 15, 165:5-7-27	ACA Rule C-7	25 Pa. Code §78.17
Enhanced Recovery	Rule 46; 50		Rule 400 series	OAC 165:10-5-1to 15, 165:5-7-27	ACA Rule C-8	25 Pa. Code §78.17
Well Closure						
Well P&A	Rule 14, 15, 16, 35	CCR 1723; 1980-1981; Law 3228-3232	Rule 311, 319	OAC 165:10-11-1 to 9	ACA Rule B-7, B-8	25 Pa. Code §78.91-98
Well Site Cleanup	Rule 91		Rule 208, 909, 910, 1000 series,	OAC 165:10-11-1 to 9	ACA Rule B-26	

In 1990, the IOGCC and EPA cooperatively launched a state review process of state regulatory programs. The State Review of Oil and Natural Gas Environmental Regulations -- or STRONGER -- was formed in 1999 to carry forward this process in coordination with the IOGCC, continuing the program IOGCC originally initiated.[34]

The State Review Process is an outgrowth of a 1988 regulatory determination by EPA which, after extensive study documented in a report to Congress, found that "…existing state and federal regulations are generally adequate to control the management of oil and gas wastes" including drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas.[35]

The State Review Process brings together representatives from the states, the oil and natural gas industry, and environmental advocates to review state environmental regulatory programs by multiple-stakeholder teams using a set of published national guidelines (*Guidelines for the Review of State Oil and Natural Gas Environmental Regulatory Programs* or the Guidelines) that establish a baseline of performance for state oil and natural gas environmental regulatory programs.

The Guidelines contain suggested minimum requirements for environmental aspects of state oil and gas regulatory programs and are reviewed and updated periodically to address emerging issues, reflect new information and experience, and adapt to changing circumstances. They address all areas needed for an effective program, including: (1) statutory authority which adequately details the powers and duties of the regulatory body; (2) statutory authority to promulgate appropriate rules and regulations; (3) statutes and implementing regulations which adequately define necessary terminology; (4) provisions to adequately fund and staff programs; (5) mechanisms for coordination among the public, government agencies, and regulated industry; and (6) technical criteria for exploration and production waste management practices.

The technical criteria for E&P waste management practices address waste characterization, waste management hierarchy, pits, land applications, tanks, and centralized and commercial facilities. In most cases, these criteria are general in scope, allowing states to establish and implement specific performance standards and design specifications based on site-specific or regional differences in geology, hydrology, climate, and waste characteristics.

The purpose of the State Review Process is to evaluate state oil and gas environmental regulatory programs against specific published guidelines, to measure the effectiveness of program implementation; to document program strengths; to identify and recommend areas for program improvements; to share new or innovative program elements; and to promote consistency among state programs, while allowing flexibility to address unique circumstances.

Twenty one states, including all of the largest oil and natural gas producing states, have undergone initial state reviews (Table 2). Ten states have undergone follow-up reviews to assess the state's progress, and two – Oklahoma and Pennsylvania -- have had two follow-up reviews.

---

[34] The state review process is a non-regulatory program and relies on states to volunteer for reviews. EPA and the U.S. Department of Energy have provided grant funding to STRONGER to support its activities and the American Petroleum Institute has provided no-strings attached funding to support the state review process. See www.strongerinc.org.

[35] See *Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes*, July 6, 1988 (53 FR 25466) at http://www.epa.gov/epaoswer/other/oil/index.htm

Table 2
States Subject to STRONGER Review Process[36]

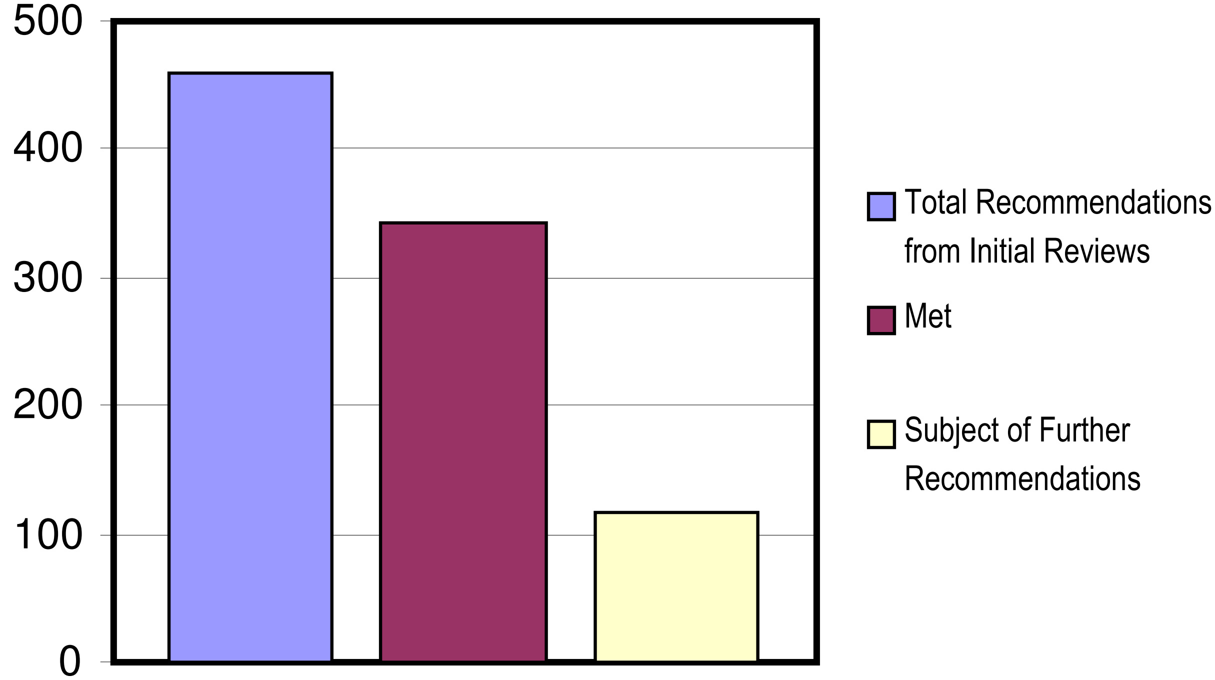
STATE	Year of Initial Review	Year(s) of Follow-Up Review(s)
Alaska	1992	
Arkansas	1993	
California	1993	2002
Colorado	1996	
Illinois	1996	
Indiana	2004	
Kansas	1993	
Kentucky	1995	2006
Louisiana	1994	2004
Michigan	2003	
New Mexico	1994	2001
New York	1994	
North Dakota	1997	
Ohio	1995	2005
Oklahoma	1992	1995, 2005
Pennsylvania	1992	1997, 2004
Tennessee	2007	
Texas	1993	2003
Virginia	2003	
West Virginia	1993	2002
Wyoming	1991	1994

And, for the most part, states have implemented most of the recommendations made as part of the State Review Process. As shown in Figure 1, to date, of the 459 total recommendations made, 343 (75%) have been met.[37] In many cases, recommendations cannot be implemented without enacting legislation; i.e., not all recommendations can be implemented solely by the specific agency and/or program being reviewed. Some also may require resources beyond which the agency has access to at the time the recommendations are made.

The character of the State Review Process itself is the main reason for its success. The program is an open, stakeholder-driven process, rather than a bureaucratic or political oversight exercise between federal and state agency personnel. Importantly, regulatory programs are evaluated against agreed-upon standards. The program's evaluation of performance is focused on environmental results. The reviews focus on both program strengths and aspects needing improvement. Finally, and most importantly, the State Review Process has resulted in identifiable, measurable improvements to state regulatory programs and the environment.

[36] http://www.strongerinc.org/reviews/reviews.asp
[37] Lori Wrotenbery, STRONGER, presentation made at the 2009 SPE Americas E&P Environmental and Safety Conference, San Antonio, Texas, March 25, 2009

Figure 1
Progress Documented Through Follow-up STRONGER State Reviews
State Response to Recommendations



Moreover, individual state agency efforts to revise/update regulatory programs for oil and natural gas operations highlight this commitment.

In addition to the STRONGER state reviews, many states have initiated actions on their own to upgrade their state programs, as described below.

- In December, 2008, the Colorado Oil and Gas Conservation Commission (COGCC) recommended new state rules to protect public health, safety, and welfare, including the environment and wildlife resources. They also implemented new statutory authority and updated existing regulations where appropriate. On March 26, 2009, the state senate passed legislation adopting these rules, which Governor Ritter planned to sign.[38] These new rules were adopted primarily to address concerns created by the recent unprecedented increase in well permitting and oil and natural gas production in Colorado. They are the result of a COGCC reevaluation of its regulatory scheme to ensure that its rules are appropriate for the heightened level and broader geographic extent of activity in the state.[39]
- In May, 2008, the New Mexico Oil Conservation Commission approved an order, more commonly known as the Pit Rule, which imposes more stringent requirements for oil field waste pits, below grade tanks, and the use of closed loop systems during oil and gas operations. The rule prohibits the use of unlined pits for oil field waste, and establishes new

[38] "OIL AND GAS: Colo. Legislature passes stricter drilling regulations," *Greenwire*, March 26, 2009
[39] http://cogcc.state.co.us/

requirements for lining the oil field pits. The new rule also requires that the abandoned pit waste be removed to a landfill and the pit site be restored, unless the operator can demonstrate that the pit waste will not be detrimental to the environment.[40] Lauded by environmentalist as one of the most stringent in the country,[41] industry representatives felt that the rule is "overzealous" and "… provides no real additional environmental benefits."[42] Since their original approval, Gov. Bill Richardson has more recently directed state energy officials to consider modifying these new rules. The state oil and gas industry and some state lawmakers have pressed their case to the governor given concerns about the fiscal impact of the rule given the falling oil and gas prices the economy's severe downturn.[43]

- To address concerns surrounding new developments in the Marcellus and Utica Shales of New York, where development is beginning to occur in areas that have not previous been the target of much interest, the New York State Department of Environmental Conservation (DEC) initiated a process to prepare a Supplemental Generic Environmental Impact Statement (GEIS) to update a 1992 GEIS.[44] The particular focus in the Supplemental GEIS is on the potential environmental impacts of gas well development using hydraulic fracturing, particularly the large volumes of water needed for its use. In February 2009, the DEC released a final scope for the supplemental GEIS. Aspects of high-volume hydraulic fracturing identified in this draft scope for further review include the potential impacts of: (1) water withdrawals, (2) transportation of water to the site, (3) the use of additives in the water to enhance the hydraulic fracturing process, (4) space and facilities required at the well site to ensure proper handling of water and additives, (5) removal of spent fracturing fluid from the well site and its ultimate disposition, and (6) potential impacts at well sites where multiple wells will be drilled during a three-year period. Noise, visual and air quality considerations are noted, along with the potential for cumulative and community impacts. The current plan is for a draft Supplemental GEIS to be released for public comment sometime in the spring of 2009.[45]
- In February, 2009, the Texas Railroad Commission (TRRC) approved new rules that will place natural gas production and flow lines in heavily populated areas under the state's safety jurisdiction. These new state pipeline safety standards for production and flow lines exceed federal guidelines. Production and flow lines typically are low-pressure pipelines that transport natural gas from a well to a gathering line. A gathering line gathers natural gas from several wells and delivers it to a natural gas plant or transmission pipeline. Previously, production and flow lines in urban populated areas were unregulated under federal law and had no explicit safety requirements. These new rules now require that production and flow lines in populated areas be operated and maintained according to state pipeline safety rules. These rules address several factors including design, construction, operating pressures and testing, emergency response and damage prevention.
- In October 2007, in order to enhance public education, enforcement, and regulation of industry activity in the rapidly developing Barnett Shale play, the TRRC initiated a dialogue with city and county leaders on regulatory oversight issues in the play.[46] Its purpose is to enhance community awareness of the agency's regulatory framework over natural gas drilling and ultimately to increase efficiency and effectiveness of Barnett Shale oversight.

---

[40] http://www.emnrd.state.nm.us/MAIN/documents/PR-OCD.PitRule.5.09.08.pdf
[41] http://www.earthworksaction.org/NMPITRULE.cfm
[42] http://www.santafenewmexican.com/SantaFeNorthernNM/Proposed_pit_regulations_draw_indus
[43] http://www.daily-times.com/ci_11738130?source=most_emailed
[44] http://www.dec.ny.gov/energy/45912.html
[45] http://www.dec.ny.gov/energy/47554.html
[46] http://www.rrc.state.tx.us/pressreleases/2007/101107.php

Previous to this announcement, the TRRC has already taken a number of actions in the Barnett Shale region:

- Reassigned field staff positions from other less active areas of the state to District Offices that cover Barnett Shale activity
- Shifted existing funding and staff positions to enhance inspections and service in the field by reassigning four Austin positions to field staff positions
- Changed Barnett Shale Field oversight to enhance the inspection process as well as responsiveness to emergencies and citizen complaints in the field
- Acknowledging an increase in applications for new saltwater disposal facilities, the TRRC encouraged disposal into the deeper Ellenberger formation. In addition to being below the Barnett Shale reservoir, the Ellenberger formation contains fewer oil and natural gas well penetrations and is located farther away from freshwater zones.
- Developed a website link (http://www.rrc.state.tx.us/barnettshale/index.php) to provide answers to Fort Worth area residents who have questions about the ongoing natural gas exploration and production in their communities.

- In October 2008, the Louisiana Department of Natural Resources (DNR) approved a recommendation that oil and natural gas operators with interest in developing the Haynesville Shale in Northwest Louisiana choose their water sources for use in drilling or hydraulic fracture stimulation operations wisely. They recommended that if ground water must be used for drilling or hydraulic fracture stimulation purposes, the Red River Alluvial aquifer be utilized for these purposes, where feasible. Moreover, they encourage oil and natural gas operators to use the available surface water resources or other acceptable alternative water sources in Northwest Louisiana, where practical and feasible.[47] A month earlier, the DNR issued a notification reemphasizing state requirements associated with water supply wells used solely for supporting drilling and fracturing operations.[48]
- In July 2005, the Ohio Department of Natural Resources (DNR), Division of Mineral Resources Management issued new rules specific to "urban" wells - wells located in municipalities or townships with a population exceeding 5,000. The rules were the result of Ohio House Bill 278, which delegated exclusive authority for the regulation of oil and natural gas wells to the Ohio DNR. Rules for drilling in rural areas remained largely unchanged. The rules were developed by an advisory council of several stakeholders, including the Ohio Municipal League, the Ohio Township Association, the County Commissioners Association, the Ohio Environmental Council, and oil and natural gas producers, and reflected the findings from a series of public hearings and written submissions from a broad base of interested parties. The basic areas covered in the rules are: safety concerning the drilling or operation of a well; protection of the public and private water supply; location of surface facilities of a well; fencing and screening of surface facilities of a well; containment and disposal of drilling and production wastes; and construction of access roads for purposes of the drilling and operation of a well.[49]
- As a result of the increased oil and natural gas activity, where natural gas production has almost doubled over the last three years, the Arkansas Oil and Gas Commission has amended 84 pages of rules, amended their statutes to increase civil penalties and expand enforcement authorities, and has received budget and staff increases to respond to the

[47] http://dnr.louisiana.gov/sec/execdiv/pubinfo/newsr/2008/1016con-gwater-advisory.ssi
[48] http://dnr.louisiana.gov/haynesvilleshale/JHW-hsmemo-20080821.pdf
[49] http://www.redorbit.com/news/science/176125/new_rules_for_urban_oil_and_gas_drilling_ensure_safety/

increased level of activity in the state, especially that associated with the development of the Fayetteville shale.[50]

- The federal agency responsible for regulating oil and natural gas activity on federal lands periodically improves its program to respond to changing priorities and industry conditions, For example, on May 7, 2007, the Bureau of Land Management (BLM) published final revised regulations governing oil and natural gas activity on the public lands. The revised Order included updates required by the Energy Policy Act, the 1987 Federal Onshore Oil and Gas Leasing Reform Act, legal opinions, court cases, and changes in policy and procedure issued since the Order was last updated in October 1983. This rule encourages operators to use environmental BMPs, which are described by the agency in guidance.[51]

Most states have also established site remediation and well plugging programs to address the nearly 60,000 orphan well sites in the country that are on state plugging lists that need to be remediated, for which no responsible party has been identified or exists. In 2006, over 28,000 wells were plugged and well sites cleaned up by such programs, amounting to nearly $145 million expended for this activity. The sources of funding for these programs vary widely. Some states use general appropriation funds, but many are funded through fees, taxes or voluntary assessments on operators.[52]

A number of states also produce guidance documents to assist operators in identifying and implementing Best Management Practices (BMPs) for their operations. Such states include Illinois,[53] Colorado,[54] Montana,[55] and Pennsylvania.[56] In addition, DOE has funded the development of a guidance document on coal bed natural gas impoundments.[57]

State resources devoted to regulation and oversight of oil and natural gas operations are responsive to changing environmental and industry requirements.

In 1993, a report published jointly by IOGCC and DOE examined the evolution of state regulatory programs for oil and natural gas production in 17 states between the early 1980s to the mid 1990s.[58] The study found that between 1979 and 1991, total state government expenditures for the regulation of oil and natural gas operations in the 17 states examined nearly tripled, with personnel responsible for regulatory activities growing by 70%. Most of this growth occurred between 1979 and 1985; the growth in funding and personnel slowed significantly after the oil price collapse of 1986, when well drilling declined dramatically.[59]

---

[50] http://www.aogc.state.ar.us/OnlineData/Forms/Rules%20and%20Regulations.pdf

[51] http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

[52] Interstate Oil and Gas Conservation Commission, *Protection our Country's Resources: The States' Case – Orphaned Well Plugging Initiative*, 2008 (http://iogcc.myshopify.com/collections/frontpage/products/protecting-our-countrys-resources-the-states-case-orphaned-well-plugging-initiative-2008)

[53] http://www.epa.state.il.us/p2/fact-sheets/bmp-oil-exploration.html,

[54] http://coloradowildlife.org/news/oil-and-gas-rules-sheet.html

[55] http://www.bogc.dnrc.mt.gov/website/mtcbm/pdf/BMPhandbookfinal.pdf

[56] http://www.dep.state.pa.us/dep/deputate/minres/OILGAS/Introduction%20and%20Chapter%201.pdf

[57] http://www.all-llc.com/CBM/impound.htm

[58] ICF Resources Incorporated, *Oil and Gas Exploration and Production Waste Management: A 17-State Study,* report prepared for the U.S. Department of Energy, Office of Fossil Energy and the Interstate Oil and Gas Compact Commission (DOE/FE-61017-H1), June 1993

[59] It should also be noted that these numbers, are specific to the primary agency responsible for regulating oil and gas production operations. Other agencies within a state also have some regulatory over these operations, the budgets and personnel responsible for this oversight may not be reflected in these numbers. This is also generally true for some of the state-specific examples provided.

State expenditures for oil and natural gas regulatory programs, in many states, are increasing in response to increased industry activity:

- For example, in Texas, the fiscal year 2008 (FY08) operating budget for the TRRC, the agency responsible for regulating oil and natural gas operations in the state, spent about $8.1 million on environmental compliance activities, which does not include the approximately $18.2 million the TRRC spent in contracts with third party vendors to plug abandoned wells and remediate abandoned oilfield sites.[60] The TRRC has approximately 145 full-time employees working on environmental compliance activities. For the last three years, the operating budgets for the TRRC to oversee state oil and gas programs were as follows:
  - FY 2006: $ 7.75 million in personnel and $17.8 million in third party contracts.
  - FY 2007: $7.9 million in personnel and $19.1 million in third party contracts.
  - FY 2008: $8.1 million in personnel and $18.2 million in third party contracts.

  Personnel costs are for state agency personnel responsible for ensuring compliance of industry environmental statues, rules, and regulations, and includes personnel in permitting, compliance, field offices, mapping, site remediation, and other offices (legal, information technology, administrative, etc.) The additional money for contracts with third party vendors are associated with efforts to plug abandoned wells and remediate abandoned oilfield sites.

- In Oklahoma, funding for the Oil and Gas Conservation Division of the Oklahoma Corporation Commission has increased approximately 29% between 2006 and 2008, as shown in Table 3. Similarly, funding for the Oklahoma Energy Resource Board's (OERB's) site remediation activities have increased by 38% over the same time period.

Table 3

Environmental Regulatory Budget
Oklahoma Corporation Commission
Oil and Gas Conservation Division

Year	FTE	Operating Budget*	OERB Remediation#	Well Plugging	Federal Funds†
2006	115	$7,334,211	$5,250,000	$2,047,500	$364,782
2007	127	$9,391,421	$6,000,000	$2,000,000	$477,500
2008	126	$9,480,906	$7,250,000	$2,250,000	$543,691

* Including federal grant funds, but excluding well plugging; approximately 75% estimated to be environmental related
# Voluntarily funded by Oklahoma Oil & Gas Producers & Royalty Owners; does not include advertising costs
† UIC, Brownfields, and special projects.

- In California, funding for the Oil, Gas, and Geothermal Resources program in the California Department of Conservation has increased by 23% over the last three fiscal years, with personnel increasing by 5% over the same time period, as shown in Table 4.

[60] Note that these budgetary numbers are just for environmental protection, not the overall budget of the agency. The overall annual budget for the TRRC is about $23 million .

Table 4
Changes in State Resources for Regulation of Oil and Gas Activities and Indicators of Industry Activity

	Personnel	Expenditures ($ Million)
2006-07	118	$18.00
2007-08	123	$19.92
2008-09	124	$22.18
% increase	5%	23%

State appropriations processes generally insure that states have the resources to properly regulate the industry, in most cases much more effectively than the federal government. For example, the annual national budget for the UIC program -- approximately $11 million -- has remained static for many years, even as UIC agencies have been asked to take on additional responsibilities.[61]

Moreover, EPA budgets currently are not up to the task of regulating this activity. For example, in the 5 states that make up EPA Region 6, total program budgets to oversee oil and gas activities sum to approximately $ million, as summarized below:

	(thousand $)	
Arkansas	$2,443	Arkansas Oil and Gas Commission, Operations Budget (FY 2007-2008)
Texas	$7,900	Texas Railroad Commission, estimate of expenditures for regulating environmental compliance activitiew for oil and gas only s
Oklahoma	$9,400	Oklahoma Corporation Commission, Oil and Gas Conservation Division (FY 2007)
Louisiana	$11,247	Department of Natural Resources, Office of Mineral Resources (FY 2007-2008)
New Mexico	$10,174	Oil and Gas Conservation Division, Department of Energy, Minerals, and Natural Resources (FY 2007-2008)
	$41,164	

In contrast, the EPA Region 6 budget to regulate all industries in FY 2007 was on the order of $25 million, as summarized below: [62]

[61] U.S. Government Accountability Office, "Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage As a Key Mitigation Option," prepared the Chairman of the Select Committee on Energy Independence and Global Warming, House of Representatives, GAO-08-1080, September 2008 (http://www.gao.gov/new.items/d081080.pdf)

[62] U.S. Government Accountability Office, EPA's Execution of Its Fiscal year 2007 New Budget Authority for the Enforcement and Compliance Assurance Program in the Regional Offices, GAO-08-1109R, September 26, 2008 (http://www.gao.gov/products/GAO-08-1109R)

EPA Region 6 FY 2007 budget (thousand $)

Environmental program and management	
Civil enforcement	$13,606
Compliance assistance and centers	$2,503
Compliance incentives	$540
Compliance monitoring	$7,744
Subtotal	$24,393
Leaking underground storage tanks	$110
Oil spill response	$182
TOTAL	**$24,685**

Industry is also working to promote best practices.

In a wide variety of cases, the oil and natural gas industry is working collaboratively to educate its members on best practices, and to work together with regulatory agencies and other stakeholders to promote best practices. A few examples of such collaborative efforts are highlighted below:

- Barnett Shale Energy Education Council (BSEEC). BSEEC is a community resource that provides information to the public about natural gas drilling and production in the Barnett Shale region. The goal of BSEEC is to be a source of information and to provide answers to questions regarding the opportunities and issues related to urban drilling in the Barnett Shale. In addition, the BSEEC also works on promoting best practices in operations, community relations and other issues important to the communities they serve.[63] Similarly, a consortium of energy companies formed the Barnett Shale Water Conservation and Management Committee to study the industry's water use in the Barnett Shale and to discuss conservation and water management techniques to help conserve fresh water.
- Appalachian Shale Water Conservation and Management Committee (ASWCMC). ASWCMC is a consortium of energy companies focused on efficient and responsible use of water in drilling, completion, and production operations associated with shale development in the Appalachian Region. The mission of the ASWCMC is to develop best management practices and technical solutions for shale developments in the Basin. The committee works cooperatively with the appropriate regulatory agencies to ensure that water resources are managed in an efficient and environmentally responsible manner. Initial goals of the ASWCMC are to determine current and future water needs, establish water quality specifications for drilling and hydraulic fracturing, and to identify technologies that provide solutions for water management and water conservation.[64]
- Natural Gas STAR Partners. Natural Gas STAR is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt proven, cost-effective technologies and practices that improve operational efficiency and reduce methane emissions. Given that methane is the primary component of natural gas and a potent greenhouse gas, reducing these emissions results in many environmental, economic and operational benefits. Through the Natural Gas STAR Program, participants have identified and shared many technologies and practices that can be implemented to reduce methane emissions from oil and natural gas operations. The Natural Gas STAR Program offers

[63] http://www.bseec.org/
[64] http://www.redorbit.com/news/science/1481546/consortium_of_oil__natural_gas_industry_leaders_form_committee/index.html

technical documents covering a wide range of recommended technologies and practices that have various implementation costs and anticipated payback periods.[65]

- RAPPS Document.[66] The Independent Petroleum Association of America and several other oil and natural gas trade associations and their members published a document entitled *Reasonable and Prudent Practices for Stabilization (RAPPS) at Oil and Natural Gas Exploration and Production Sites* that describes various operating practices and control measures used by oil and natural gas operators to effectively control erosion and sedimentation in storm water runoff from clearing, grading, and excavation operations at exploration and production sites under various conditions of location, climate, and slope. Industry is currently revising the RAPPS document to incorporate more technical based information to better help operators select and implement reasonable and prudent practices to limit sediment runoff.

INDUSTRY AND REGULATORY AGENCY PERFORMANCE RELATIVE TO MAJOR FEDERAL ENVIRONMENTAL STATUTES

All of the recent proposals for regulatory reform made by environmental organizations have been made before, have been assessed based on their merits, and the current legislative and regulatory framework has been established based on that assessment. When the U.S. Congress passed RCRA (1976), SDWA (1974), CWA (1972), CAA (primarily the amendments of 1977), CERCLA (1980), and EPCRA (1986), most of the members of the 111th Congress had not yet been elected to office. Before these were enacted, various versions of these laws were proposed, extensively debated, negotiated, and redrafted. In the end, the way the U.S. oil and gas industry is regulated under these statutes was the result of the legislative process hearing all sides of the issues considered, evaluating the relative costs and benefits of various proposals, and making decisions accordingly. This is the way the legislative process is supposed to work.

However, since various environmental groups recommend overturning most of these laws as they relate to the oil and gas industry, it is necessary to revisit the basis of the original decisions regarding the regulation and treatment of the oil and gas industry and determine whether that basis is still valid today.

This process of revisiting American is discussed in the following paragraphs, organized in terms of the major federal environmental statutes affecting American oil and natural gas producers.

Resource Conservation and Recovery Act (RCRA)

Wastes generated during the exploration, development, and production of crude oil, natural gas, and geothermal energy, including produced water, are categorized as "special wastes" under federal law. In 1978, EPA proposed regulations for managing hazardous waste under Subtitle C of RCRA, and included in these proposed regulations was a deferral of hazardous waste requirements for six categories of waste—which EPA termed “special wastes”—until further study and assessment could be completed to determine their risk to human health and the environment. In addition to oil and gas wastes, other categories of special wastes included cement kiln dust; mining waste; phosphate rock mining, beneficiation, and processing waste; uranium waste; and utility waste (i.e., fossil fuel combustion waste). The logic was that these

---

[65] http://www.epa.gov/gasstar/basic-information/index.html

[66] Horizon Environmental Services, Inc. *Guidance Document: Reasonable and Prudent Practices for Stabilization (RAPPS) of Oil and Gas Construction Sites,* HJN 040027 IM, April 2004 (http://www.ipaa.org/issues/hot_topics/rapps.asp)

wastes typically are generated in large volumes and were believed to possess less risk to human health and the environment than the wastes being identified for regulation as hazardous waste.[67] Medical wastes are also treated similarly under RCRA.[68]

However, even though these wastes are exempt from federal hazardous waste regulations under RCRA's hazardous waste provisions, oil and natural gas exploration and production wastes are still controlled and regulated by disposal rules within the various states. Each state has different rules depending on the topography, geology, hydrology, operations, and legislative history for that state. Regulation of the management of the wastes from oil and natural gas operations has been effectively performed by state agencies for decades.

For example, in Texas, while RCRA was passed in 1976, the state had in place waste reserve pits and waste hauling permits required in 1952, waste manifests and record-keeping systems for commercial disposal implemented by 1972, financial assurance in the form of bonds or letters of credit required for operators by 1969, and naturally occurring radioactive material (NORM) rules governing abandonments and disposal by 1975.

In 1988, EPA issued its *Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes*,[69] which stated that it believed that regulation of oil and natural gas exploration and production wastes under RCRA Subtitle C (as hazardous waste) was not warranted. Instead, EPA implemented a three-pronged strategy to address the issues posed by these wastes by improving federal programs under existing authorities in Subtitle D of RCRA (for non-hazardous wastes), the CAA, and SDWA; working with states to encourage changes and improvements in their state regulations and associated enforcement activities; and working with Congress to develop any additional statutory authorities that may be required. This process has worked well since that determination.

Today, environmental groups propose that wastes associated with oil and natural gas exploration and production be addressed under RCRA's cradle-to-grave hazardous waste provisions. In addition to produced waters and CO_2 (which are described in more detail in the SDWA section below), this would apply to drilling wastes and other wastes produced in association with oil and gas operations. This is despite the fact that, as described above, EPA has determined that these wastes should be exempt from federal hazardous waste regulations.

Based on a 1995 survey by the American Petroleum Institute (API),[70] drilling wastes represent about 0.83% of U.S. exploration and production wastes, and other associated wastes represent about 0.05% of total wastes by volume. Produced water makes up over 99% of the volume of the waste generated from oil and gas operations. Of the 0.05%, one study in Louisiana determined that about 15% would test as RCRA hazardous based on analyses conducted of waste streams in the state.[71]

Drilling wastes contain mud, rock fragments, and cuttings from the wellbore, as well as chemicals added to improve drilling-fluid properties. Drilling fluids are used to control downhole pressure, lubricate the drill bit, condition the drilled formations, provide hydraulic pressure to aid

---

[67] http://www.epa.gov/osw/nonhaz/industrial/special/index.htm

[68] http://www.epa.gov/osw/nonhaz/industrial/medical/index.htm

[69] U.S. Environmental Protection Agency, *Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development and Production Wastes*, July 6, 1988 (53 FR 25466) http://www.epa.gov/epaoswer/other/oil/index.htm

[70] American Petroleum Institute, *1995 Survey of Oil and Gas Exploration and Production Waste Management Practices in the United States*, May 2000

[71] Louisiana Department of Natural Resources, Office of Conservation, Public information database; "Analytical Results, Chemical Constituents of E&P Waste Shipments Disposed at Commercial E&P Waste Facilities in Louisiana, 1997 and 1998"

drilling, and remove cuttings from the wellbore. Drilling fluid is pumped down the drill pipe and circulated back to the surface where the rock cuttings are removed and the drilling fluid is recirculated.

Depending on the specific local geologic and operational challenges faced with drilling, producers may use either water-based or oil-based drilling fluids, and in some cases both, over the course of drilling a well. Drilling fluids typically are stored at the well site in lined reserve pits or closed-loop tank systems, depending upon state requirements and geologic and hydrologic conditions. Used drilling fluids typically are disposed of in injection wells – permitted by state regulatory agencies -- or are reformulated and reused. Cuttings typically are collected and stored in lined pits and may be buried onsite (after dewatering), treated and taken to a land fill, or used in agricultural applications depending upon individual state requirements and geologic and hydrologic conditions. Treated drill cuttings have been used beneficially as fill material; daily cover material at landfills; and aggregate or filler in concrete, brick, or block manufacturing. Construction applications for drill cuttings include use in road pavements, asphalt, and in manufacturing cement.

Other associated wastes produced from oil and natural gas production operations include:

- Oily soil**:** Soil contaminated with oil, usually resulting from equipment leaks and spills.
- Tank bottoms: Heavy hydrocarbons, sand, clay, and mineral scale that deposit in the bottom of oil and gas separators, treating vessels, and crude oil stock tanks.
- Workover fluids: Produced from well control, drilling, or milling operations, and stimulation or cleanup of an oil and gas-bearing formation.
- Produced sand: Sand and other formation solids built up in the wellbore in both producing and injection wells.
- Pit and sump waste: Heavy materials settled on the bottom of pits or sumps used to store production fluids. These materials must be removed.
- Pigging waste: Produced when pipelines are cleaned or "pigged." The waste consists of produced water, condensed water, trace amounts of crude oil, and natural gas liquids. It may contain small amounts of solids such as paraffin, mineral scale, sand, and clay.
- Naturally occurring radioactive material: Occasionally occurs where extraction causes a concentration of naturally occurring radiation beyond normal background levels.

As shown previously in Table 1, all state regulatory agencies have provisions for the management and disposal of these waste streams; most of which have in place since long before the original EPA regulatory determination was made.

Clean Water Act (CWA)

Oil and natural gas development and production operations entail various water uses and discharges. In some instances, produced water is injected back into formations to be used to enhance oil and/or natural gas recovery. Oil and natural gas operations must also manage "produced water" -- water that occurs naturally in the formation and must be disposed of or reused after extraction. This activity is regulated at the state level to ensure the protection of fresh water and drinking water sources. Any produced water that is discharged to a receiving body must be permitted under the CWA National Pollutant Discharge Elimination System (NPDES) permitting process. And if the produced water is reinjected, state regulatory programs require surface casing and secondary cement casing in a continuous string past the deepest freshwater zone.

In managing produced water, operators use a variety of technologies and techniques. Most commonly, gravity is used to separate water from the recovered oil in storage tanks at a production site. The separated produced water is stored in tanks prior to disposal or beneficial reuse. The characteristics of the produced water determine whether it can be discharged into surface water bodies, used for irrigation or other beneficial purposes, or must be treated and/or disposed. The potential for reusing the water largely depends on the salinity and chlorine content of the water, as well as contaminant concentrations, particularly hydrocarbons.

Again, most states had rules in effect to protect water before the passage of the Clean Water Act in 1977. Again using Texas as an example, the state had rules in place for the prevention of oil and saltwater runoff into a state water course in 1953, authorized the use of state funds to plug the first abandoned oil well in 1956, and implemented pollution prevention rules for wells, wastes, and disposal in offshore, estuary zones, and rivers in 1969.

A number of proposals to change various aspects of the CWA are being suggested. Environmental groups have proposed that all oil and natural gas operations require storm water permits, rescinding Section 323 of the Energy Policy Act of 2005. Moreover, EPA is implementing potential new Spill Prevention, Control, and Countermeasure (SPCC) requirements under consideration by EPA to “provide increased clarity,” as well as to better “tailor” requirements to oil and gas industry operations. Finally, EPA is considering possible new federal requirements to address the management of water produced in association with methane production from coal seams, and has implemented a process to survey industry to characterize current practices and determined whether additional controls are necessary.

Storm Water Permits

In 1987, the CWA was amended to provide that oil and natural gas production activities did not have to obtain a NPDES permit for the discharge of uncontaminated storm water. Later, EPA interpreted the CWA provision as applicable only to operating facilities and initiated regulations regarding construction activities under a different section of the Act. Industry challenged this interpretation

On March 10, 2003, EPA issued a decision[72] where the determination of the applicability of the storm water discharge permit requirements on oil and natural gas operations was deferred to March 2005, because EPA concluded that it had not adequately performed economic impact analyses related to this industry sector. An important issue under consideration and subject to some debate at the time was whether site construction and site preparation activities conducted prior to oil and natural gas well drilling was considered to be part of the storm water exemption for oil and natural gas facilities originally included in the CWA.[73]

Section 323 of the Energy Policy Act of 2005 clarified the term “oil and gas exploration, production, processing, or treatment operations or transmission facilities” to mean “all field activities or operations associated with exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities.” This refers to section 402(l)(2) of the CWA which identifies oil and natural gas activities for which the EPA shall not require NPDES permit coverage for uncontaminated storm water discharges. The effect of this statutory change made construction activities at oil and gas sites eligible for the storm water exemption.

However, environmental groups have proposed rescinding Section 323 of the Energy Policy Act of 2005.

[72] Federal Register, Vol. 68, No. 46, pp. 11325-11330, March 10, 2003
[73] http://cfpub.epa.gov/npdes/stormwater/oilgas.cfm

In 2004, as a response to the March 2003 decision, DOE prepared a quantitative assessment of the potential economic impacts of storm water discharge requirements on the American oil and natural gas industry.[74] The economic impacts assessed as they relate to three aspects of oil and natural gas operations included:

- The increased costs that industry could bear to comply with the proposed requirements, including the impacts on "construction" sites associated with drilling, gas gathering, and natural gas and liquids transportation operations.
- The project delays that could result and the impact of these delays on the productivity of the nation's rig fleet, on the delay in revenues received from oil and natural gas production, and from other increased costs attributable to project delays.
- The wells that would not be drilled because of permitting delays associated with the new requirements, the production lost from this foregone drilling, and the economic impacts associated with this lost production

Existing state regulatory requirements generally contain specific provisions intended to address concerns about storm water runoff. For example:

- The Texas Commission on Environmental Quality (TXCEQ) is responsible for administering the state's storm water management program.
- The California State Water Resources Control Board (CASWRCB) is responsible for administering the state's storm water management program. The CASWRCB oversees nine Regional Water Resources Control Boards that develop storm water requirements for their particular regions.
- In Oklahoma, EPA administers the state's National Pollution Discharge Elimination System (NPDES) permits for oil and gas activities and the Oklahoma Department of Environmental Quality (ODEQ) administers NPDES permits for other discharges activities.
- The Pennsylvania Department of Environmental Protection (DEP) is responsible for administering the state's storm water management program.
- The Louisiana Department of Environmental Quality (LDEQ) is responsible for administering the state's storm water program. The LDEQ has established the Louisiana Pollutant Discharge Elimination System (LPDES), which administers NPDES permits to construction sites larger then one acre, many industrial sites, and all designated Municipal Separate Storm Sewer Systems.

State regulatory requirements for controlling storm water runoff within in each state vary, and numerical storm water treatment requirements and water quality parameters for individual streams and rivers may impose additional requirements at the municipal and local level.[75] In most cases, state storm water regulatory programs closely model the federal NPDES program, which requires storm water be treated to the maximum extent practicable. Numeric treatment requirements specific to storm water have often not been established at the state level, but water quality parameters are generally established when the risk of contamination is present on a site-by-site basis.

---

[74] Advanced Resources International, Inc., "Estimated Economic Impacts of Proposed Storm Water Discharge Requirements on the Oil and Natural Gas Industry (Final)," memo to the U.S. Department of Energy/Office of Fossil Energy, dated December 7, 2004 (http://www.fe.doe.gov/programs/oilgas/environment/publications/storm_water_summ120704.pdf)

[75] http://www.stormwaterauthority.org/regulatory_data/state.aspx

In 2004, to even better ensure that oil and natural gas operations properly address concerns associated with storm water runoff, industry produced a guidance document (RAPPS) to compile the various reasonable and prudent operating practices that can be utilized by operators in the oil and natural gas industry to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation associated with oil and natural gas exploration, production processing, treatment, and transmission activities.[76]

Spill Prevention Control and Countermeasure

The federal Spill Prevention, Control, and Countermeasure (SPCC) rule was first promulgated in 1973 and became effective on January 10, 1974.[77] After three attempts to revise the SPCC rule in the 1990s, EPA issued a final rule amending the SPCC regulations in July 2002. The 2002 SPCC rule established requirements for non-transportation-related facilities with total above-ground oil storage capacity (in tanks or other oil-filled containers) greater than 1,320 gallons or with buried oil storage tank capacity greater than 42,000 gallons. The 2002 SPCC rule revisions became effective August 16, 2002, but EPA subsequently amended the rule numerous times since then.[78]

In the 2002 SPCC rule proposal, several relatively minor language changes dramatically altered, from the perspective of industry, the scope of the SPCC requirements. These include:

- The inclusion of the word “use” in Section 112.1(b).
- The change in applicability from “tanks” to “containers” that “use” or store oil and have maximum capacity of 55 gallons or more.
- The change in the term “loading rack” to cover “loading and unloading areas.”
- The inclusion of produced water storage tanks as vessels containing oil.

These changes bring a number of other types of facilities and/or pieces of equipment at oil and natural gas exploration and production facilities under the jurisdiction of the rule, beyond the storage “tanks” originally perceived by industry to be the primary focus.[79] New types of facilities/equipment falling under the rule’s jurisdiction include:

- Produced water treatment facilities and associated tanks which contain relatively small volumes of oil.
- Process vessels such as separators, heater treaters, compressors, pump jacks, etc.
- Flow and gathering lines/ process and facility piping.

---

[76] Horizon Environmental Services, Inc. *Guidance Document: Reasonable and Prudent Practices for Stabilization (RAPPS) of Oil and Gas Construction Sites,* HJN 040027 IM, April 2004 (http://www.ipaa.org/issues/hot_topics/rapps.asp)

[77] *(38FR 34164)*

[78] http://www.epa.gov/oilspill/index.htm

[79] EPA asserts that the 1974 rule was always meant to apply to oil-filled equipment, and that the use of the terms “container” and “use” in the language of the 2002 rule is a clarification of the original intent of the 1974 rule. This is evident from “Appendix C, Summary of Revised SPCC Rule Provisions” in EPA’s *SPCC Guidance for Regional Inspectors* published November 28, 2005. In the discussion of minimum container size in the 2002 rule (section 112.1 (d) (5) EPA states that in the 1974 rule “…all containers, regardless of size, were considered to be subject to SPCC provisions.” Again, in the discussion of oil-filled equipment in the 2002 rule (section 112.2), EPA states that the language in the 2002 rule is a “clarification on the application of the rule to this type of equipment”

- Emergency and temporary containers used in drilling and production operations, such as blowdown tanks, emergency tanks and pits, frac tanks, etc.
- Truck loading areas at oil and gas production facilities.

These requirements are proposed without any documented environmental improvements likely to be achieved.

On December 5, 2008, the Federal Register published EPA's final rule to amend the SPCC rule in order to provide increased clarity, to tailor requirements to particular industry sectors, and to streamline certain requirements for those facility owners or operators subject to the rule, which should result in greater protection to human health and the environment. Several modifications have been offered, including modified requirements for process vessels, flow and gathering lines, and truck loading areas.

On January 29, 2009, in accordance with the January 20, 2009, White House memorandum entitled "Regulatory Review" and the Office of Management and Budget (OMB) memorandum entitled, "Implementation of Memorandum Concerning Regulatory Review," EPA delayed by 60 days the effective date of the final rule, stating that amendments will now become effective on April 4, 2009. On April 1, 2009, EPA again delayed the effective date of the December 5, 2008 “final rule,” in response to public comments and the OMB memorandum. The December 5, 2008, amendments will now become effective on January 14, 2010. In addition to delaying the effective date, EPA is also requesting public comment on whether a further delay of the effective date may be warranted. Comments must be received on or before May 1, 2009. Neither this extension, nor the December 5, 2008, final rule remove any regulatory requirement for owners or operators of facilities in operation before August 16, 2002, to maintain an SPCC Plan in accordance with the SPCC regulations.[80]

Oil and natural gas producing states have long recognized the importance of spill prevention and control. State programs for regulating oil and natural gas operations, including spill prevent and control, are diverse in scope and may involve a single agency, e.g., a Department of Conservation or Department of Environmental Protection, which serves as a lead agency and coordinates with other federal, state, regional or local agencies through a Memorandum of Understanding.[81]

State oil and natural gas programs generally complement - rather than duplicate - the pre-2002 federal SPCC requirements to avoid the waste of precious state (and federal) resources and to avoid the confusion of the regulated industry that often results from such duplication. State oil and natural gas regulatory programs include elements regarding spill reporting, spill prevention, spill response, and spill cleanup. In addition, all state oil and gas programs have performance standards regarding prevention of pollution, including prevention of discharges to water and land, but reflect regional differences in geology, hydrology, climate and industry practices. State oil and gas programs also have regulations regarding dikes around tanks and tank requirements, or have the authority to require secondary containment where necessary to prevent pollution or discharge to water. Many states have very specific programs designed to prevent harmful discharges of produced water and other oilfield wastes or fluids, as well as oil.

---

[80] http://www.epa.gov/OEM/content/spcc/index.htm

[81] See Interstate Oil and Gas Compact Commission, *Summary of State Statutes and Regulations for Oil and Gas Production,* 2007, at http://www.iogcc.state.ok.us; State Review of Oil and Natural Gas Environmental Regulations, Inc. reports at www.strongerinc.org.; PWMIS at http://web.evs.anl.gov/pwmis, and Hochheiser, Bill, ALL Consulting, memorandum to Nancy Johnson, dated 10/7/08, entitled “Review of State Regulations for Spill Prevention at Onshore Production Facilities,” in EPA Docket EPA-HQ-OPA-2007-0584, Document ID EPA-HQ-OPA-2007-0584-0176

Some of these programs are more stringent than federal regulations because they require pre-approval of the containment plans by the state regulator before tanks or facility can be used.

Implementation of 2002 SPCC requirements could duplicate or conflict with existing requirements in individual states, possibly necessitating states to pursue new regulatory initiatives or clarifications to address an issue that poses limited environmental risk.

Coalbed Methane Effluent Limitation Guidelines

Coalbed methane (CBM) production accounts for nearly 10% of the total U.S. natural gas production, and is expanding in multiple basins across the U.S. CBM production generally requires removal of large amounts of water from underground coal seams before CBM can be released. CBM wells typically have a distinctive production cycle characterized by: (1) an early stage when large amounts of water are produced to reduce reservoir pressure, which in turn encourages release of natural gas; (2) a stable stage, when quantities of produced natural gas increase as the quantities of produced water decrease; and (3) a late stage when the amount of natural gas produced declines and water production remains low.

The CWA directs EPA to develop regulations as a part of the NPDES program, called effluent limitation guidelines (ELGs), to limit the amount of pollutants that are discharged to surface waters or to sewage treatment plants. EPA identified CBM sector as a candidate for a detailed study in the final 2006 Effluent Guidelines Program Plan (71 FR 76656; December 21, 2006)[82] EPA's federal ELGs do not currently regulate pollutant discharges from CBM operations explicitly; though a wide variety of state regulations already oversee this activity. For example, federal regulations permit discharges using well established Best Professional Judgment (BPJ) processes to develop discharge limits when no appropriate ELG exists.

Nonetheless, most producing states already regulate discharges of water produced in association with CBM.[83] For example:

- The Alabama Department of Environmental Management (ADEM) originally began issuing NPDES permits that were based on the coal mining ELGs and added other water quality-based limits. Initial permits were based on total dissolved solids (TDS), and discharges were limited to an in-stream TDS concentration of 500 mg/l. As the number of CBM wells increased sharply in the mid to late 1980s, ADEM began to enact more stringent discharge requirements to protect the water quality of the Black Warrior River. Today, the permit is quite detailed and contains numerical limits for pH, iron, manganese, biochemical oxygen demand, oil and grease, and dissolved oxygen; additional monitoring requirements for conductivity, chlorides, and effluent toxicity are included. Dischargers are required to install a diffuser on the end of their discharge pipes and to implement a best management practices plan.
- The Wyoming Department of Environmental Quality (DEQ) issues individual NPDES permits and general NPDES permits for CBM water production. The DEQ has established a baseline set of requirements for all streams, as well as additional stream-specific water-quality-based limits.
- The Colorado Department of Public Health and Environment, Water Quality Division, has set comprehensive limits to achieve agricultural and water quality standards. If discharges are made to particularly sensitive streams, the limits may be much stricter than these. In addition, permittees must do an organic pollutant scan for every tenth discharge point.

[82] http://www.epa.gov/guide/304m/

[83] See, for example, Veil, John A., Argonne National Laboratory, *Regulatory Issues Affecting Management of Produced Water from Coal Bed Methane Wells*, report prepared for the U.S. Department Of Energy Office Of Fossil Energy, under Contract W-31-109-Eng-38, February 2002

Colorado uses the agricultural and wildlife use ELGs as its technology basis, but has elected to use a stricter oil and grease limit than the 35 mg/l limit in these ELGs.

EPA is conducting a study to determine if it would be appropriate to initiate an effluent guidelines rulemaking for the Oil and Gas Extraction Point Source Category (40 CFR 435) to control potential pollutants discharged in CBM produced water. To support this study, EPA is in the process of collecting information from CBM operators. This information collection request (ICR) is intended to collect detailed information from about 400 facilities, with questions about source water characteristics, residuals management techniques, costs, and financial data.[84]

Industry believes that the scope of this request is excessive, and the ELGs for CBM are unnecessary, since they will already duplicate state programs effectively managing the management, treatment, and disposal of water produced in association with CBM through BPJ permits. Producer associations believe that few, if any, environmental benefits will result from adopting separate ELGs for CBM.[85]

Emergency Planning and Community Right-to-Know Act (EPCRA) and the Toxic Release Inventory (TRI)

Environmental groups have proposed the need to require oil and natural gas producers to report to the Toxic Release Inventory (TRI) to provide information to the public regarding chemicals that may pose a risk to the health of local communities. The TRI was created by Congress to obtain information on chemical releases from the manufacturing sector of the economy, where concentrated operations at facilities pose a potential risk if releases occur.[86] Oil and natural gas operations are scattered throughout the country in mostly rural areas and individually are generally believed to not pose much risk. While EPA has the authority to expand the scope of the TRI reporting requirements, to date it has not added oil and natural gas production operations because it has concluded that there is no compelling reason to create a new reporting burden for this industry sector that provides no real additional information.[87]

While perhaps exempt from federal TRI reporting requirements, as described elsewhere in this document, oil and gas natural producers still must file a vast array of reports to state and federal agencies on the products, by-products, wastes and emissions they produce, along with reporting any abnormal releases or spills to the environment. For example, producers must report on the oil, gas, and water they produce, along with the disposition of these produced streams. In addition, they are required to report the volume and disposition of all by-product and waste streams that are reinjected into the subsurface or disposed at commercial disposal facilities. Most states require all spills and abnormal levels of emissions to be reported to state agencies.

The American Petroleum Institute (API) has issued a guidance document to provide oil and natural gas producers with information on reporting releases of hazardous substances and petroleum to water as required under federal law, such as that under CWA, CERCLA and EPCRA. The document covers the reporting of what most in the industry consider "emergency" releases, which are unplanned and typically not covered under a permit issued by a government agency.[88]

---

[84] http://www.epa.gov/guide/304m/2008/cbm-icr-200808.html
[85] Boyd, Danny, "Associations Pan Proposed EPA Survey," *American Oil and Gas Reporter*, June 2008, page 40 (http://www.dannymboyd.com/uploads/AOGR-EPA-CBM.pdf)
[86] H. R. Rep. No. 99-962 at 281 (1986), *reprinted in* 1986 U.S.C.C.A.N. 3276, 3374.
[87] 61 Fed. Reg. 33588, 33592 (June 27, 1996).
[88] http://engineers.ihs.com/document/abstract/WPMYCBAAAAAAAAAA

Finally, many companies are implementing environmental management systems within their companies to monitor various environmental performance measures, and report on their performance annually with a comparable level of rigor and sophistication as that exhibited in their financial reports.[89] Industry organizations are developing guidance on such reporting systems.[90]

Safe Drinking Water Act (SDWA)

Environmental groups propose that the underground injection of materials associated with oil and natural gas production that meet the RCRA definition of hazardous waste meet the standards of Class I injection. This would include water produced in association with oil, natural gas, and coalbed methane. Chemical compositions and environmental impacts of produced water can vary significantly depending on the geologic characteristics of the reservoir producing the water and the separation and treatment technologies used.

A widely used practice for crude oil production involves injecting water into the reservoir to enhance the recovery of oil (e.g., "water flooding"). Water, injected under pressure, pushes the oil toward the recovery or producing well. The recovered fluids (water and oil) are separated; the oil is sent to a tank or pipeline, and the water is either treated and reused or disposed in permitted underground injection control wells. Injection wells are permitted through state oil and natural gas regulatory agencies that have primacy for the federal underground injection control program with regulations that include such requirements as mechanical integrity testing, recordkeeping, reporting, and limits on injection volume and pressure. Water flooding represents by far the majority of the produced water managed by producers. Over 90% of the water produced in association with oil and natural gas production in the U.S. is reinjected, either for enhanced recovery (71%), disposal on site (18%), or disposal off site (3%). [91]

Consistent with the EPA's Regulatory Determination related to the exemption for oil, gas and geothermal exploration, development and production wastes under RCRA,[92] and prior to it, Congress amended the SDWA (in 1980) to provide greater flexibility to states that had operational programs to manage the use of produced water to enhance oil and natural gas recovery. The proposed structure of the SDWA and its subsequent regulations for Class II wells[93] proved so burdensome that states were unwilling to seek primacy under the SDWA to run the federal program. The law was changed to allow states to show that their programs provided comparable levels of protection, rather than meet the specific federal program requirements. Without these changes, industry associations have asserted that enhanced oil recovery operations injecting water would have been crippled.

For example, Texas had freshwater pollution abatement laws protecting groundwater in 1955, permitting standards for injection and disposal wells in 1961, well cement casing requirements

---

[89] http://www.globalreporting.org/Home; http://www.oilandgasreporting.com/downloads/SustainabilityReporting.pdf; and http://www.cdproject.net/

[90] International Petroleum Industry Environmental Conservation Association and American Petroleum Institute, *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting*, April 2005 (http://www.api.org/ehs/performance/industry-vol-report.cfm)

[91] Argonne National Laboratory, *A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane,* report prepared for DOE/NETL, January 2004 (http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=1715)

[92] Environmental Protection Agency, *Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes*, [FRL-3403-9], 53 FR 25447, July 6, 1988

[93] Class II wells are statutorily defined as wells that inject fluids associated with oil and natural gas production. Most of the injected fluid is salt water (brine), which is brought to the surface in the process of producing (extracting) oil and gas. In addition, brine and other fluids (such as CO_2) are injected to enhance (improve) oil and gas production.

for protection of groundwater in 1964, plugging requirements for inactive wells in 1967, and fluid injection controls into oil and gas reservoirs in 1972; all before the SDWA was initially enacted in 1977.

Today, wells used for both the injection of water and CO_2 for enhanced recovery are regulated as Class II wells. By all accounts, these primarily state-based programs have been successful. These EPA-approved state Underground Injection Control (UIC) programs exist to protect underground sources of drinking water (USDWs) from endangerment by setting minimum requirements for injection wells. All injection must be authorized under either general rules or specific permits. Injection well owners and operators may not site, construct, operate, maintain, convert, plug, abandon, or conduct any injection activity that endangers USDWs. The purpose of the UIC requirements is to ensure that injected fluids stay within the well and the intended injection zone, or to mandate that fluids that are directly or indirectly injected into a USDW do not cause a public water system to violate drinking water standards or otherwise adversely affect public health.[94]

The environmental organizations' proposals are of particular concern as they may apply to the injection of carbon dioxide (CO_2). While CO_2 itself is not a hazardous substance, the CO_2 stream may contain low concentrations of other substances (such as mercury) that are hazardous substances, or the constituents of the CO_2 stream could react with groundwater to produce minor amounts of listed hazardous substances such as sulfuric acid. Moreover, water and/or CO_2 produced and injected in association with CO_2-EOR projects could be defined as hazardous, since the combination of water and CO_2 can be corrosive. CO_2 mixed with water forms carbonic acid, which can corrode well materials and piping. Corrosivity; along with ignitability, reactivity, or toxicity; is a characteristic that can define a waste stream or injectant as hazardous.

The U.S. oil and natural gas industry has been successfully injecting CO_2 for 35 years to enhance oil recovery, and is currently effectively regulated by state agencies. CO_2 injection in oil fields is a well-understood process, with its environmental performance demonstrated in over 100 fields in the United States. Today, these fields produce approximately 250,000 barrels per day of incremental American oil.[95] Since 1986, when CO_2-EOR was first used in commercial production, over 1.3 billion barrels of incremental oil have been recovered using this technology. Currently, CO_2 -EOR projects have been attempted, are underway, or are starting up in Texas, California, Louisiana, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania.

As EPA and Congress continue to debate programs that will ultimately regulate the geologic storage of CO_2, producers are safely injecting CO_2 under the oversight of successful regulatory programs established at the state level.[96] Imposing additional requirements under the SDWA or other statutes as they relate to CO_2-EOR operations will only inhibit well-established, safe, and effective regulatory programs that have overseen these operations for many years.

In July 2008, EPA published a proposed rule entitled "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells" for public review and comment.[97] It proposes requirements under the Safe Drinking Water Act (SDWA) for the underground injection CO_2 solely for the purpose of long-term

[94] http://www.epa.gov/safewater/uic/index.html
[95] Moritis, Guntis, "SPECIAL REPORT: More US EOR projects start but EOR production continues decline, *Oil and Gas Journal*, Volume 106 Issue 15 Apr 21, 2008
[96] Grigg, Ried B., *Long-Term CO_2 Storage Using Petroleum Industry Experience,* report prepared for the CO2 Capture Project by the New Mexico Petroleum Recovery Research Center, December 20, 2002
[97] http://www.epa.gov/safewater/uic/wells_sequestration.html

underground storage, or geologic sequestration (GS). EPA believes that while the elements of today's proposal are based on the existing regulatory framework of EPA's UIC Program, modifications are warranted to address the unique nature of CO_2 injection for GS, which include the relative buoyancy of CO_2, its corrosivity in the presence of water, the potential presence of impurities in captured CO_2, its mobility within subsurface formations, and large injection volumes anticipated at full scale deployment.

Hydraulic Fracturing

One major source of water use in crude oil and natural gas development, and one that has been the subject of considerable recent attention, is that associated with a practice called hydraulic fracturing. Some environmental groups propose to subject all hydraulic fracturing of oil and natural gas wells to the requirements of the federal UIC program under SDWA, despite language excluding this in the Energy Policy Act of 2005. On September 29, 2008, Congresswoman Diana DeGette (CO) introduced a bill (H.R. 7231) in the U.S. House of Representatives that would reinstate basic federal standards for hydraulic fracturing under the SDWA and enable EPA to regulate it as underground injection under the SDWA.

Background

Hydraulic fracturing is the method used to stimulate the flow of natural gas (and sometimes oil) from a subsurface formation to the wellbore, and, ultimately, to the surface. Recent new activities in emerging shale gas basins in the U.S., such as the Marcellus shale in Pennsylvania and New York (among other states such as Ohio, West Virginia, and Maryland), the Haynesville shale in primarily in Louisiana, and the Fayetteville shale primarily in Arkansas are resulting in natural gas development in areas of the country not previously accustomed to such operations, causing some anxiety and concern among local residents about the potential environmental implications associated with such development.[98] The practice of hydraulic fracturing is essential to ensuring the economic viability of production from these gas shales.

Process of hydraulic fracturing

The process of hydraulic fracturing involves pumping a mixture of water and sand at high pressure into isolated zones to enhance the natural fractures that exist in the formation. During this process, long, narrow cracks are created to serve as a flow channel for natural gas trapped in the formation. Hydraulic fracturing is used to stimulate production from low permeability formations, such as low permeability gas sands, unmineable coal seams, and gas shales.[99] It is important to note that the process of fracturing a well generally takes less than eight hours, which is relatively short in comparison to the 30-plus years of life characteristic of most gas wells in low permeability formations.

Overview of fracturing operations/current and possible future practices[100]

Hydraulic fracturing has been in widespread, common use for nearly 60 years. An estimated 35,000 wells are hydraulically fractured annually in the U.S., and it is estimated that nearly one million wells have been hydraulically fractured in the U.S. [101] The process has been regulated by the states since its first use, with the principal focus of state regulations to protect ground and

---

[98] See, for example, http://www.triplepundit.com/pages/shale-gas-energ.php

[99] Bolin, David E., Deputy Director of the State Oil and Gas Board of Alabama, Testimony before the House Committee on Oversight and Government Reform, October 31, 2007

[100] Much of the material in this section based on Arthur, J. Daniel; Brian Bohm, and Mark Layne, "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," paper presented at the Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008

[101] Bolin, David E., Deputy Director of the State Oil and Gas Board of Alabama, Testimony before the House Committee on Oversight and Government Reform, October 31, 2007

surface water resources. Hydraulic fracturing of natural gas and oil wells is a process that is well understood and well regulated by the oil and natural gas producing states.

Moreover, a large proportion of the wells that could potentially be used in the future for CO_2 storage/sequestration; a process many believe is critical for addressing global climate change. For example, EPA's proposed rule for Class VI wells for geologic sequestration[102] discussing Injection Parameter Limitations recognizes that GS wells may need to be fractured to enhance injectivity. In particular, it states the following on page 43510 of the Federal Register:

> "There are some circumstances, however, where fracturing of the injection zone would be acceptable provided the integrity of the confining system remains unaffected. For example, hydraulic fracturing is a process where a fluid is injected under high pressure that exceeds the rock strength, and the fluid opens or enlarges fractures in the rock. EPA recognizes that there may be well completions which require intermittent treatments, including hydraulic fracturing of the injection zone, to improve wellbore injectivity. Such stimulation of the injection zone during a well workover (as defined in 40 CFR 144.86(d)) approved by the Director would be permissible."

Fate and effect of fracturing

Hydraulic fracture treatments are designed to specific conditions of the target formation (thickness, rock fracturing characteristics, reservoir geochemistry, etc.) to optimize the development of a network of fractures. Their design is based on an understanding of the in-situ conditions present in the reservoir. Hydraulic fracturing designs are constantly being refined to optimize fracture networking and to maximize natural gas production, while ensuring that fracture development is confined to the target formation for both horizontal and vertical gas wells. Initial hydraulic fracture treatments for new plays are designed based on past experience and data collected on the specific character of the formation to be fractured. Engineers and geologists evaluate data from geophysical logs and core samples and correlate data from other wells and other formations that may have similar characteristics. Data are often incorporated into one of the many computer models the industry has specifically developed for analysis and design of hydraulic fracturing.

Hydraulic fracture treatments involve sequenced events which can require thousands or millions of barrels of water-based fracturing fluids mixed with proppant materials such as sand to be pumped in a controlled and monitored manner into the target formation above fracture pressure. Fracturing fluids include a variety of additive components, each with an engineered purpose to facilitate the production of natural gas. Data collection related to fracturing includes coring and core analysis, geophysical logging, reservoir characteristics research, correlation to other wells/stimulations, fracture pressure analysis and other research.

A key to successful hydraulic fracturing is ensuring the fractures created during the stimulation remain in the target zone. Having the fractures extend outside of the productive target zone is not cost effective for the operator because it results in added cost to the fracture job directly, from additional fracturing fluids and proppant, and can lead to adverse affects on the productivity of the well being treated and/or other nearby wells.

Figure 3 is a pie chart showing a relational breakdown of the volumes of various materials and additives used in a hypothetical 2,500,000 gallon fracture treatment, which would be a similar

[102] Federal Register, Vol. 73, No. 144, July 25, 2008

size to a Marcellus Shale horizontal well treatment.[103] As shown, water is the primary component, making up most of the volume of materials used in fracturing operations. In fact, water and sand generally make up 99.5% of the total volume of fracturing fluids used.

Table 5 provides a summary of the additives used in hydraulic fracturing, their main compounds, and some of the other common uses for the main compounds of the additives in day-to-day life. This shows that while there are a variety of different additives that can and are used in fracturing fluids, these additives are items that people encounter in their daily lives.

Because the make-up of each fracturing fluid varies to meet specific needs for a given situation, it is not possible to provide a single amount or volume present of each additive. However, based on the volume of water that is used in making a fracturing fluid as seen in Figure 3, the concentration of these additives is diluted considerably when considered on an overall volumetric basis. Service companies are also working to develop even more environmentally friendly fluids, including the use of hydrochloric acids which more easily break down into simple salts.

Hydraulic fracturing stimulations are monitored continuously by operators and the service companies to evaluate and document the events of the hydraulic fracturing treatments. This includes monitoring every aspect of the process from the wellhead and downhole pressures, to pumping rates, density of the fracturing fluid slurry, tracking the volumes for each additive, tracking volumes of water, and ensuring that equipment is functioning properly.

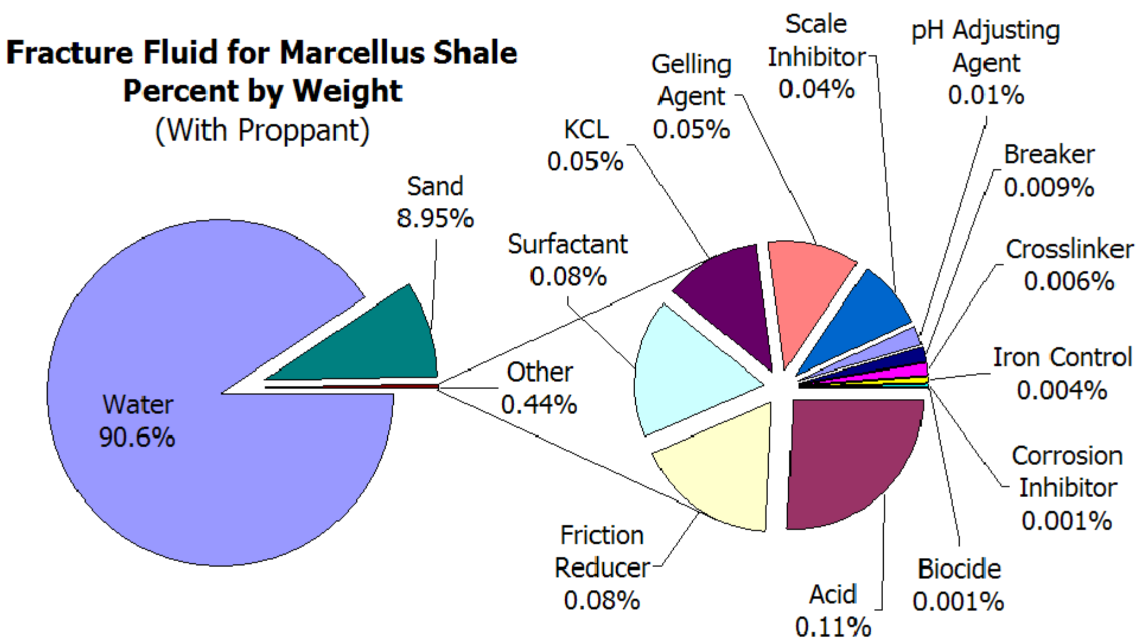
After the target zone in the well has been fractured, it is "shut in" for a short period of time, and the fracturing fluid and sand remain contained inside the well and the fractures are allowed to stabilize. After a short period, the fracturing fluid that was pumped into the well is allowed to flow back out and be reclaimed or treated and disposed.

The initial flow of this flow back from the well is a mixture of natural gas, oil and the fracturing fluid. The separator processes this fluid and separates as much clean, dry natural gas from this mix as possible. The natural gas is piped to a sales line, any oil is piped to a storage tank for future sale, and the water and sand are collected and managed under regulation in an environmentally sound manner. During flow back, generally 40 to 60% of this water is flowed back fairly immediately, though this is not always the case. This water is either sent to a treatment plant to be filtered and treated, stored in tanks and re-used at other locations or disposed in permitted UIC wells. Most of the remainder of the fluid originally pumped into the formation is produced back with the oil and/or gas over time.

[103] Arthur, J. Daniel; Brian Bohm, and Mark Layne, "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," paper presented at the Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008

Figure 3

Fracture Fluid Composition



Source: Arthur, J. Daniel, Brian Bohm, Bobbi Jo Coughlin, and Mark Layne, ALL Consulting, "Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs," presented at the International Petroleum & Biofuels Environmental Conference, Albuquerque, NM, November 11-13, 2008

Table 5
Fracturing Fluid Additives, Main Compounds and Common Uses

Additive Type	Main Compound	Common Use of Main Compound
Acid	Hydrochloric acid or muriatic acid	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Cold sterilant in health care industry
Breaker	Sodium Chloride	Food preservative
Corrosion inhibitor	N,n-dimethyl formamide	Used as a crystallization medium in Pharmaceutical Industry
Friction Reducer	Petroleum distillate	Cosmetics including hair, make-up, nail and skin products
Gel	Guar gum or hydroxyethyl cellulose	Thickener used in cosmetics, sauces and salad dressings.
Iron Control	2-hydroxy-1,2,3-propanetr icaboxylic acid	Citric Acid it is used to remove lime deposits Lemon Juice ~7% Citric Acid
Proppant	Silica, quartz sand	Play sand
Scale inhibitor	Ethylene glycol	Automotive antifreeze and de-icing agent
Surfactant	Wide variety of both anionic and cationic types	Household detergents, fabric softeners, shampoos, laxatives,
KCl	Potassium chloride	Food preservative, low sodium table salt
pH Adjusting Agent	Sodium hydroxide	Paint stripper, soap, water softeners
Crosslinker	Typically a metallic salt	Hair coloring, fertilizer, paints, detergents

Source: Arthur, J. Daniel; Brian Bohm, and Mark Layne, “Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale,” paper presented at the Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008

Comparison of the estimated depth of the target zone and the base of treatable water data demonstrates that in almost all cases gas shale development is estimated to occur several thousand feet below treatable water zones. For example, in the Marcellus shale there can be as much as 7,000 feet (1.3 miles) between the formation targeted for production and the deepest USDW.

In addition to the natural protection of drinking water provided by the distance between producing formations and drinking water, there are protection factors built into state well completion procedures. These procedures apply to all wells, including wells that are hydraulically fractured. These casing and cementing programs are designed to ensure that drilling and construction of a natural gas well protects ground water. This includes primary and secondary casing throughout all freshwater zones, additional surface casing and production string casing throughout the entirety of the well. All of these measures ensure protection from fracturing and groundwater.

Typically, operators must submit detailed plans to state regulatory agencies for casing and cementing for proposed well completions when they file an Application for Permit to Drill (APD). This generally includes the size, weight, and pressure rating of each type of steel casing that will be installed, and details pertaining to how steel casings are cemented into place to further prevent unintended flow of injected or produced fluids from occurring outside of the casing string.

Water Use in Hydraulic Fracturing

Fracturing can require a large amount of water, ranging from as little as 500,000 gallons per fracture treatment to as much as to 6,000,000 gallons to fracture a typical horizontal well, depending on a number of variables.(To provide some perspective, depending on location, rainfall, and water management practices, a golf course can use from 300,000 to over 500,000 gallons of water every day.[104]) The water comes from streams, lakes, ponds and is occasionally purchased directly from municipal water supplies. The water is then trucked to the well site and stored in tanks or in a temporary, plastic lined pond commonly referred to as a pit.

However, it is important to note that the water use efficiency, in general, for natural gas production is the highest of all potential sources of energy. Researchers at the Virginia Water Resources Research Center based at Virginia Tech University analyzed 11 types of energy sources, including coal, fuel ethanol, natural gas, and oil.[105] They based their calculations on available governmental reports by using a standard measurement unit -- gallons of water per British Thermal Unit (BTU). According to the study, the most water-efficient energy sources are natural gas and synthetic fuels produced by coal gasification. The least water-efficient energy sources are fuel ethanol and biodiesel (Table 6).

Moreover, even at high levels of natural gas development, the water use requirements for hydraulic fracturing are quite small compared to other demands on regional water supplies. The major water use survey conducted by the U.S. Geological Survey was conducted in 2000.[106] Table 7 summarizes the total water withdrawals by water-use category in 2000 for some of the states with anticipated significant levels of shale gas development potential.

---

[104]See, for example, http://hillcountrywater.org/GolfCourse.htm and http://www.sptimes.com/News/061701/Hernando/Increased_water_use_i.shtml

[105] http://aquadoc.typepad.com/waterwired/2008/04/virginia-tech-s.html

[106] Hutson, Susan S., Nancy L. Barber, Joan F. Kenny, Kristin S. Linsey, Deborah S. Lumia, and Molly A. Maupin, *Estimated Use Of Water in the United States in 2000*, U.S. Geological Survey Circular 1268, 2004 (http://pubs.usgs.gov/circ/2004/circ1268/#abstract)

Estimates of the potential water requirements for sustaining hydraulic fracturing can be compared to these water use requirements. In this characterization, high-side estimates of the water use requirements for hydraulic fracturing were developed by assuming ten times the number of wells is drilled in these shale gas states over what was drilled in 2006, as reported by IPAA.[107] The characterization also assumes, on the high-side, that all of these wells are hydraulically fractured, and that every well requires 6,000,000 gallons of water for its fracture treatment.

As shown in Table 8, in all of the shale gas states considered, the water use requirements for hydraulic fracturing represent a relatively small proportion of the water use in the state. This is true even using these high side assumptions for the number of wells that are drilled and fractured, and the amount of water required for fracture stimulations.

Overview of current state regulatory requirements for hydraulic fracturing

At both the federal and state level, all of the laws, regulations, and permits that apply to oil and natural gas exploration and production activities also apply to hydraulic fracturing. These include all laws and regulations related to well design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety.

The regulation of hydraulic fracturing is one part of overall state agency responsibility to ensure that all oil and natural gas development and production operations do not adversely impact the environment and public health. States require developers to obtain a permit before drilling and operating a natural gas well. If the well is to be fractured, information about the fracturing program may be included in the application. Agency staff members review the application for compliance with regulations and to assure adequate environmental safeguards, and if necessary, perform a site inspection before permit approval. Most states require notice to affected landowners and/or the public and provide the opportunity for objections to drilling permits. Any protestations are then investigated by the agencies for evidence of possible adverse impacts from drilling. Most states have implemented safeguards even beyond these: most require operators to post a bond or other financial security when obtaining a drilling permit.

In fact, many states have assumed primacy from the EPA for regulating Class II wells under the federal UIC program. These states also have programs already in place to regulate hydraulic fracturing operations. However, if environmental groups' proposals to subject all hydraulic fracturing of oil and natural gas wells to the requirements of the federal UIC program under SDWA, where states have already have primacy, this would mandate that primacy decision would have to undergo a new review. EPA would have to create a regulatory structure against which it would judge primacy. Past experience in Alabama suggests that EPA could produce a standard essentially requiring the use of drinking water for fracturing. In some cases such a result may make sense, but state programs have successfully managed hydraulic fracturing without such specific mandates. Driving a federal structure that could jeopardize effective state regulation requires more justification of environmental risk than has been identified.

Thus, the process of hydraulic fracturing is subject to a rigorous and well established process, developed in accordance to the geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics unique to each state.

---

[107] Independent Petroleum Association in America, *Oil and Gas Producing Industry in Your State (2007-2008),* February 2009 (http://www.ipaa.org/reports/econreports/2007-2008IPAAOPI.pdf)

Table 6
Water Use Efficiency of Various Energy Production Technologies and Fuel Sources

Fuel source	Low range efficiency (gallons/million BTU)	High range efficiency (gallons/million BTU)	Sources
Natural gas	3	N/A	*USDOE 2006; Gleick 1994; EIA 2006a; EIA, 2006b
Synfuel - Coal gasification	11	26	USDOE 2006; Gleick 1994; EIA 2007b
Tar sands	15	38	USDOE 2006; Gleick 1994
Oil shale	20	50	USDOE 2006
Synfuel - Fisher Tropsch	41	60	USDOE 2006
Coal	41	164	*USDOE 2006; Gleick 1994; EIA 2006a; EIA 2007c
Hydrogen	143	243	USDOE 2006
Liquid natural gas	145	N/A	*USDOE 2006; EIA 2005b; EIA 2007a
Petroleum/Oil-electric sector	1,200	2,420	*USDOE, 2006; Gleick 1994
Fuel ethanol	2,510	29,100	USDOE, 2006; USDA 2004
Biodiesel	14,000	75,000	USDOE, 2006; USDA 2004

Source: http://aquadoc.typepad.com/waterwired/2008/04/virginia-tech-s.html

Table 7
Total Water Withdrawals by Water Use Category for Selected Shale Gas States – 2000 (Million gallons per day)

State	Total	Public Supply	Domestic	Irrigation	Livestock	Aquaculture	Industrial	Mining	Thermoelectric Power
Arkansas	10,900	421	29	7,910	0	198	134	3	2,180
Louisiana	10,400	753	41	1,020	7	243	2,680	0	5,610
New York	12,100	2,570	142	36	0	0	297	0	9,050
Pennsylvania	9,950	1,460	132	14	0	0	1,190	182	6,980
Texas	29,600	4,230	131	8,630	308	0	2,357	724	13,260

Table 8
High-Side Estimated Water Use for Hydraulic Fracturing (HF)-- Based on 10 Times Drilling Levels in 2006

State	Total No. of Gas Wells Drilled in 2006	10 Times 2006 Gas Well Drilling	Water Use for HF(million gallons per year)	Average Water Use for HF(million gallons per day)	Total Water Use for the State (million gallons per day	Fracturing % of Total Withdrawals in 2000
Arkansas	395	3,950	23,700	65	10,900	0.6%
Louisiana	1,002	10,020	60,120	165	10,400	1.6%
New York	131	1,310	7,860	22	12,100	0.2%
Pennsylvania	3,247	32,470	194,820	534	9,950	5.4%
Texas	7,624	76,240	457,440	1,253	29,600	4.2%

Note: Estimate assumes that all the wells in the state were hydraulically fractured, and that each well required the 6 million gallons per fracture (the maximum end of the range reported in the text)

Environmental group case studies

Environmental groups use a number of reported "incidents" to support claims for the need for additional federal oversight for the environmental performance of oil and natural gas operations, especially hydraulic fracturing. However, if evaluated objectively, a review of these incidents shows that none of the alleged incidents were caused by hydraulic fracturing. Moreover, these reviews show that where operators violated existing regulations and/or permit conditions, they were so cited and the impacts mitigated.

Some of these incidents are discussed below.

- Bainbridge incident (Ohio).[108] On December 15, 2007, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) was notified of an explosion at a house in Bainbridge Township, presumably caused from leaking natural gas. While an explosion was reported, apparently neither the house nor any of the furnishings inside suffered any fire or smoke damage.

  As with any investigation, the DMRM examined evidence regarding source(s), migration pathways, and the pressure differentials necessary to move the gas from the source(s) to the affected water supplies. Despite claims that hydraulic fracturing was the cause of this incident, the DMRM concluded that confinement of deep, high-pressure natural gas in the surface-production casing annulus of the OVESC (the operation company) English No. I well caused over-pressurization. The primary cement job on the production casing was deficient, and in violation of OVESC permit. Furthermore, and probably most critically, they concluded that OVESC erred in closing the wellhead valve, rather than temporarily venting or flaring the annular gas prior to completing remedial cementing operations. Finally, they concluded that hydraulic fracturing fluid had never entered local water supplies, including the subject well.

[108] Ohio Department of Natural Resources, Division of Mineral Resources Management, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County*, Ohio, September 1, 2008 (http://www.dnr.state.oh.us/Portals/11/bainbridge/report.pdf)

The conditions that resulted in the over-pressurization at the well were corrected, and DMRM initiated a monitoring program to: 1) identify water wells with detectable natural gas, 2) define the area where water samples would be collected, 3) monitor in-house gas concentrations, and 4) measure the response of water wells to the corrective action. On January 18, 2008, the DMRM announced implementation of new permit conditions through broad areas of northeastern Ohio, designed to address the full range of conditions that can create over-pressurized conditions in the surface-production casing annulus.

EnCana Amos/Walker water well (Colorado).[109] On April 30, 2001, the Colorado Oil and Gas Conservation Commission (COGCC) received a complaint that a water well was believed to have gas and possible fracture fluids leaking into it. COGCC investigated by conducting site inspections, measuring bradenhead pressures, and performing and overseeing water and gas sampling and analysis. COGCC staff performed an assessment to determine if there was any evidence of damage caused by fracturing these wells, and found none. Pressure records collected during frac operations indicate the stimulations were confined to the intended formation interval. They concluded that elevated pressures in two gas wells operated by EnCana led either to the failure of the Wasatch Formation below the surface casing shoe or matrix cross flow in one or more of the wells, and that Williams Fork Formation gas or gas from the deeper portion of the Wasatch Formation migrated into the 225 feet deep water well. EnCana did not concur, and believed, based on extensive testing, that the gas in the water well more likely came from gas that occurs naturally in the Wasatch Formation.

Analytical results from extensive water sampling of nearby water wells demonstrated that no frac fluids were ever found to be present in the ground water. The COGCC thus concluded that fracture fluids never reached the water well. In fact, the chemical from fracture fluids that the water well owner claimed to have been exposed to – 2-butoxyethanol ("2-BE) – is a common ingredient in a variety of household cleaners, such as Windex. No 2-BE was found in any of numerous water well samples taken.

COGCC issued a Notice of Alleged Violation ("NOAV") to EnCana, claiming a failure to prevent the intermingling of the gas and water strata; and failure to prevent the unauthorized discharge of gas. Despite EnCana's disagreement with the COGCC findings, EnCana was assessed a fine of $99,400, and was ordered to continue to monitor the Water Well according to the approved Site Investigation Remediation Work Plan. EnCana was also ordered to provide the households that use the Water Well with domestic and drinking water that meet Colorado drinking water quality standards.

- Cathy Behr. An emergency room nurse in Durango, Colorado, Cathy Behr treated a patient in April, 2008 that allegedly been caught in a fracture fluid spill. Ms. Behr treated this patient for about 10 minutes until the room he was in was secured, and the staff treating him put on protective caps and gowns. A few days later, she says her skin turned yellow, and she became nauseous and was retaining fluid. She was rushed to the hospital, and was found to have a swollen liver, erratic blood counts, and lungs filling with blood. She believes that her run in with fracturing fluids on the patient she treated was the likely cause.

  However, the patient treated has said that before coming to the hospital, he removed all protective clothing he was wearing when the spill occurred, and did not have any frac fluid on him when he entered the hospital. Moreover, this individual was treated for mild nausea and released, without complaining of any other symptoms.[110]

---

109 http://cogcc.state.co.us/orders/orders/1v/298.html

110 Moscou, Jim, "A Toxic Spew? Officials worry about impact of 'fracking' of oil and gas," *Newsweek Web Exclusive*, August 20, 2008 (http://www.newsweek.com/id/154394)

Despite claims to the contrary, a supervisor who accompanied the employee to the hospital provided emergency room staff with a copy of the material safety data sheet (MSDS) for the frac fluid. Ms. Behr's regular physician that treated her never requested the MSDS sheet from or contacted either the energy service company that manufactured the frac fluid.

- Pinedale Anticline water well tests. In testing over 200 industrial water wells, operators on the Pinedale Anticline in Southwest Wyoming detected fewer than ten incidents of well water contamination necessitating remediation, as well as trace detected levels of hydrocarbons in seventy-eight other wells. These issues are the result of errors in water well construction and installation practices, as well as naturally occurring elements. The wells in question were industrial water wells, and were never a threat to the drinking water of Sublette County. Operators believe the "contamination" was caused by poor well and pump construction and installation practices, such as use of pipe dope and siphoning dirty water down a water well, as well as possibly natural conditions already existing in the area. In no way were the contamination and detectable level incidents related to fracturing.

  Also, it is important to note in this context that "contamination" merely indicates that a well contains hydrocarbon components that exceed EPA or state standards. If a well contains "trace" or "detectable" levels, it simply means that a component is present, but does not necessarily exceed applicable water standards. The majority of the "trace" wells had low detections of toluene or other BTEX compounds. Components of BTEX are naturally occurring and can be found in a variety of products ranging from bananas to coffee. The water samples came from inside the casing of the water well and may not be representative of water in the aquifer. The detection levels found in most of the wells were well within applicable standards at 10 to 100 times less than what is considered "contaminated."

The bottom line is that in over 50 years of application, despite these allegations, no evidence of environmental damage from fracturing has been demonstrated. In 2004, EPA conducted a study to assess the potential for contamination of underground sources of drinking water (USDWs) from the injection of hydraulic fracturing fluids by coalbed methane (CBM) wells.[111] EPA concluded that the injection of hydraulic fracturing fluids by CBM wells posed little or no threat to USDWs and additional studies were not justified. Nonetheless, as a precautionary measure, EPA also entered into a Memorandum of Agreement with companies that conduct hydraulic fracturing of CBM wells to eliminate use of diesel fuel in fracturing fluids.[112] This precaution was later embedded in the Energy Policy Act amendments to the SDWA where EPA is allowed to regulate hydraulic fracturing under the UIC program if diesel is used.

Clean Air Act (CAA)

Air emissions from oil and natural gas operations include criteria air pollutants (CAPs), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). Most air emissions from oil and natural gas production operations are generated by stationary and mobile internal combustion engines, gas processing equipment, and other activities. In addition, these operations can produce air emissions through venting and flaring, and from fugitive emissions of methane from equipment and operations, though emissions from such sources have declined significantly through voluntary reduction programs.[113] Oil and natural gas production is included as an area source category for regulation under EPA's Urban Air Toxics Strategy, is subject to New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) for new or modified stationary sources, and is subject to a wide variety

[111] http://www.epa.gov/ogwdw/uic/wells_coalbedmethanestudy.html
[112] http://www.epa.gov/ogwdw/uic/pdfs/moa_uic_hyd-fract.pdf
[113] http://www.epa.gov/gasstar/basic-information/index.html

and large number of state and federal operating permit requirements to limit air pollution. Also, in many states, air emissions are addressed by agencies other than the traditional oil and natural gas regulatory agencies.

Environmental groups propose that EPA require aggregation and additional regulation of the emissions of oil and gas production operation under the National Emission Standards for Hazardous Air Pollutants (NESHAP) program. The NESHAP program establishes controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. In addition, they charge that, in violation of the CAA, EPA has failed to review and update clean air regulations related to oil and natural gas operations:

When Congress passed the 1990 Clean Air Act Amendments, it specifically prohibited aggregation of oil and natural gas production sites under the HAPs title because these sites operate as separate facilities and are frequently under different ownership. Because oil and natural gas operations tend to emit significantly less air pollutants than many other industries, and are smaller operations that are spread over a large area and are typically located in remote areas, state and federal environmental agencies traditionally focused their attention elsewhere. Nonetheless, EPA has taken action to regulate the principle source of concern at production sites – glycol dehydrators and engines. Thus, again according to industry, there is no compelling basis to broaden regulation of air emissions from oil and natural gas operations by requiring emissions from such facilities to be aggregated.[114]

In the western states, the Western Regional Air Partnership (WRAP) has been developing state emissions inventory to try to determine the relative contribution of oil and natural gas production activities relative to other sources.[115] WRAP is a collaborative effort of tribal governments, state governments and various federal agencies to implement the Grand Canyon Visibility Transport Commission's recommendations and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. EPA's regional haze regulations. WRAP recognizes that residents have the most to gain from improved visibility and air quality, and that most solutions are best implemented at the local, state, tribal or regional level, with public participation.

A number of health effects studies have been conducted in Colorado that highlight health concerns associated with the populations of areas seeing an increase in oil and gas production.[116,117,118] While these studies are often cited by environmental groups as evidence of the health effects caused by oil and gas operations, the authors of these studies clearly state that drawing broad conclusions from these studies may be problematic, and more study is needed.

Similarly, a recently released study by SMU professor Al Armendariz contends that natural gas production contributes more to air pollution in North Texas than all the major airports and cars in

---

[114] See, for example, IPAA Testimony to the House Oversight and Government Reform Committee in October 2007 (http://ipaa.org/issues/testimony/IPAATestimony-HouseOversiteGovtReform10-31-2007.pdf)

[115] http://www.wrapair.org/

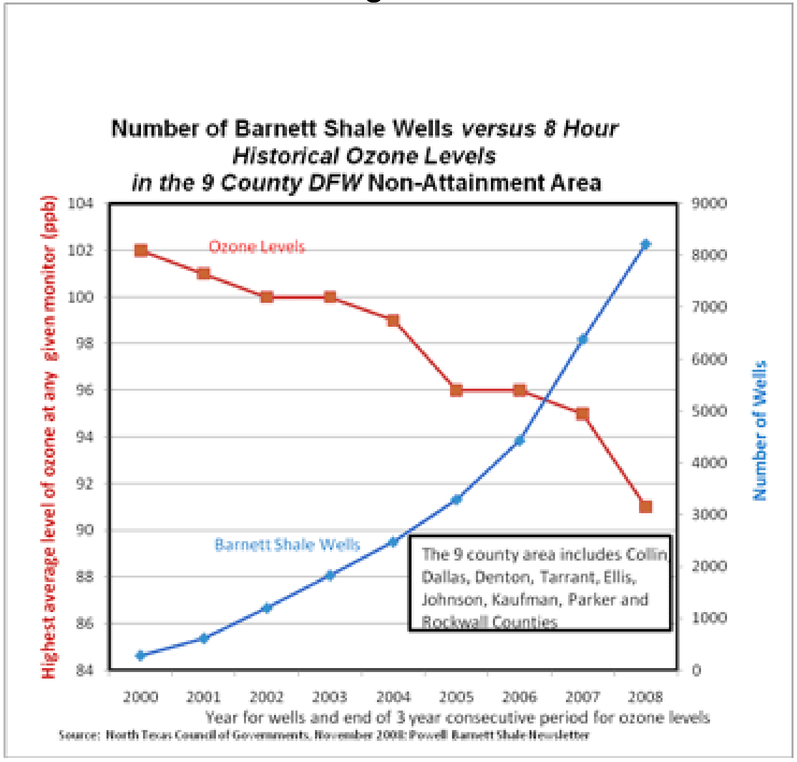
[116] Witter, Roxana, et al., *Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper*, September 15, 1008 (http://docs.nrdc.org/health/hea_08091702.asp)

[117] Colorado Department of Public Health & Environment Disease Control And Environmental Epidemiology Division, *Garfield County Air Toxics Inhalation: Screening Level Human Health Risk Assessment*, September 2007 (http://www.garfield-county.com/Index.aspx?page=1127)

[118] Gable, Eryn, “Energy Development: Colo.’s Western Slope asks BLM to address health effects from drilling,” Land Letter, December 11,2008 (http://www.eenews.net/Landletter/2008/12/11/4/)

the Dallas/Fort Worth (DFW) area combined.[119] In contrast, however, other research demonstrates that Dr. Armendariz's conclusions are based on an inaccurate and flawed interpretation of the facts. [120] As shown in Figure 4, using ozone data from the North Central Texas Council of Governments, as more and more Barnett Shale wells have been drilled, ozone levels in the nine-county DFW area have actually declined. That is not surprising given the emissions reductions in the Barnett Shale region promoted by the North Texas Clean Air Coalition. The data shows that there is no clear relationship between Barnett Shale natural gas production activities and the highest average ozone levels in the DFW area.

Figure 4



The Barnett Shale Energy Education Council's rebuttal of the SMU study asserts that the SMU study is incorrect for several reasons:

- First, most of the natural gas produced in and around the nine-county DFW area is very "dry" gas. This part of the Barnett Shale is "thermally mature," meaning that natural gas wells in this area produce very little associated oil or other liquids. This means most of the wells do not require condensate storage tanks. Indeed, little or no volatile organic compounds (VOC) are emitted from these gas wells.
- Second, the SMU study incorrectly assumes that the wells in the 21-county Barnett Shale area that do produce condensate all have the same amount of VOC emissions per barrel of condensate, regardless of the wells' production pressure or other site-specific variables. From an engineering standpoint, it is wrong to apply one VOC emissions factor to all condensate storage tanks located across 21 counties and expect a reliable estimate. This is

[119] Armendariz, Al, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, report prepared for Ramon Alvarez, Ph.D., Environmental Defense Fund, January 26, 2009 (http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf)
[120] http://www.bseec.org/

because well-producing pressure greatly affects potential VOC emissions. The study also assumes that summertime VOC emissions from condensate storage tanks are 4.8 times higher than those during the rest of the year. This assumption is not even close to reality based on thermodynamic principals.

- Third, wind rose data from the DFW Airport demonstrates that during the summer months the wind blows from the west or northwest only about 4% of the time. Therefore, during the summer months, any VOC emissions actually emitted from condensate production tanks in counties west or northwest of the DFW non-attainment area, and even in western Denton and Parker counties, is blown away from the DFW metroplex the vast majority of the time. The probability of any actual VOC emissions from these western areas significantly impacting high average 8-hour ozone values in the DFW NAA is likely near zero.

The SMU study concludes with the recognition that cost effective control strategies are readily available that can substantially reduce GHG emissions from these oil and natural gas operations, and in some cases, reduce costs for oil and gas operators. These include:

- Use of "green completions" to capture methane and VOC compounds during well completions,
- Phasing in electric motors as an alternative to internal-combustion engines to drive compressors
- Control of VOC emissions from condensate tanks with vapor recovery units
- Replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

In fact, industry is taking a number of steps – including those listed in the SMU study -- to further reduce emissions from their operations, even beyond that mandated by regulatory requirements. Reduction of both intentional and unintentional release of fugitive emissions is being accomplished by some operators in the oil and natural gas industry in appropriate situations using a variety of methods and advances in technology. For example, through the use of vapor recovery units (VRUs), approximately 95% of flared or vented gas can be captured and directed into pipelines or used on site. Leak detection and repair (LDAR) programs use mobile infrared technology to spot previously undetectable levels of escaped gases. Infrared LADR programs save time, money, and protect the environment by allowing maintenance teams to repair minor leaks before they become significant sources of emissions.

Finally, although the amount of fossil fuels consumed in the exploration and production of oil and natural gas is small compared to that of many other sources, reducing emissions from combustion engines is an important step that industry is taking to reduce emissions. This includes operating and maintaining combustion engines according to the manufacturer's instructions, as well as replacing smaller, less-efficient internal combustion engines with lean-burn engines, where appropriate, for lower overall emissions.

On March 5, 2009, EPA proposed NESHAPs for existing stationary reciprocating internal combustion engines that either are located at area sources of HAPs emissions or that have a site rating of less than or equal to 500 brake horsepower and are located at major sources of HAPs emissions. In addition, EPA proposed NESHAPs for existing stationary compression ignition engines greater than 500 brake horsepower that are located at major sources. Finally, EPA proposes to amend the previously promulgated regulations regarding operation of stationary reciprocating internal combustion engines during periods of startup, shutdown and malfunction.[121]

Similarly, the Texas Commission on Environmental Quality implemented a rule that mandates new emissions limits for lean-burn engines at compressor stations in the Dallas-Fort Work Non-attainment area and across 63 counties in East Texas.

Environmental groups have also proposed that hydrogen sulfide (H_2S) be added to the list of HAPs. While H_2S is an acutely toxic gas; it has not been considered a toxic air pollutant in low concentrations. Congress deleted H_2S from the CAA toxic substance list in 1991. H_2S can be produced with oil and natural gas, and regulatory agencies in the states have regulations in place to protect workers, the public, and the environment its acute effects. EPA studied H_2S in the context of oil and gas operations and concluded in 1993 that it should be regulated with regard to accidental releases, but not low level emissions.[122]

FINALS THOUGHTS AND CONCLUSIONS

The U.S. oil and natural gas industry, along with the state agencies that oversee its operations, have always led, are leading today, and will continue to provide a leadership role in ongoing and proactive national efforts in protecting the environment.

The environmental performance of the oil and natural gas industry continues to improve, both from the steady advances in technology and the understanding of the impact of its operations on the environment. Regulatory agencies help encourage this trend by establishing performance standards, rather than strict, prescriptive, “command and control”-type requirements. This has been the approach of many state regulatory agencies for a long time. When oil and natural gas producers talk about regulatory burdens, they generally have concerns with measures that are unnecessarily complicated and involve an unreasonable amount of time-consuming paperwork, without any corresponding improvement in the environment.

State-based regulation of oil and natural gas operations is well established, with a long history. Oil and natural gas producing states were among the first to promote conservation of oil and natural gas and the need to ensure it is produced in harmony with the environment. In fact, most federal environmental laws are predicated on the existence of state regulatory programs. Moreover, most federal statutes allow state regulatory programs to assume primacy for regulating most industries, should they wish to do so. This essential structure is based on the reality that these states have had effective regulatory programs in place for some time, and that the federal government structure is not designed to manage day-to-day regulation of most industries and address state-specific issues. These state programs currently in place adequately and appropriately protect the public and the environment, and help to ensure that American oil and natural gas producers pursue their operations with aggressive and measured approaches to protecting the environment and human health.

Existing state regulatory frameworks currently address environmental risks associated with all aspects of oil and natural gas operations – whether explicitly expressed or not. Moreover, many multi-state and individual state agency efforts are underway to improve regulatory programs for oil and natural gas operations in response to changing environmental concerns, advances in technology, and evolving market conditions. State resources devoted to regulation and

[121] Federal Register, Vol. 74, No. 42, March 5, 2009, pp. 9698-9731
[122] U.S. Environmental Protection Agency. October 1993. *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas.* EPA-453/R-93-045, p.III-35 ()

oversight of oil and natural gas operations are also being modified to respond to changing environmental and industry requirements.

The proposals for regulatory reform made by environmental organizations have been made before, have been assessed based on their merits, and the current legislative and regulatory framework has been established based on that assessment. The federal laws establishing these frameworks were extensively debated and negotiated before legislation was passed. In the end, the way the U.S. oil and natural gas industry was addressed under these statutes was the result of the legislative process hearing all sides of the issues considered, evaluating the relative costs and benefits of various proposals, and making decisions accordingly.

Finally, when various case studies are offered as the justification for the need for increased oversight over American oil and natural gas producers, policy makers need be wary of their interpretation, and investigate allegations themselves. Where clear violations of existing rules and regulations have occurred, the regulatory frameworks in place were quite effective in responding to the problem, identifying the cause and those at fault, and taking corrective action. Another layer of additional federal regulations would have done nothing to avoid the incidents that occurred, and would not likely have resulted in an improved response. Moreover, while the health effects felt by individuals are unquestioned, the causal link is not or is rarely established between oil and natural gas operations in general -- particularly hydraulic fracturing – and these health effects, or the cause of the effects are not related to the activity proposed for more stringent regulation.