Section of Environment, Energy, and Resources
AMERICAN BAR ASSOCIATION

Air Quality Committee Newsletter

A joint newsletter of the Air Quality Committee and the Oil and Gas Committee.

Vol. 21, No. 4 **August 2018**

MESSAGE FROM THE CO-CHAIRS

Elizabeth Hurst, Gary Steinbauer,
Vic Pyle III, and Nora R. Pincus

The chairs of the Air Quality (AQC) and the Oil and Gas (OGC) Committees are pleased to offer this timely joint newsletter focusing exclusively on air quality issues associated with the oil and gas industry.

The five articles in this joint newsletter discuss the issues related to (1) the Trump administration's plans for regulatory rollback by evaluating existing air regulations and making recommendations for modification, repeal, or replacement and regulations and (2) how the states, local governments, and citizens are responding to the administration's pledge to return power to the states in the light of significant cuts to the Environmental Protection Agency's (EPA) budget. James Smith's article discusses how state and federal regulators are identifying enforcement in the oil and gas sector that can provide the biggest impact due to decreased regulatory resources and contains some useful tips on avoiding high-profile enforcement actions. In their article, John Jacus and Will Marshall delve into Colorado's storage tank and vapor control systems guidelines, which were written in response to high-visibility enforcement actions regarding emissions from storage tanks at oil and gas facilities. Georgette Reeves's article provides a technical perspective on the benefits and problems associated with the use of optical gas imaging as a leak detection and repair tool for well sites and compressor stations. Brandon Sousa takes us through the status of regulating methane emissions from oil and gas production. Finally, Dr. Miller discusses the need for economic developers to take a business cycle management approach to the shale economy, which includes identification of legal issues on the front end.

For additional information on air-related issues, you can listen to the AQC 2018 programs, listed below, by going to this SEER link: https://www.americanbar.org/groups/environment_energy_resources/resources/recordings.html.

1. NSR Reform: Past, Present, and Future, April 10, 2018—Program Committee Call
2. Clean Power Plan Rollback—What About Replacement?, January, 23, 2018—Non-CLE Webinar
3. Clean Air Act Advocacy: Tips and Skills, January 9, 2018, CLE Webinar

We also encourage our members to attend the SEER 26th Fall Conference in San Diego from October 17 to 20, 2018.

Our newsletter editors are always ready to entertain article ideas, and we also welcome periodic guest editors to help put together these newsletters. If you wish to propose an article for the Air Quality Committee Newsletters, please contact our committee newsletter vice chairs (Irene A. Hantman at ihantman@verdantlaw.com, David

Continued on page 3.

Air Quality Committee Newsletter
Vol. 21, No. 4, August 2018
David Loring, Irene Hantman,
Rod Johnson, and Taylor Hoverman,
Editors

In this issue:

CALENDAR OF SECTION EVENTS

September 13, 2018
SEER Social- San Francisco Happy Hour
San Francisco, CA

September 27, 2018
Meet EPA Reg. 4 Administrator Trey Glenn
Atlanta, GA
Primary Sponsor: Environmental Law Institute

October 2, 2018
Autonomous Vehicles: The Good, The Bad, & The Ugly
CLE Webinar

October 17-20, 2018
26th Fall Conference
Marriott Marquis San Diego Marina
San Diego, CA

March 25-27, 2019
37th Water Law Conference
Grand Hyatt Denver
Denver, CO

March 27-29, 2019
48th Spring Conference
Grand Hyatt Denver
Denver, CO

For full details, please visit www.ambar.org/EnvironCalendar

Continued from page 1.

Loring at dloring@schiffhardin.com, Rod Johnson at rjohnson@enochkever.com, or Taylor Hoverman at THoverman@afpm.org). If you would like to propose an article for the Oil and Gas Committee Newsletter, please contact our committee co-chairs (Vic Pyle III at vic.pyle@exxonmobil.com or Nora R. Pincus at npincus@parsonsbehle.com).

We would be remiss without recognizing our committee vice chairs. The committees' newsletter vice chairs worked extremely hard pulling this informative joint newsletter together, and the other vice chairs work tirelessly to develop programs and circulate timely and informative information on regulatory and other updates. Thanks for your membership and enjoy this issue!

Elizabeth Hurst *and* **Gary Steinbauer** *are co-chairs of the Air Quality Committee.* **Nora R. Pincus** *and* **Vic Pyle III** *are co-chairs of the Oil and Gas Committee.*

FLARES, VAPOR CONTROL, AND PIGS: ENFORCEMENT TARGETS FOR OIL AND GAS PRODUCTION AND PROCESSING

Jim Smith

Recent enforcement cases provide an indication of where regulators may look to find violations relating to oil and gas production and processing. Proactive companies will take note and ensure compliance before the regulators come for an inspection. If companies discover noncompliance through self-audits, self-reporting and prompt corrective action can minimize the consequences.

EPA's Shrinking Budget and Enforcement Priorities

Since early in the second term of President Obama, and continuing in the Trump administration, the Environmental Protection Agency's (EPA) enforcement budget has been in decline. With smaller federal enforcement budgets, some states have increased their enforcement resources, but it is highly unlikely that state resources will increase enough to make up for the decrease in federal funding.

With decreased resources for environmental enforcement, state and federal regulators have tried to identify areas where enforcement can have the most impact. To some, the "impact" will be based on a sense of potential for environmental harm. However, in other cases, the impact will be based on the ability to extract large civil penalties and other high-profile enforcement consequences.

Focus on Flares

One area that has seen significant attention and large enforcement settlements has been emissions from industrial flares. For example, in October 2017, ExxonMobil settled with EPA and the Louisiana Department of Environmental Quality over allegations of improper operation and inadequate monitoring of flares. In this settlement, ExxonMobil agreed to pay $2.5 million in civil penalties; perform supplemental environmental projects estimated to cost more than $2.5 million; and spend approximately $300 million to install and operate air pollution control and monitoring technology to reduce air emissions at eight petrochemical facilities from 26 industrial flares. In EPA's press release regarding the settlement, EPA alleged that the ExxonMobil flares were not consistently operated at the required combustion efficiency.

In February 2018, the U.S. Department of Justice announced a Clean Air Act settlement with Shell regarding its Norco, Louisiana, facility. The agencies alleged that Shell made major modifications to equipment and processes that transported gases to its flares, without obtaining proper permits and without going through new source review. The settlement requires installation of state-of-the-art monitoring and control technology to ensure flare operation at high-combustion efficiency. Shell estimates these upgrades will cost approximately $10 million.

Flares are used throughout the production and processing of oil and gas. They appear at upstream, midstream, and downstream facilities. These flares generally have combustion efficiency and other requirements, and companies should ensure that their maintenance and testing programs confirm proper operation. Flare issues can lead to large potential penalties. Clean Air Act penalties can approach $100,000 per day per violation and can apply to both operational and record-keeping violations. Thus, flare issues are often seen by regulators as having the potential for significant enforcement impact, especially if the impact is based on large potential penalties.

The Shell settlement also illustrates that modifications to equipment and processes that transport gases to flares may be major modifications that require new source review, even with no changes to the flare or other control technology. Construction or modifications that failed to have required new source review can lead to millions of dollars in potential penalties. To the extent ongoing changes in equipment or processes are contemplated or installed, companies should ensure that they have complied with new source review requirements, or voluntarily report and address the issue if they determine that they neglected to comply.

It appears that serious flare-related mistakes can be made even by sophisticated companies such as Shell and ExxonMobil; companies would do well to focus on flares in their ongoing audits and new source review analyses.

Upstream Vapor Control

Vapor control systems have been an issue at oil and gas processing facilities for decades, but recent enforcement shows an increased emphasis on vapor control at production facilities. Earlier this year, the U.S. Department of Justice and EPA announced a settlement with XTO Energy, an ExxonMobil affiliate, based on allegations that XTO failed to adequately design, operate, and maintain vapor control systems for its storage tanks at well pads. The tanks in question were both produced oil and produced water tanks.

In the settlement, XTO agreed to pay penalties, upgrade its vapor control systems, and complete an environmental mitigation project. The costs of all of these will probably exceed $1 million.

Again, companies should remember that if regulators discover inadequately designed vapor control systems, this can expose the company to significant penalties. Regulators will say that the potential penalties are for each day of operation and for each tank or other structure with an inadequate vapor control system. Thus, the potential penalty can go into the millions, or even tens of millions of dollars, if several structures over a few years have been out of compliance.

Emissions While Using Pigs

Midstream companies have flares and vapor control systems; they also need to evaluate their processes when using pigs during maintenance activities. Affiliates of MarkWest Energy Partners recently settled allegations of illegal air emissions, in which MarkWest agreed to spend an estimated $2.6 million to upgrade facilities, pay $610,000 in penalties, and complete supplemental environmental projects valued at approximately $2.4 million. EPA and the Pennsylvania Department of Environmental Protection alleged that MarkWest failed to apply for required permits and failed to keep proper records of pigging and related venting.

As part of the settlement, MarkWest has agreed to make available a royalty-free license so that others can use MarkWest's proprietary pig ramp technologies, which MarkWest developed during the enforcement investigation.

Stay Current with Industry Standards

Regarding these and other emission control processes, companies need to stay current with industry standards. Many permits have requirements that equipment be properly designed and maintained, but "proper" design and maintenance standards will change as technology develops. Many facilities in this industry are directly subject to the Clean Air Act's "general duty" clause. According to EPA guidance, the general duty clause requires companies to adopt or follow any relevant industry codes, practices, or consensus standards. As a practical matter, companies subject to the general duty clause should expect regulators to assert that updated code provisions or industry standards are legal requirements, even if not specifically referenced in a permit or regulation.

Companies should also review their permits and remember that permit requirements include more than just numerical limits. Most permits have extensive narrative requirements, and compliance with these is mandatory, even if the noncompliance does not result in exceeding a numerical limit. Representatives of environmental groups have indicated that these requirements can be a good source of successful citizen suits because they are often overlooked. In certain circumstances, narrative requirements could require use of updated technologies. With the Clean Air Act's general duty clause and the many narrative requirements in permits, companies should realize that evolving industry standards may not be just suggested good practice; they may be legal requirements.

One developing oil- and gas-related issue is methane emission technology. In November 2017, several leading energy companies, including BP, ExxonMobil, Shell, Statoil, and Total, signed a set of guiding principles on reducing methane emissions across the natural gas value chain. These methane principles include commitments to have plans to monitor and reduce methane emissions, with an emphasis on venting, fugitives, and combustion efficiency. The principles may become industry standards applicable to flares, venting technology, pigs, and other emission-related processes. Industry standards are legal requirements for many involved with oil and gas.

Companies involved in oil and gas production and processing should maintain vigilance regarding flares, vapor control systems, pigging, and other significant maintenance/emission control activities. They must also remember that ongoing developments in control technology, often reflected as industry standards, may tighten their air permit requirements, even with no change in their permit or the regulations.

Jim Smith *is a shareholder with Crain, Caton & James, P.C., in Houston, Texas. His practice includes trial and appellate work involving state and federal environmental programs, as well as compliance counseling and transaction support. First chair trial experience includes civil and criminal jury trials, as well as trials to courts, arbitrators, and administrative agencies, especially TCEQ and EPA. He has argued several important precedent-setting environmental cases before the Texas Supreme Court, several Texas courts of appeals, and the U.S. Court of Appeals for the Fifth Circuit. Jim's undergraduate degree is in chemical engineering from the University of Kansas, and he graduated with honors from the University of Texas School of Law in 1982.*

CYCLICAL CHALLENGES TO ECONOMIC DEVELOPMENT BASED ON THE SHALE ECONOMY

Chad R. Miller, Ph.D.

The boom and bust nature of the oil and gas industry creates challenges for economic developers in shale-rich regions. Economic development organizations are public, nonprofit, or private organizations (e.g., Chambers of Commerce) charged with facilitating public or private investments that create jobs, wealth, improve the tax base, and enhance the quality of life of communities. Traditionally, this has been done through the "three-legged stool" of business attraction, retention, and small business development standing on a foundation of community development. Now these three forms of business development are considered one of the legs with talent development and placemaking being the other two legs.

During the initial economic boom created by hydraulic fracturing, the economic development profession wrestled with how to leverage the growing shale economy. In response, a well-respected economic development blogger, Mark Barbash of Strategic Initiatives, held a series of conversations with economic professionals and developed seven lessons for economic developers.

These lessons include: (1) Incentives are not necessary. The profits are in the sale of oil and gas; therefore, drilling will occur regardless of whether incentives are offered or not. (2) Productivity is increasing because of technological advances that open new shale plays. (3) There is a need for workforce training programs to help local workers. (4) The extraction creates a strain on local services (e.g., roads) and, generally, tax revenues do not match the increased public expenses. (5) There is limited direct job creation from drilling, and many of the jobs are indirect. (6) Economic developers need to diversify the energy supply chain and continue to seek out companies not dependent on the energy industry. (7) Economic developers need to monitor the environmental impact of shale gas drilling.

The economic development program at the University of Southern Mississippi decided to see how these lessons applied to the Tuscaloosa Marine Shale (TMS) region of Mississippi, which was in the early stages of being economically developed. The TMS is a geological formation that covers 28 parishes in central Louisiana and several southwestern Mississippi counties. Much of the region is economically distressed. When the play garnered attention, the Mississippi portion of the TMS was facing 9 percent unemployment and a 28 percent poverty rate. Therefore, a 1997 study based on limited data, which estimated the area could contain seven billion barrels of oil and create an economic boom for the region, raised hope for the economically beleaguered region.

Leasing activities began in earnest in the area only from 2011 to 2012, and extraction proved geologically challenging and expensive. By 2014, over 80 test wells were drilled and techniques were developed to more efficiently produce the Louisiana light sweet crude, but production was less than 12,000 bbl/day. When the price of oil and gas collapsed, hydraulic fracturing dropped to a negligible production rate of 3000 bbl/day. The private sector plans for investment in distribution and infrastructure related to oil and gas were put on hold. The community, which was gearing up for the boom, put much of its planning for a shale economy aside.

Through key informant interviews and examination of secondary data, Southern Mississippi researchers found that the general lessons for economic developers are useful, but specific tactics need to be further developed. There was limited local job creation from drilling. Most of the new jobs were created by suppliers. Incentives for attracting suppliers, rather than drilling, are likely to lead to more local job creation. Workforce training programs are needed to help local workers, and skills transferability needs to be considered.

The strain on local services, even from the limited production in the TMS, was evident in the transportation network. Maintaining the roads was a constant concern in the TMS region, and the projected costs far exceeded the increased revenues. Each well needs hundreds of trucks to bring in equipment, chemicals, water (if piping is not feasible), and frac sand. The water volumes being used in the TMS for hydraulic fracturing were substantially larger than the national average, which had serious implications for road impacts. The farm-to-market Mississippi road network was ill prepared for the strains of the freight volumes. Extensive transportation planning and state support are going to be needed when production ramps back up.

The case of the TMS and other shale regions highlights the need for economic developers to take a business cycle management (BCM) approach to the shale economy. Such an approach requires planning and working now prior to resumption of significant oil and gas activity. For example, economic developers should identify and plan for potential legal issues and inform their community leaders of market projections. These organizations need an organizational culture that supports business cycle-sensitive management activities. Specifically, economic development organizations should prepare for the inevitable down cycle and develop diversity in the economy and supply chain. One aspect of diversifying is skills transferability. Promoting economic development in rural communities is difficult, but a well-planned business cycle approach to leverage the shale economy presents significant opportunities for those communities.

Chad R. Miller, Ph.D., *Associate Professor in the College of Business at the University of Southern Mississippi, is the Graduate Coordinator of the Master of Science of Economic Development program. Chad has a Ph.D. from the Virginia Tech Center for Public Administration & Policy, an MBA from Boston University, and a BA in government from the College of William & Mary.*

THE RETREAT FROM FEDERAL REGULATION OF METHANE, IN FITS AND STARTS

Brandon David Sousa

President Obama's Climate Action Plan sought to reduce the United States' emission of greenhouse gases through many interconnected actions, including the promulgation of numerous regulations finalized near the end of his administration. Republican-led states and industry have initiated suits against most of these rules. Once the Trump administration assumed power, attempts to stay, reconsider, and revise or repeal the rules and regulations began. These deregulatory actions have, in turn, been litigated by Democrat-led states and environmental nonprofits. The result is a snarl of contrary rulemakings and judicial decisions, creating a complicated and confusing regulatory landscape that will likely exist for years to come. While this landscape is subject to frequent change, provided here is a snapshot of the current playing field regarding some of the key methane emissions rules issued under the former Climate Action Plan: the Environmental Protection Agency's (EPA) new source performance standards for the oil and gas industry and the complementary methane waste prevention regulations issued by the Bureau of Land Management (BLM); and EPA's methane standards for landfills.

New Source Performance Standards for the Oil and Gas Industry

Oil and natural gas production and processing accounts for nearly 40 percent of all US methane emissions, and methane is 25 times more potent than CO2 as a heat-trapping gas. Considering these facts, the Obama administration focused its Climate Action Plan on minimizing emissions within the oil and gas industry, promulgating New Source Performance Standards (NSPS) for the industry in 2012. This rule is complete and effective, and the new administration has not proposed reconsideration or revision. The 2012 NSPS established the first federal air quality standards for hydraulically fractured natural gas wells, requiring processes that capture natural gas that would otherwise be lost in extraction. The rule did not, however, directly regulate methane, and in 2016 EPA sought greater emission reductions and specifically targeted methane through an updated NSPS for oil and gas sources. The update does not set any numerical emission limit for methane, but instead requires a number of practices and technologies to reduce emissions, including leak repair and application of Best System of Emission Reduction technologies.

While the 2012 NSPS targeted volatile organic compounds (VOCs) and thus only indirectly regulated methane emissions, the 2016 NSPS Update directly regulates methane for the first time. Direct regulation of methane for new and modified oil and gas sources was a legal trip wire, triggering a requirement under Clean Air Act (CAA) section 111(d) to also regulate existing sources of methane. EPA issued an information collection request accompanying the 2016 NSPS Update, seeking industry input on methane regulations for existing sources.

Upon assuming office, the Trump administration quickly recalled the information collection request, granted an industry petition for reconsideration of several provisions from the 2016 NSPS Update, and proposed a two-year stay of those provisions while the reconsideration process plays out. No final stay of the rule has yet been issued, but any administrative stay would likely be litigated by environmental groups including the Environmental Defense Fund (that organization has already sued EPA and won regarding a briefer, 90-day administrative stay the agency attempted under CAA section 307(d)(7)(B)).

EPA has begun a separate rulemaking designed to roll back and revise the 2016 NSPS Update. EPA sent this "roll-back rule" to the Office of Management and Budget on April 27, 2018, beginning the interagency review process. Because the text of the rule is not yet public, it is uncertain whether the Trump administration will abandon the direct regulation of methane in favor of a "bundle" approach, addressing methane only indirectly through VOCs. However, former EPA Administrator Scott Pruitt has stated publicly that the agency would consider adopting this approach, and it seems likely EPA will make this move to avoid the legal trigger to regulate existing sources.

In the meantime, the 2016 NSPS Update is still effective, and thus EPA is currently regulating methane emissions from new sources directly, triggering the requirement to regulate existing sources. On April 5, 2018, a coalition led by the New York State attorney general sued EPA over this requirement, arguing the agency had "unreasonably delayed" its establishment of guidelines for limiting methane emissions from existing sources in the oil and natural gas sector. *New York v. Pruitt*, No. 1:18-cv-773 (D.D.C. Apr. 5, 2018). While the case's chances for success are likely low considering the agency's active effort to roll back the rule, the litigation brings to a head the debate over EPA's regulatory responsibilities triggered by the 2016 NSPS Update.

Bureau of Land Management's Methane and Waste Prevention Rule

Complementing EPA's NSPS for the oil and gas sector, the BLM issued its Methane and Waste Prevention Rule in late 2016. The Waste Prevention Rule limits the loss through venting, flaring, or leaks of natural gas from oil and gas production on public lands and in Indian country. It applies to both new construction and existing sites, and requires equipment updates and leak repair, waste minimization plans, and stricter natural gas capture processes, among other requirements. While certain provisions of the rule that did not require capital investment, such as waste minimization plans, went into effect on January 17, 2017, most provisions of the rule became mandatory on January 18, 2018.

The Trump administration sought to immediately postpone the effective date of all rule provisions of the Waste Prevention Rule that had not gone into effect before the January 20, 2017, change in administrations by invoking Administrative

Procedure Act section 705, which allows for postponement "[w]hen an agency finds that justice so requires." The states of California and New Mexico, along with 17 conservation and tribal citizens' groups, challenged this postponement and won. *California v. Bureau of Land Mgmt.*, No. 3:17-cv-03804-EDL (N.D. Cal. Oct. 4, 2017). The court ruled that the postponement provisions of APA apply only to rules that are not yet effective, and the effective date of the Waste Prevention Rule was January 17, 2017, with compliance deadlines spaced out over time.

The BLM next attempted to delay implementation through a rulemaking (the "Suspension Rule") that sought to "temporarily suspend or delay certain requirements" by one year based on the BLM's "concerns regarding the statutory authority, cost, complexity, feasibility, and other implications" of the rule. On February 22, 2018, the same court that ruled against the BLM's APA section 705 postponement enjoined the Suspension Rule, making the phase-in provisions of the Waste Prevention Rule immediately effective.

Meanwhile, litigation initiated by Republican states and industry is ongoing in the U.S. District Court of Wyoming, stemming from a challenge to the Waste Prevention Rule that has evolved to take into account the BLM's attempts to alter the regulation through its "Revision Rule." The Revision Rule was proposed on February 22, 2018 (the same day the Suspension Rule was enjoined in the California litigation), and would make substantial changes to the Waste Prevention Rule, rolling back the most costly and environmentally protective provisions. Considering the quickly changing regulatory context, the BLM asked the Wyoming court to stay the litigation and also to stay the Waste Prevention Rule's implementation deadlines. The Wyoming court agreed, staying implementation of the rule and the litigation until the BLM finalizes the Revision Rule, so that "this Court can meaningfully and finally engage in a merits analysis of the issues raised by the parties." *Wyoming v. Bureau of Land Mgmt.*, No. 2:16-cv-00280-SWS (D. Wyo. Apr. 4, 2018). This decision has been appealed to the Tenth Circuit with environmentalists arguing the court granted a de facto preliminary injunction without meeting the legal standards for an injunction.

Thus, while some portions of the Waste Prevention Rule are now in effect, the most important, capital-intensive provisions—including leak detection and repair, measuring and reporting volumes of gas vented or flared, and gas capture percentage requirements—are stayed for the indefinite future.

Landfill Methane Rule

Last, in August 2016, EPA promulgated the "Standards of Performance for Municipal Solid Waste Landfills" to limit emissions of landfill gas (including methane) from new and modified landfills and a companion measure regulating emissions at existing landfills. The rules lower the emissions threshold at which landfills must install controls and impose more strenuous monitoring requirements and a more environmentally protective definition of "landfill gas treatment system."

In October 2016, a coalition of landfill operators filed suit against EPA challenging the rules, but that suit has repeatedly been held in abeyance to accommodate EPA's reconsideration and revision of the rules. *Nat'l Waste & Recycling Ass'n v. EPA*, No. 16-1372 (D.C. Cir. Apr. 3, 2018). EPA has, however, agreed in court filings that the rules are in effect in the meantime. Under the rule for existing landfills, states were required to submit implementation plans by May 2017, and EPA was required to approve or disapprove those plans on a regulatory timeline. EPA has not done so, and on May 31, 2018, seven states led by California filed a lawsuit against EPA pressing for enforcement of the rules.

Conclusion

New forms of regulation take a long time to promulgate and implement, and in the case of methane emissions, the prior administration largely ran out of time. While the Obama administration promulgated several rules designed to curb methane emissions, relatively few such restrictions were successfully implemented and institutionalized. Methane regulations were challenged by industry and opposing states in the courts, delaying or distracting from implementation, and are now subject to repeal and administrative inaction under the Trump administration. While in the coming years we should expect to see litigation and comment from environmental groups and Democrat-led states opposing deregulation, the country will trend, in fits and starts, toward the deregulation of methane.

Brandon David Sousa *is an environmental attorney with Jill Grant & Associates, LLC, in Washington, DC, where his practice focuses on administrative, environmental, and Indian law.*

COLORADO'S STORAGE TANK AND VAPOR CONTROL SYSTEMS GYUDELINES: A SAFE HARBOR FROM AGGRESSIVE CAA ENFORCEMENT IN THE OIL PATCH?

John Jacus and Will Marshall [1]

On May 4, 2018, the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") published first-of-their-kind Storage Tank and Vapor Control Systems Guidelines ("Guidelines")[2] for the oil and gas industry. The Guidelines follow several years of Clean Air Act (CAA) enforcement aimed at the oil and gas industry by state and federal regulators, and were developed by the Division and industry stakeholders over the past two-and-a-half years. The Guidelines describe the technical and practical considerations for design, operation, and maintenance of oil and produced water storage tanks and their associated vapor control systems in Colorado. Specifically, the Guidelines aim to provide oil and gas operators with greater regulatory certainty for storage tank compliance with Colorado's stringent air quality regulations, particularly the "minimize leakage" and "operate without venting" standards in Colorado Air Quality Control Commission (AQCC) Regulation No. 7.[3]

Borne of EPA, North Dakota, and Colorado Enforcement Initiatives

The Guidelines are an outgrowth of U.S. Environmental Protection Agency (EPA), North Dakota, and Colorado enforcement actions in the 2014-to-2018 time period. These enforcement actions alleged inadequate design of vapor control systems that route vapors from storage tanks to emission control devices such as flares and enclosed combustors. These allegations were first made in lengthy and burdensome CAA section 114 information request letters. This pattern of aggressive CAA enforcement became widely known to the oil- and gas-regulated community on April 22, 2015, when EPA and Colorado lodged a consent decree with Noble Energy Inc. ("Noble") in the U.S.

District Court for the District of Colorado.[4] In the associated complaint, EPA and Colorado found that Noble had "emissions of volatile organic compounds (VOC) from condensate storage tanks," primarily due to undersized vapor control systems, in violation of Colorado AQCC's Regulation No. 7 and Colorado's state implementation plan (SIP), among other things.[5] The decree covered 3400 tank batteries and included over 12 million dollars in penalties and mitigation requirements. The decree's injunctive relief provisions required Noble to perform an engineering review of tank system capacities, along with operating and maintenance requirements. The unexpected and novel Noble consent decree illustrated how broadly and aggressively Colorado and EPA could interpret the "minimize leakage" and "operate without venting" general duties of Colorado AQCC Regulation No. 7.

Following the Noble settlement, EPA issued a Compliance Alert in September 2015 that echoed the compliance conclusions in the Noble complaint and consent decree.[6] EPA stated in the Compliance Alert that it had observed emissions from storage tanks at numerous oil and gas production facilities, and warned that operators should evaluate the design of the systems that control these emissions. Most importantly, EPA implied that an engineering design analysis was required prior to operation to ensure proper vapor control system design. Combined with the Noble Consent decree, EPA was signaling its aggressive interpretation of the general duty to minimize emissions "to the maximum extent practicable," and strongly implying that such an interpretation could apply nationwide.

Similar enforcement action was pursued jointly by EPA and the North Dakota Department of Health (NDDH) not long after the Noble consent decree was lodged. After again starting with a CAA section 114 letter alleging various violations of NDDH regulations and the Fort Berthold Indian Reservation federal implementation plan (FIP), EPA and Slawson Energy ("Slawson") ultimately lodged a consent decree in the U.S. District Court for the District of North Dakota on December 1, 2016.[7] The Slawson consent decree mirrored the Noble decree in most respects, also requiring design analyses for Slawson's operations employing storage tanks, as well as maintenance and monitoring. And although NDDH participated in most of the investigations leading up to the consent decree being lodged, it was not a signatory to the Slawson consent decree.

After the Slawson consent decree was lodged, and even while it was still being negotiated, the state of North Dakota became interested in pursuing a more global settlement of alleged storage tank violations with many operators. Although EPA seemed willing to go this route at first, it eventually distanced itself from NDDH's efforts, which culminated in numerous judicially approved state consent decrees. North Dakota's global approach to settlement resulted in less onerous requirements and sanctions than the Noble and Slawson consent decrees, but nevertheless required design analyses for operators that discover emissions from their storage tanks during normal operations. The North Dakota consent decrees and associated complaints also rely on the broad interpretation that storage tank emissions during normal operations necessarily presume an inadequate vapor control system design, in violation of a general duty to route all vapors to an emission control device.[8]

Finally, in October of 2017, EPA and the state of Colorado also settled with PDC Energy, Inc. ("PDC"), for substantially similar alleged violations.[9] PDC's settlement largely tracks the Noble and Slawson consent decrees, but also includes more explicit and specific preventive maintenance and tank design analysis requirements.

Colorado also departed somewhat from its joint enforcement with EPA, and began issuing state-only compliance advisories, many of which have resulted in administrative Compliance Orders on Consent ("COC") being entered with multiple operators.[10] It is believed that Compliance advisory and COC negotiations are ongoing for several additional Colorado operators. These COC settlement negotiations were conducted in parallel to the stakeholder meetings that eventually led to recent publication of the Guidelines.

The noted Colorado COCs also contain allegations similar to the Noble and Slawson consent decrees, namely that operators did not adequately design facilities leading to storage tank emissions, in violation of AQCC Regulation No. 7's "minimize leakage" and "operate without venting" standards. These various COCs also provide for similar injunctive relief regarding the engineering analysis of storage tank systems and extensive operations and maintenance requirements. In addition, companies are given only a limited amount of time in which to find and fix observed storage tank emissions, among other things.

A Better Alternative to Case-by-Case Enforcement?

The above-described enforcement environment led directly to the development and finalization of the Guidelines in Colorado. Beginning in 2016, the Division and the oil and gas industry began a lengthy stakeholder process that started with a common desire to avoid protracted case-by-case enforcement concerning storage tank and vapor control system compliance with air quality regulations. The goals of the effort were threefold: (1) improve performance of vapor control systems on storage tanks, (2) address tank over-pressurization, and (3) articulate the Division's compliance expectations.

The Guidelines address two primary subtopics: (1) well production storage tank and vapor control system facility design and (2) the operation and maintenance of such facilities. The facility design procedures describe how to conduct an engineering design analysis to ensure that vapor control systems have sufficient capacity to handle storage tank emissions. The design analysis "enable[s] a quantitative demonstration of design adequacy."[11]

The design-specific guidelines require two basic steps. First, an operator must estimate a tank system's potential peak instantaneous vapor flow rate ("PPIVFR"). A facility's peak flow rate is evaluated by calculating all emission input points into the vapor collection system. Emission inputs can include flash emissions, working and breathing losses, as well as a catchall "other vapor sources" category. The result of such a peak flow rate calculation is the vapor control system's PPIVFR. Operators use the calculated PPIVFR to compare against the vapor control system's capacity. The Guidelines recommend operators complete facility design analyses for both existing and new facilities.

The operation and maintenance recommendations of the Guidelines address preventive maintenance procedures, critical operating parameters, and predictive analysis recommendations. Preventive maintenance suggestions include both maintenance items, such as cleaning and/or replacing gaskets, and recommended maintenance frequencies. Critical operating parameters are determined from the facility design analysis, and recommended monitoring of storage tanks calls for ongoing verification of each key parameter. Finally, the Guidelines recommend that ongoing record keeping be utilized to assess facility performance and proactively update maintenance or operational procedures at storage tank facilities, when warranted. The Guidelines provide potential examples of records for both preventive maintenance and operating parameters. Note that some operators are required to keep similar records under their consent decrees or COCs, as noted above.

A Pathway to Compliance and a Safe Harbor from Enforcement?

It is important to note that the Guidelines are, as the Division states repeatedly, compliance recommendations only. The Guidelines do not create strict standards or required practices for operators to follow. The Guidelines further encourage operators to apply them to operator-specific scenarios. Perhaps most importantly, the Guidelines state that "the [D]ivision expects that in most instances where emissions from storage tanks are observed, a showing by the owner or operator that it has followed these guidelines will be sufficient to establish *the observed emissions do not constitute a violation* of the 'operate without venting' and 'minimize leakage' requirements of Regulation Number 7."[12] Only time will tell if this Division expectation will be realized for operators that choose to implement the Guidelines for their storage tanks and vapor control systems.

The Noble, Slawson, and PDC consent decrees, along with North Dakota's state consent decrees and Colorado COCs, put on notice the oil and gas industry that storage tank and vapor control system design is essential for demonstrating compliance with applicable regulations. The Guidelines developed by Colorado regulators and operators provide a detailed playbook for improved storage tank environmental performance. The Guidelines are also likely to be heavily relied upon by the Division in specific enforcement actions, i.e., a lack of adherence to the recommendations therein may constitute some evidence of a violation of applicable requirements. Given their unique content and joint authorship by regulators and industry professionals, it is reasonable to anticipate that jurisdictions outside Colorado may rely upon or borrow from the Guidelines in their efforts to better regulate storage tank and vapor control system emissions in the oil and gas industry.

Endnotes

[1] The authors would like to thank Clint Summers for his assistance with this article. Mr. Summers is a third-year student at the University of Tulsa College of Law, and a 2018 summer associate at Davis Graham & Stubbs LLP.

[2] Colorado Dep't of Pub. Health & Env't, Air Pollution Control Div., Storage Tank and Vapor Control Sys. Guidelines: Design, Operation and Maint. (May 4, 2018), *available at* https://drive.google.com/file/d/1A8aUp-ObsL2T3JVzVvsjZ84AeXPbkk0f/view.

[3] Colo. Code Regs. § 1001-9 (2017).

[4] *See* United States v. Noble Energy, Inc., No. 15-cv-00841-RBJ, at *1 (D. Colo. June 2, 2015).

[5] Complaint, United States v. Noble Energy, Inc., No. 1:15-cv-000841 (D. Colo. Apr. 22, 2015).

[6] *Available at* https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf.

[7] Complaint, United States v. Slawson, No. 1:16-cv-00413 (D.N.D. Dec. 1, 2016).

[8] 40 C.F.R. § 49.4165 (2018); *see, e.g.*, Complaint, United States v. XTO Energy Inc., No. 1:18-cv-00060-DLH-CSM (D.N.D. Mar. 23, 2018).

[9] United States v. PDC Energy, Inc., No. 1:17-cv-01552-MSK-MJW (D. Colo. Oct. 31, 2017).

[10] *See, e.g.*, COC, In the Matter of Bonanza Creek Energy Operating Co., No. 2015-096 (Oct. 3, 2017); COC, In the Matter of Extraction Oil & Gas, Inc., No. 2015-082 (Jan. 31, 2018); COC, In the Matter of SRC Energy Inc., No. 2015-081 (Feb. 20, 2018).

[11] Stefanie Rucker, AQCC Storage Tank Guidelines Presentation, *Storage Tank & Vapor Control System Guidelines: Design, Operation and Maintenance* 7 (Apr. 19, 2018).

[12] Guidelines at 8 (emphasis added).

John Jacus *is a partner at Davis Graham & Stubbs LLP and represents clients under all major federal and state environmental laws and regulatory programs. His practice includes environmental litigation, administrative proceedings and representation in complex business transactions. He is experienced in rulemaking and adjudicatory proceedings, permitting, litigation for cost recovery, citizen suits, environmental insurance coverage, and the judicial appeal of adverse agency actions.*

Will Marshall *is an associate at Davis Graham & Stubbs LLP whose practice focuses on complex environmental litigation and enforcement, transactions, permitting and regulatory compliance. His experience includes representing clients in environmental and safety administrative litigation matters, negotiating settlements with enforcement agencies, and advising clients on numerous state and federal environmental regulatory matters affecting industry.*

OPTICAL GAS IMAGING (OGI) FOR OIL AND GAS OPERATIONS: LDAR COMPLIANCE AND BEYOND

Georgette Reeves

Leak detection and repair (LDAR) rules under both state and federal programs allow the use of optical gas imaging (OGI) technology. The technology has benefits over traditional monitoring equipment; however, its use raises several issues for the oil and gas industry including what information is collected, what that information means, and how that information is used.

Current Status of Federal Rules

New Source Performance Standard (NSPS) subpart OOOOa has had a significant impact on the oil and gas industry because it was the first federal rule of its kind to require prescriptive leak detection and repair (LDAR) for oil and natural gas well sites and compressor stations. Although the Environmental Protection Agency (EPA) attempted to delay some of the heavy-hitting requirements of the rule (via a 90-day stay, referred to in a correspondence to petitioners on April 18, 2017, and finalized in the *Federal Register* on May 26, 2017), NSPS OOOOa remains on the books largely intact as it was published in the *Federal Register* on September 18, 2015. On June 12, 2017, EPA proposed a two-year stay of the LDAR provisions for well sites and compressor stations, but the stay has not been acted upon.

On March 12, 2018, EPA amended NSPS OOOOa in two ways: to clarify that leaking components can be repaired during the next scheduled (rather than unplanned or emergency) shutdown; and to allow a delay to the initial survey requirements for certain well sites on the Alaskan North Slope.

This means that, despite the back-and-forth in 2017, the OGI survey requirements (including record keeping, reporting, and repairs) remain in place, with only minor changes that were finalized on March 1, 2018, and have been required since June 3, 2017. The first round of required reports were due October 31, 2017, with subsequent reports due no later than October 31, 2018.

Benefits of OGI Technology

EPA allows the use of OGI technology for compliance with the LDAR requirements for well sites and compressor stations; however, it has yet to be used on a widespread basis to quantify the amount of leaking gas. Under the right conditions, OGI technology can be used to identify leaks from components that otherwise would be considered “difficult-to-monitor” or “unsafe-to-monitor.” However, the concept of what precisely qualifies as “the right conditions” is an evolving issue: as part of the required NSPS OOOOa annual report, EPA requires reporters to include the meteorological conditions during the survey, including maximum wind speed and temperature, as these two elements are critical, per EPA, to determining at what distance an OGI camera can reasonably detect a leaking component.

While the capital cost for a camera is not insignificant (in today’s market, OGI cameras can run anywhere from $60,000 to approximately $100,000), OGI technology allows operators to survey facilities more quickly than using more traditional leak detection technology, therefore requiring fewer personnel hours than what could otherwise be required for a typical leak detection survey (i.e., Method 21).

OGI technology can also be used for other applications to maximize operational efficiency. For example, OGI technology can be used to determine if seals on thief hatches are deteriorated, and can be used to determine if a newly installed component is operating correctly. Routine OGI inspections can assist operators in determining at what frequency certain components may need to be replaced, and can allow them to develop appropriate periodic maintenance (PM) schedules for those components.

Agencies, Nongovernmental Organizations, and OGI Technology

Although OGI technology is expensive, it is widely available for virtually anyone within the United States to purchase. However, while anyone with means can purchase an OGI camera, that person may not be trained to use the camera appropriately; OGI cameras see leaks, but they also see heat signatures as well as gas that is vented from permitted vents. Simply put: OGI technology, in the wrong hands without appropriate training, can generate still images or videos that could look alarming, but may only be stoking unfounded concerns.

Agencies with extensive oil and gas operations in their purview likely have OGI cameras that are used during inspections. For example, consider how the Texas Commission on Environmental Quality (TCEQ) uses this emerging technology: TCEQ inspectors routinely arrive on-site with an OGI camera in hand, and TCEQ also mounts OGI cameras on helicopters in order to survey large areas of land and large numbers of sources. How agencies use the information collected varies by state: the North Dakota Department of Health has requirements in statewide consent decrees and air quality rules that specifically prohibit any leaks to the atmosphere; therefore, information collected via OGI can potentially show noncompliance with those state-level consent decrees or applicable regulations. TCEQ often uses findings from OGI cameras at oil and gas sites as a screening tool to assist facilities in repairing leaks they may have been unaware of. Other states, such as Colorado, Wyoming, Ohio, and Pennsylvania, have robust state-level LDAR programs that allow the use of OGI technology.

One challenge facing industry is that while OGI cameras are effective at finding emissions, the fact that a gas stream is visible using OGI technology may not mean that there is an unauthorized emission requiring repair. NSPS OOOOa differentiates fugitive emissions from venting due to normal operations. The regulation defines a fugitive emission (i.e., “leak”) as “any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21.” The rule goes on to define a “fugitive emissions component” as “any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a, compressors, instruments, and meters.” However, the rule goes on to state that “[d]evices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.”

Therefore, while a stream may be visible within the OGI camera, the stream may come from a device that vents gas as part of its normal operation and is not a fugitive emission. Working with agencies during inspections to delineate between leaks and vents is becoming increasingly critical. These determinations often cannot be made without the express involvement of the operator because they require information about the systems that is only known by persons with deep familiarity with the site’s operation.

Nongovernmental organizations (NGOs) are also using the technology to highlight emissions from the upstream and midstream sectors. One such example is the Oil and Gas Threat map, a collaborative effort between Earthworks, Clean Air Task Force, and FracTracker Alliance. This interactive map includes, among other things, OGI videos of various oil and gas sites throughout the United States. While the videos do show some sites with leaks visible in the OGI camera, the videos also show streams that to the untrained eye look like emissions, but are actually heat signatures from engine exhaust stacks or other interference. Those streams can look very dramatic in the recorded videos even though they are not uncontrolled gas releases (and may be authorized emissions). Additionally, many of the other streams may be legally permitted emissions sources, which are venting at compliant levels. Without detailed context, there is no way to know the difference between unlawful emissions and permitted sources simply from a video. While companies cannot control whether these videos are released to the public, it is becoming increasingly important that someone with knowledge of the technology and how it is used can explain why the captured images may not be evidence of noncompliance.

Beyond 2018: Where OGI May Be Headed

Whether required by a federal rule or employed by a state or other agency, it appears that using OGI technology to find leaks from oil and gas facilities will continue in 2018 and beyond. OGI can be a useful tool in evaluating overall performance and reliability, and can be a powerful tool to develop appropriate periodic maintenance schedules for specific pieces of equipment (such as seals on thief hatches). However, because the technology is widely available, the industry will continue to face the challenges associated with inexperienced camera operators using the technology during inspections or from the fence line, and the possible mischaracterization of streams seen through the camera as leaks.

Georgette Reeves *serves as the Director of the Oil and Gas Business Line for Trinity Consultants, based out of Trinity's Austin office. She has experience in emission quantification and inventories, regulatory analysis and interpretation, greenhouse gas reporting, and is a subject matter expert on New Source Performance Standards (NSPS) for the oil and gas industry including NSPS OOOO and OOOOa.*