Air Regulation Requirements in the Marcellus and Utica Shale Region: Management Approaches and Case Study

Evolving air emissions regulation presents a serious compliance challenge for all oil and gas operators in the United States of America. In Appalachia, a legacy producing region, the rapid development of the Marcellus and Utica shales has led to a rapid expansion of operations across the states of Pennsylvania, West Virginia, and Ohio. Driven by this unprecedented development, increased public pressure, and lawsuits, new regulatory programs are being developed at both the state and federal levels. This article discusses the evolving air regulations impacting operators in the region and how operators can implement an air emissions management system to help them stay compliant.

Compliance Requires New Skills, New Procedures, and New Reporting and Recordkeeping

Introduction

In just over a decade, the Marcellus Shale has gone from simply a source rock for conventional oil and gas fields to a major contributor to the natural gas supply of the United States—large enough to be called a "super giant" gas field (King, 2015). With the addition of the Utica Shale, the northeastern United States is poised to be a major producer for generations.

The Marcellus and Utica shale region underlies the states of Pennsylvania, Ohio,

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and West Virginia. The area is characterized by older, established communities with sporadic legacy oil and gas production. The breadth and scale of the shale operations across the region has led to public concerns about potential impacts to air quality and to additional greenhouse gas (GHG) requirements. Following a similar effort to reduce water impacts, environmental advocacy groups have pressured regulators to control air emissions from oil and gas operations.

In response to public pressure and lawsuits, state and federal regulators undertook a cycle of regulatory reforms targeting the industry. Using the Clean Air Act (CAA) mandates to improve air quality and preserve clean air to accommodate future growth, federal and state regulators are promulgating regulations that require operators to control emissions by obtaining permits, implementing emission reduction strategies, maintaining records to demonstrate compliance, and submitting compliance information to regulators (McCarthy, 2005). In addition, the Obama Administration's commitment to enacting policies on climate change is expected to have significant impacts on oil and gas operators (Ginsburg, 2014).

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The Developing Air Quality Concern

Marcellus Shale gas development and production activities can be a significant source of air pollution (Roy, Adams, & Robinson, 2014). The table in **Exhibit 1** lists typical sources of emissions from various upstream operations. Although each activity on its own is minor, the cumulative impact is a concern at both the local and regional levels. This is particularly true as operators in the basin move to pad drilling, possibly targeting multiple zones. An emission inventory completed by Roy et al. (2014) determined that Marcellus development will lead to a significant increase in nitrogen oxides (NO_x) and volatile organic compound (VOC) emissions in the region. It is projected that in 2020, Marcellus development will contribute 12% (6–18%) of the total NO_x and VOC emissions in the Marcellus region (Roy et al., 2014).

The Evolution of Air Emissions Regulation From Oil and Gas Operations[1]

Prior to the widespread application of hydraulic fracture stimulation to shale formations, operators in the region's oil and gas industry typically installed a single well per location with development and production air emissions in substantially lower amounts than is the case in modern shale operations. Because oil and gas emissions from these single well sites were relatively minor in their amounts, federal air regulations associated with oil and gas operations focused on midstream and processing operations, and the states typically exempted oil and gas operations from air permitting and operating requirements. In addition, there was no structure in place to regulate GHG (i.e., methane) emissions at that time (Seguljic, 2015).

All of this changed with the large-scale adoption of oil and gas production activities using hydraulic fracture stimulation, horizontal drilling, and multiwell drilling pads, which dramatically increased emissions from production operations. A series of events focused attention on upstream oil and gas emissions (Seguljic, 2015).

Exhibit 1. Emissions Sources in Upstream Operations

In a basin covering 95,000 square miles, these activities involve a large number of widely distributed activities, including:

- *Drilling*: A drill rig has 5–7 independent, diesel-powered compression ignition engines, each rated between 500 and 1500 brake horsepower (bhp). These engines are major sources of NOx and PM2.5.
- *Completions*: Hydraulic fracturing (fracking) is performed to stimulate natural gas production after a well bore has been drilled. Typically, 8–10 frac pumps powered by 1000–1500 bhp diesel engines pump large quantities of fluid and sand into the well bore to fracture the formation. These activities generate Methane, NO_x, VOC, and PM2.5.
- *Completion venting*: After a well has been drilled and fractured, the well is vented to remove debris, liquids, and inert gases used to stimulate gas production. This procedure can be a significant source of VOCs, especially for wet-gas wells (gas with significant amounts of higher molecular weight hydrocarbons).
- *Trucks*: Are used to transport drilling and fracturing equipment, water, chemicals, wastewater, and other material to and from a well site. These trucks can generate PM2.5 emissions as they travel unpaved access roads.
- *Wellhead compressors*: Are relatively small (50–250 hp), natural-gas-fired spark-ignited reciprocating internal combustion engines located at the wellhead to raise the pressure of the produced gas to that required in the gathering line. Wellhead compressors emit NO_x, PM2.5, and VOCs.
- *Condensate tanks*: Store higher molecular-weight hydrocarbons (carbon number >5) that are separated on site from the produced gases. Emissions from condensate tanks include VOCs from tank working, breathing, and flashing losses.
- *Pneumatic devices*: Used for a variety of wellhead processes and a source of VOCs and methane. The emissions typically depend on the type and number of devices (e.g., pneumatic-level controllers, valves), the bleed rate of gas from these devices, and the VOC content of the gas (wet or dry).
- *Equipment leaks*: Well pad components and equipment can leak due to lose fittings, cracks, etc. There is a high degree of uncertainty regarding methane leakage rates. Estimates of fugitive emissions vary, ranging from 1 to 7% of total production. Most recent publications indicate a leakage rate of 1 to 2%. In addition, VOC emissions from leaks vary dependent on the natural gas composition.

Sources: Roy, Adams, and Robinson (2014); Bar-Ilan, Parikh, Grant, Shah, and Pollack (2008); Grant, Parker, Bar-Ilan, Kemball-Cook, and Yarwood (2009); Trembath, Luke, Shellenberger, and Nordhaus (2013).

In 2012, the U.S. Environmental Protection Agency (EPA) issued the first regulations to control emissions from oil and gas production operations. In addition, emissions from Marcellus well development and production exceeded states' emission rate exemptions in Ohio and West Virginia, whereas Pennsylvania eliminated permitting exemptions. Furthermore, various court cases enabled the EPA to regulate GHG emissions; oil and gas systems are the second largest stationary source of GHGs[2] (EPA, 2014a).

Federal Regulatory Construct

All current regulations affecting the oil and gas industry stem from the federal Clean Air Act of 1970 and the Clean Air Act Amendments of 1990 (CAAA). These regulations created pollutant categories and source categorization. The CAA defined the role of the states in the regulatory process. The CAAA added toxic/hazardous air pollutants as regulated pollutants.

National Ambient Air Quality Standards

Under the CAA, the EPA is charged with reviewing and setting National Ambient Air Quality Standards (NAAQS) that protect public health. Recently, the EPA proposed lowering the primary and secondary NAAQS ozone standards to a level within the range of 0.065–0.070 parts per million (ppm) and 0.065–0.070 ppm, respectively, by October 2015 (EPA, 2014b). These lowered NAAQS will require the EPA and the states to develop more strict emission controls for sources of VOC and NO_x, such as oil and gas development and production operations.

Operating Requirements

The EPA first regulated the oil and gas industry when it issued a New Source Performance Standard (NSPS) in June of 1985. This standard covered the processing and transmission of oil and natural gas (EPA, 1985). However, it took another 27 years before the EPA regulated the production of natural gas.

In August, 2012, the EPA issued the new emission standard 40 Code of Federal Regulations (CFR) Part 60, Subpart OOOO, for the oil and natural gas industry, which applies to a variety of equipment and operations, Including:

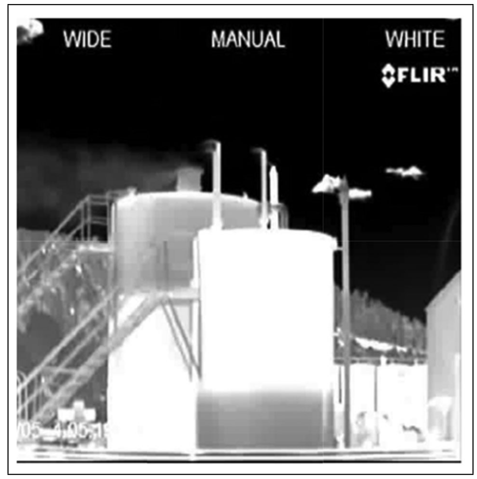
- Each gas wellhead;
- Well completion;
- Centrifugal and reciprocating compressor using wet seals;
- Natural gas driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour that is located between the wellhead and the point of custody transfer to the natural gas transmission;
- Storage vessels (EPA, 2012).

Subpart OOOO subjects impacted equipment or operations conducted, installed, or modified after August 23, 2011, to a variety of notifications, operating requirements, emission limits, maintenance requirements, and recordkeeping and reporting requirements. One of the most significant requirements affects the venting and flaring of natural gas during well completion: From adoption of the rule to January 2015, completion gas had to be combusted (flared). After January 2015, combustion gas must be routed and recovered into collection systems/gas flow lines, etc. (often called green completions).

Addressing VOC Emissions From Equipment

As natural gas production has increased, the EPA has determined that significant sources of methane emissions collectively are loose fittings, hatches that are not properly weighted and sealed, and deteriorated seals. In response, on May 12, 2016, the EPA finalized NSPS Subpart OOOOa, which raised leak detection requirements to the federal level. In particular, new and modified well

Exhibit 2. Emissions Plumes at an Oil and Gas Facility Captured by a FLIR Camera



sites must conduct an initial Leak Detection survey by May 12, 2017, or within 60 days of the startup of production, whichever is later (EPA, 2016). After the first survey, leak monitoring surveys must be conducted twice a year. The leak detection tests must be conducted using optical gas imaging (see **Exhibit 2**); However, "Method 21" (using a portable VOC monitoring instrument, such as an organic vapor analyzer) may be used as an alternative to optical gas imaging. In addition to the Subpart OOOOa requirements, the EPA proposed Control Technology Guidelines (CTGs) (EPA, 2015). The proposed CTGs do not apply any requirements directly to facilities; rather, they provide recommendations for state and local air agencies to consider when they are determining reasonably available control technology for reducing emissions from covered processes and equipment. States may use different technologies and approaches, subject to EPA approval, provided that they achieve the same level of emissions reductions as would be achieved under the CTGs. It is important to note that, as both Pennsylvania and Ohio are designated nonattainment for ozone, it is highly likely the states will utilize the EPA's proposed CTGs to reduce VOC emissions, including:

- *Leaks (fugitive emissions)*: Implement an optical gas imaging, monitoring, and repair program; includes monitoring twice yearly.
- *Pneumatic controllers*: Limit natural gas bleed rate to 6 standard cubic feet per hour or less, with exceptions for operational requirements and safety.
- *Pneumatic pumps*: If there is an existing control device on site, reduce VOC emission from each gas-driven chemical/methanol and diaphragm pump by at least 95%.
- *Storage tanks*: Reduce VOC emissions by 95% at each storage tank with the potential to emit 6 tons or more of VOCs a year.

In conjunction with the Subpart OOOO promulgation, the EPA also revised the glycol dehydrators requirements under subpart HH to include leak detection and repair (LDAR) for large units, and emission controls requirements for small units (with flow rates less than 85,000 standard cubic meters per day or 1 ton benzene emission per year) (EPA, 2012). On May 12, 2016, EPA issued final updates to its NSPS for the oil and gas industry to reduce emissions of GHG—most notably methane—along with smog-forming VOCs from new, modified, and reconstructed sources in the oil and natural gas industry. At natural gas well sites, the updates add new requirements for detecting and repairing leaks, and requirements to limit emissions from pneumatic pumps.

To control NO_x and Hazardous Air Pollutant (HAP) emissions from stationary internal combustion engines (e.g., used to power wellhead compressors), the EPA recently established NSPS and National Emission Standard for Hazardous Air Pollutants (NESHAP) rules, including:

- *40 CFR 60, Subpart IIII (NSPS)*: Subjects stationary compression ignition internal combustion engines manufactured, installed, or reconstructed after July 2006, to notification, emissions limits, certification, and recordkeeping and reporting requirements.
- *40 CFR 60, Subpart JJJJJ (NSPS)*: Subjects stationary spark ignition internal combustion engines manufactured, installed, or reconstructed after July 2007 to notification, emissions limits, certification, and recordkeeping and reporting requirements.
- *40 CFR 63, Subpart ZZZZ (NESHAP)*: Subjects stationary spark and compression ignition internal combustion engines installed prior to July 2006 to emissions limits, maintenance, and recordkeeping and reporting requirements depending on engine size and ignition type.

If engines do not meet emission limits, then controls must be installed and performance testing must be conducted to demonstrate compliance with the noted emission limits.

At natural gas well sites, the updates add new requirements for detecting and repairing leaks, and requirements to limit emissions from pneumatic pumps.

Greenhouse Gases

As a result of Supreme Court rulings in the early 2000s, the EPA was granted the authority to regulate GHGs as a pollutant under the CAA (Supreme Court of the United States, 2006). In November 2010, the EPA promulgated regulations under 40 CFR 98, Subpart W, which required the monitoring and reporting of GHG emissions from petroleum and natural gas systems that emit greater than or equal to 25,000 metric tons of carbon dioxide (CO_2) equivalent per year throughout the entire geologic basin (EPA, 2010). Under the rule, the EPA defined a facility as all petroleum or natural gas equipment on a well pad or associated with a well pad under common ownership or control, including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator, that are located in a single hydrocarbon basin (Russell, 2014). The EPA decided on the basin definitions created by the American Association of Petroleum Geologists (AAPG). For example, most Marcellus production is in the Appalachian Basin (Eastern Overthrust Area), AAPG Basin 160-A, which includes Pennsylvania and West Virginia (Seguljic, Martin, & Stiegel, 2016). Using this approach, a single facility could consist of the collection of hundreds, if not thousands, of individual wells.

Although the EPA has acknowledged that it has no capacity to deal with all of the incoming data from the GHG inventory, the Agency intends to use the data to assist in conducting basic engineering research and a technology program to develop, evaluate, and demonstrate regulatory strategies and technologies to address GHG emissions as described in section 103 of the CAA (EPA, 2013; Russell, 2014).

Since promulgating the initial rule, the EPA proposed revisions to Subpart W, including revising calculation methods and monitoring and data reporting requirements (EPA, undated a). The amendments were quickly followed by proposed revisions in December 2014, which would add reporting of GHG emissions from gathering and boosting systems, completions, and work-over of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines (EPA, undated b). These revisions were adopted in late 2015. Beginning in 2016, most upstream operators will report in both the onshore production and gathering and boosting segments.

The proposed leak detection provisions would be required only for sources reporting under Subpart W that are also subject to Subpart OOOOa. Facilities with a Subpart OOOOa-affected source would calculate and report their GHG emissions by using the data derived from the Subpart OOOOa fugitive emissions requirements, the Subpart W equipment leak survey calculations, and leaker emission factors. For sources reporting under Subpart W that are not subject to Subpart OOOOa (e.g., flares, dehydrators), the proposed leak detection methods could be used voluntarily.

In addition, the White House issued its "Methane Climate Action Plan-Strategy to Cut Methane Emissions" on January 14, 2015, which includes a goal to reduce United States methane emissions by 40–45% from 2012 levels by 2025 (White House, 2015). The plan, highlighted in the table in **Exhibit 3**, states that the bulk of the cuts will be focused on the oil and gas industry pursuant to new regulatory actions that will primarily originate with the EPA and also from the Bureau of Land Management, Department of Energy, and other federal agencies. In line with this policy initiative, the EPA has followed its 2015 major Subpart W rule revisions by releasing a 2016 proposed revision package.

State Regulatory Constructs

In addition to existing and ongoing federal actions, the states have been proposing

Exhibit 3. Methane Climate Action Plan

- Develop new guidelines to assist states in reducing ozone-forming pollutants from existing oil and gas systems in nonattainment areas and the Ozone Transport Region
- Require reporting in all industry segments and explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions
- Update venting, flaring, and leaks standards
- Reduce well methane emissions

and implementing a steady stream of permitting and operating requirements to address emissions from oil and gas operations. State permit applications and operating requirements differ among themselves in regard to such elements as:

- Permit application submission timing,
- Information included in the application,
- Emission limits, and
- Reporting requirements.

Many of these differences are driven by a state's existing permitting structure, exemption criteria, and the state's State Implementation Plan (SIP), which outlines a state's strategy to attain and maintain the NAAQS. SIPs must take into account a wide variety of factors, including type of emission sources, emissions control requirements, state resources, etc. (EPA, undated c).

Pennsylvania

Prior to August 10, 2013, the Pennsylvania Department of Environmental Protection's (PADEP) Air Quality Permit Exemption List included an "automatic" blanket exemption for oil and gas exploration and production facilities and operations (PADEP, 2013). On August 10, 2013, the PADEP removed the blanket exemption and replaced it with stringent exemption criteria, which exempt the source category from the

Exhibit 4. Information Required for the PA Category No. 38 Exemption Criteria

- Perform the LDAR test within 60 calendar days after the start of production (well begins producing continuously to the flow line or to a storage vessel for collection), and annually thereafter. Tests should include use of an optical gas imaging camera such as a FLIR camera or a gas leak detector or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks.
- Submit a compliance demonstration to the PADEP within 180 calendar days after the "well completion" (the 180 calendar day clock for compliance demonstration begins once flowback starts). The demonstration must include:
    - Completion notification,
    - Demonstration that completion complied with "Green Completion" requirements,
    - Storage tank emission calculations,
    - Demonstration that completion complies with Subpart OOOO requirements, and
    - Information demonstrating compliance with 95% VOC reduction requirement from tanker truck load-out.
- Combined VOC emissions from all the sources at the facility are less than 2.7 tons on a 12-month rolling basis (excluding VOC emission controlled by a flare or included in Plan Approval)
- Combined NO_x emissions from the stationary internal combustion engines at wells, and wellheads are less than 100 lb/hr, 1,000 lb/day, 2.75 tons per ozone season (the period begins May 1 of each year and ends on September 30 of the same year), and 6.6 tons per year on a 12-month rolling basis (Source: PADEP, 2013).

permitting; however, operators are required to demonstrate compliance to be eligible. To demonstrate compliance with the Category No. 38 exemption criteria, information that the operator is required to complete/submit is shown in the table in **Exhibit 4**.

The PADEP does not require annual compliance reports. However, beginning in 2011, unconventional operators were required to complete an annual emission inventory by March 1 of each year that includes emissions from dehydration units and drill rigs, and fugitive emissions from connectors, flanges, pump lines, pump seals and valves, heaters, pneumatic controllers and pumps, stationary engines, tanks, pressurized vessels and impoundments, venting and blow down systems, well heads, and well completions (PADEP, 2011).

After all of the work in developing the Category No. 38 Conditional Permit Exemption program, it appears that the PADEP will be shifting to a general permit program. In particular, the PADEP is expected to issue a draft General Permit by fall 2016 for oil and gas exploration, development, and production facilities, including well pads, which will replace the Category No. 38 program.[3] Therefore, once the general permit is finalized, operators will need to either obtain a General Permit, a Plan Approval, or apply for a Permit Determination. It is our understanding that the General Permit will include emission limits, leak detection, and BAT (Best Available Technology) requirements at unconventional gas well pads for sources including dehydrators, engines, turbines for compressor engines at well pads, pigging operations, liquid unloading venting, and gas processing units, storage tanks, and truck load-outs.

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Ohio

Similar to Pennsylvania, Ohio operators were typically exempt from air permitting, as operations usually met the De Minimus Exemption (Ohio Administrative Code (OAC) rule 3745-15-05) prior to the introduction of fracking. Unlike Pennsylvania, Ohio requires operators to obtain a permit prior to the start of production. To address permitting requirements, Ohio utilized its existing General Permit program to develop two General Permits: GP-12.1 and GP-12.2 for oil and gas operations (Ohio EPA, undated a). The GPs, which expire after 10 years, cover emission sources at most well sites, including internal combustion engines, generators, dehydration systems, storage tanks, and flares. The General Permits are nearly identical, although GP 12.2 allows for a large flare (up to 32 million British Thermal Units per hour [MBtu/hr]), rather than the small flare in GP-12.1 (10 MBtu/hr), but restricts the natural gas engines to less horsepower (Hp) (1,800 Hp down to 1,000 Hp). The Ohio EPA typically issues the General Permit within 45 days of receipt of a complete permit application.

The General Permit's conditions, which are very prescriptive, include emissions limits, operating restrictions, and monitoring and reporting requirements, as well as stack height and distance to the property line requirements for engines. In addition, the General Permit identifies a number of requirements for control devices, including the flare(s) for the glycol dehydration units and flash tank equipment, when necessary; there may be a separate flare for each, or one combined site flare.

The General Permit also requires that an LDAR program be implemented to monitor and repair leaks from each pump, compressor, pressure relief device, connector, valve, flange, vent, cover, any bypass in the closed vent system, and each storage vessel. Monitoring for leaks, using a forward looking infrared (FLIR) or a portable VOC analyzer, must be completed within 90 days of startup, then every 3 months for at least a year. At that point, monitoring can be reduced to once every 6 months, and then further reduced to once a year if the percentage of leaking equipment is 2% or less.

Unlike Pennsylvania, operators are required to submit an Annual Permit Evaluation Report once per year to the Ohio EPA. This report demonstrates compliance with relevant permit conditions, compliance with quarterly LDAR, and tracking of 12 month rolling emissions (Ohio EPA, 2012).

The Ohio EPA also requires particulate matter permitting if dust emissions exceed 10 pounds per day (lb/day) (OAC rule 3745-15-05). If the dust emissions exceed 10 lb/day, then the operator needs to obtain a permit, which will require that appropriate dust suppression practices be implemented. Permit coverage is typically obtained via General Permit GP-5.1 or GP-5.2 (Ohio EPA, undated b).

West Virginia

Similar to Ohio, the West Virginia Department of Environmental Protection (WVDEP) requires well pads to obtain an air permit if the potential emissions (operating at maximum capacity for 8,760 hours per year) exceed the emissions rates listed in the West Virginia Title 45 Legislative Rule, Department of Environmental Protection Air Quality Series 13 (W.V.45CSR13), as summarized below:

- 6 (lb/hr or 10 tons per year (tpy) of any regulated air pollutant,
- 144 lb/day of any regulated air pollutant,
- 5 tpy aggregated HAP, and
- State toxic air pollutant thresholds tripped.

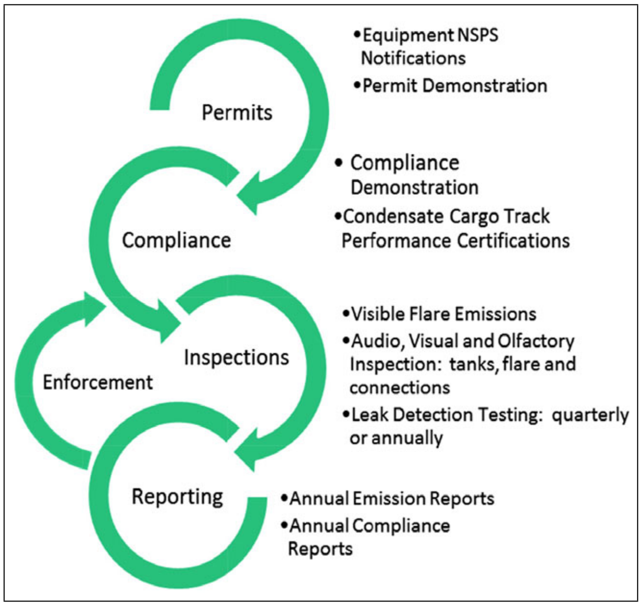
In addition to the noted emissions rates, if a flare is operated for more than 30 days or any equipment is subject to NESHAP or NSPS requirements, a permit must be obtained (W. Va. Code R. § 45-6-6.1a). Operators must obtain a permit prior to installing equipment onsite, which the WVDEP clarifies to mean that emission units cannot be partially installed or erected and must be stored the way they were delivered if they are to be stored onsite (WVDEP, 2013). However, permanent storage tanks can be set on their foundations, but no gauges or plumbing can be installed (WVDEP, 2014). To streamline the permitting process, the WVDEP developed a General Permit G70-A (WVDEP, 2013).

The permit, which typically requires 90 days to obtain after submission of a complete application, includes appropriate federal NSPS and NESHAP requirements (Subpart OOOO, JJJJ, IIII, et al.), operating and design requirements, use of EPA emission-compliant engines, etc. In addition, the permit has a siting provision, which states that no source shall be constructed within (as paraphrased from the regulation) 300 feet of any occupied dwelling, business, public building, school, church, community, institutional building or public park. However, the owner of an occupied dwelling or business may elect to waive the 300-foot siting criteria as described in Class I General Permit G70-A, Section 3.1 (WVDEP, 2013). Like Pennsylvania, the GP-70A permit does not require annual compliance reports or emission inventory reports unless requested. However, the WVDEP expects the operator to have all compliance information available for review when their facilities are inspected.

The permit, which typically requires 90 days to obtain after submission of a complete application, includes appropriate federal NSPS and NESHAP requirements (Subpart OOOO, JJJJ, IIII, et al.), operating and design requirements, use of EPA emission-compliant engines, etc.

On November 2, 2015, General Permit G70-B was issued to supersede G70-A by the end of 2015. The intent was to make the

Exhibit 5. Reporting Emissions Challenges



language consistent with federal regulations and add new conditions to the G70-A framework. On December 1, an industry group and one operator appealed this new permit. The appeal was settled with minor changes to the G70-B, which was reissued as G70-C.[4] Public comment for this revision closed in May and is expected to be finalized in the summer 2016.

Exhibit 6. Root Causes of Compliance Failure

- Lack of awareness
- Lack of planning
- Lack of resources
- Lack of communication
- Staff turnover

Meeting the Compliance Challenge

At any time, an EPA or a state agency inspector can request that an operator produce records at any or all of its well pads, as shown in **Exhibit 5**. Although complicated and confusing, it is of paramount importance that each operator understands his or her appropriate permitting, operating, emission limits, and recordkeeping and reporting obligations. An organized approach is needed to address this regulatory burden.

Failure to complete, maintain, and be able to produce required records upon request can result in serious consequences for an operation. The root causes of compliance failure are numerous, as shown in the table in **Exhibit 6**. Because operators typically have anywhere from tens to hundreds of wells spread across a geologic basin, which may also span several states, it is imperative that operators establish an air management system that addresses existing air emissions requirements in light of their specific operations. Furthermore, operators must be able to recognize and incorporate equipment modifications and ever-changing regulatory requirements. Unfortunately, many operators do not necessarily have the expertise to implement an effective emissions management system.

Emissions Management System (EMS) Implementation

HRP has been working with operators in the Marcellus and Utica shale basins to create a systematic emissions management system. HRP's Emissions Management System (EMS) can help operators maintain compliance with the myriad of regulatory requirements. The system is designed such that field data can be collected and the compliance reports generated automatically. The EMS implementation typically consists of:

- Communication infrastructure,
- Activity requirement analysis,
- Management system development,
- Management system implementation, and
- Management system review.

These steps are described in more detail in the table in **Exhibit 7**.

Emissions Management System Case Study

Although the company in this case study was well established in other basins, it was a relatively new Marcellus Shale operator. The company completed an internal audit of its Marcellus Shale operations and determined that its operation was not meeting air emissions regulatory requirements. In 2012, the company retained the authors' consulting company to establish a compliance system for its operations in the Marcellus Shale basin.

Following the five-step implementation strategy outlined previously, the company's compliance requirements were identified and then the existing system was evaluated against these requirements. From this evaluation, it was determined that the staff did not understand the regulatory requirements; information was not being transferred to those responsible for recordkeeping and reporting; and there was a lack of common terminology in use throughout the company.

With the issues identified, the process of implementing the EMS for the company began. The first step was training personnel to understand their particular roles and responsibilities.

Next, the team reviewed field data validity to ensure that it was within acceptable ranges and to address errors and act on issues of importance. For a reporting system based on operations, whether drilling, completion, or production, the facility location is a key element. This required the creation of site and process identifiers to track reporting. To ensure proper checks and balances on reporting, HRP helped implement a recordkeeping system that properly cataloged data for efficient retrieval and that meets minimum document/data retention requirements, a period that is typically 5 years.

Finally, a program of periodic reviews of federal and state regulatory changes was established to evaluate impacts to the recordkeeping system and to make appropriate adjustments. This assures that the company will stay in compliance as emissions regulations continue to evolve. **Exhibit 8** is a graphical depiction of the EMS implementation for this particular operator.

The operator has been using the system since the promulgation of Subpart OOOO requirement in 2011 and has maintained compliance with all air regulations. They chose to keep the consultants on as the system operator, reducing the need for internal compliance staff.

Conclusions

Initially, air regulations for oil and gas operations focused on large sources of

Exhibit 7. Action Elements for a Successful Air Emissions Management System

Communications

- Establishes responsible positions to implement tasks and ensures appropriate resources are allocated and activities are communicated between departments so that compliance deadlines are achieved
- Establishes common terminology for drilling, completion, production, field, and health, safety, and environmental (HSE) personnel

Activity requirement analysis

- Identify requirements associated with drilling, completion, and production
- Utilize Air Compliance checklist to ensure appropriate information collection between departments
- Based on the activity, equipment, and state location air requirements including inspections, emission limits, recordkeeping and reporting must be determined
- Review draft well pad designs to minimize and ensure regulatory compliance requirements are addressed; during the review the HSE may be able to suggest design modification that will reduce potential compliance costs, such as using an EPA compliant flare or engines that have EPA emission certification, thereby eliminating stack testing costs

Management system development

- Optimize reporting dates to facilitate timely report completion and maximize staff effectiveness
- Standardize field data collection to minimize errors and maximize staff efficiency
- Develop and apply consistent emission factors to ensure reporting consistency and defensible data
- Develop and utilize an emission tracking system appropriate to the activity and location: for example, the system needs to address specific state and GHG reporting requirements, such as emissions tracking on a 12-month rolling basis required by Ohio, whereas Pennsylvania requires a calendar year unless engines are present onsite or VOC emissions are not treated
- Identify and track compliance events (e.g., inspections, LDAR, and reports). For example, the system may need to track up to 50 periodic reviews and a periodic compliance events at a well pad over a year's time; it is important to be able to track the events to ensure they were completed and inspections/reports are maintained

Management system implementation

- Train personnel in their responsibilities: in general, drilling, completion, and production personnel need to understand their roles in the management system, which generally consists of information sharing; field personnel need to understand the information they are responsible for collecting and its value, and be able to recognize obvious compliance issues
- Review validity of field data to ensure it is within acceptable ranges and address errors, as well as act on issues of importance
- Complete required reports based on operation and location
- Implement a recordkeeping system that properly catalogs data for efficient retrieval and meets minimum retention requirements, typically 5 years
- Conduct periodic reviews of federal and state regulatory changes to evaluate impacts to the recordkeeping system and adjust accordingly

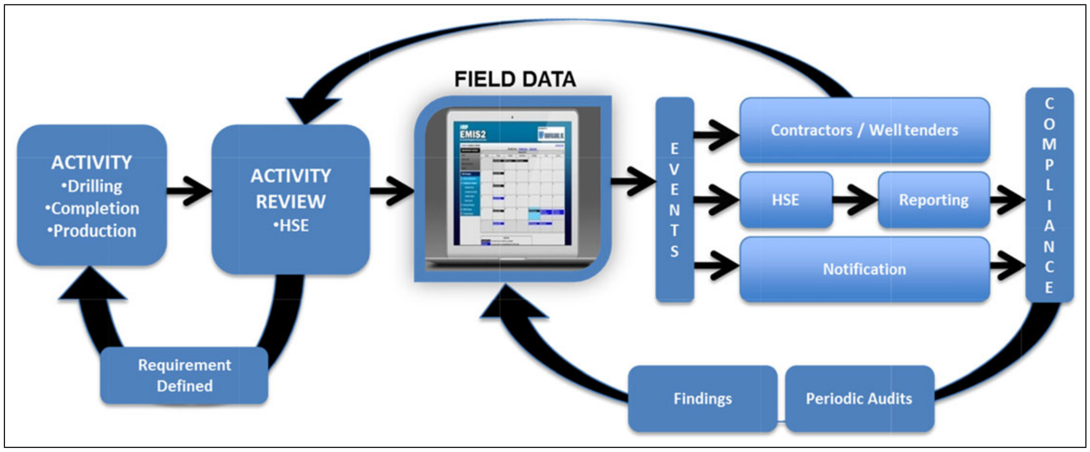
Management system review

- Complete periodic reviews of the management system to ensure tasks are completed; information is available, properly catalogued, accurate, and complete. Address any noted deficiencies.
- Review and audit the system to identify obvious compliance or noncompliance trends so that corrective measures can be put in place to minimize future failures (culture, personnel, training, resources, etc), which may consist of staffing changes, training, policy development, resource reallocation, etc.

hydrocarbon emissions in urban areas, such as refineries in Houston. However, due to the increased number of unconventional wells and their associated air emissions, state and federal agencies have been busy developing and implementing air regulations that include permitting, operating, and recordkeeping and reporting requirements. This blizzard of requirements can lead to noncompliance. Root causes of noncompliance include lack of awareness, planning, and resources as well as staff turnover.

To maintain compliance, it is of paramount importance that the various operational departments communicate weekly, if not daily, with the health, safety, and environmental (HSE) department to ensure that requirements are addressed. Proactive operators will also include the HSE department in the review of well pad designs so that air requirements can be reduced, and in some cases eliminated, through planning and a thorough understanding of air requirements. In addition, the HSE department must

Exhibit 8. Environmental Management System Design Applied to Air Emissions.



constantly review federal and state publications to ensure that the latest regulatory changes are reviewed and integrated into the compliance system.

Because of the numerous requirements and the variety of people and positions requirements to maintain and demonstrate compliance, many operators are implementing electronic compliance systems. The systems incorporate all of the compliances tasks, Standard Operating Procedures, emission tracking, and a method to easily retrieve compliance documents. It is also important that HSE departments be keenly aware of proposed and promulgated regulations that will potentially impact operations. No two systems will be the same, as each system needs to address the complexity of state and activity requirements and consider the risk tolerances of the operator.

Notes

1. This content in this section is based on Seguljic and Thomas (2015). Evolving air regulations are causing inconsistencies across the Marcellus Shale Basin. SPE-177289, Society of Petroleum Engineers, Richardson, TX.

2. In 2014, 3.20 billion metric tons CO2e were reported by direct emitters. The largest emitting sector was the power plant sector with 2.1 billion metric tons CO2e, followed by the petroleum and natural gas systems sector with 236 million metric tons (MMT) CO2e and the chemicals manufacturing sector with 177 MMT CO2e (see https://www.epa.gov/ghgreporting/ghgrp-2014-reported-data and click the “Reported Emissions” tab).

3. For a good discussion of this proposed change, see PADEP (2016).

4. According to the WV DEP, “The issues of the appeal included permit conditions that pertained to flare and/or enclosed combustion device sizing and leak detection and repair (LDAR) language.” In March 2016, the WV DEP and the appellants agreed to minor changes to G70-B raising the total maximum design heat input for all registered flares or enclosed combustion devices allowed maximum design heat Input from 30 to 36 MM BTU/hr and modified the leak detection and repair language so that it only applies to closed vent systems. This proposed version is designated as G70-C (see WVDEP, undated).

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