MANAGING THE REQUIREMENTS OF EVOLVING AIR REGULATIONS ACROSS THE MARCELLUS AND UTICA SHALE REGION
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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 of to the natural gas supply of the United States - large enough to be called a “super giant” gas field.1 With the addition of the Utica Shale, the northeastern USA is poised to be a major producer for generations.

The Marcellus and Utica shale region underlies the states of Pennsylvania, Ohio, and West Virginia. The area is characterized by older, established communities with sporadic legacy oil and gas production. The breadth and scale of shale operations across the region has led to public concerns about potential impacts to air quality, and additional greenhouse gas requirements.2 Following a similar effort to reduce water impacts, environmental advocacy groups began pressuring regulators to control air emissions from oil and gas operations.

In response to this public pressure and lawsuits, state and federal regulators started 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.3 In addition, the Obama administration’s commitment to enact policies on climate changes is expected to have significant impacts on the oil and gas operators.4

THE DEVELOPING AIR QUALITY CONCERN
Marcellus Shale gas development and production activities can be a significant source of air pollution.5 Table 1 lists the 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 level. 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. 2013, determined that Marcellus development will lead to a significant increase in NOx and VOC emissions in the region. It is projected that in 2020, Marcellus development will contribute 12% (6–18%) of the total NOx and VOC emissions in the Marcellus region.6

THE EVOLUTION OF AIR EMISSIONS REGULATION FROM OIL AND GAS OPERATIONS7
Prior to the widespread application of hydraulic fracture stimulation to shale formations, the region’s oil and gas industry typically installed a single well per location with development and production air emissions far less than a modern shale operation. Since oil and gas emissions from these single well sites was relatively minor, federal air regulations associated with oil and gas operations focused on mid-stream 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 to GHG (i.e. methane) emissions.

All of this changed with the increased oil and gas activity using hydraulic fracture stimulation, horizontal drilling and multi-well drilling pads which dramatically increased emissions from production operations. A series of events focused attention on upstream oil and gas emissions.
In 2012, the 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 while Pennsylvania eliminated permitting exemptions. Further, various court cases enabled the EPA to regulate GHG for which oil and gas systems are the second largest stationary source.\textsuperscript{8}

### Table 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 to 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 to 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, NOx, 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, waste water, 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 NOx, 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, etc.), 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 loose fittings, cracks, etc. There is a high degree of uncertainty regarding methane leakage rates. Estimates of fugitive emissions vary, ranging from 1 – 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:

### Federal Regulatory Construct

All current regulations stem from the federal Clean Air Act (CAA) which came into force in 1970. This regulation created pollutant categories and source categorization. Also, it defined the role of the states in the regulatory process.

### NAAQS

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 standard to a level within the range of 0.065 to 0.070 parts per million (ppm), and 0.065 to 0.070 ppm, respectively, by October 2015.\textsuperscript{9}
This lowered NAAQS will require the EPA and states to develop stricter emission controls for sources of VOC and NOx such as oil and gas development and production.

Operating Requirements
The EPA first regulated the oil and gas industry when they issued a New Source Performance Standard (NSPS) in June of 1985, which covered the processing and transmission of oil and natural gas. However, it took another 22 years before the EPA regulated the production of natural gas. In August, 2012, the EPA issued the new emission standard 40 CFR Part 60, Subpart OOOO for the oil and natural gas industry, which applies to a variety of equipment and operations (40 CFR Part 60, Subpart OOOO) 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 (scfh), that is located between the wellhead and the point of custody transfer to the natural gas transmission
- Storage vessels

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, record-keeping and reporting requirements. One of the most significant requirements affects the venting and flaring of natural gas during well completion: From adoption to January 2015, completion gas had to be combusted (flared) and after January 2015, combustion gas must be routed and recovered into collection systems/gas flow lines, etc. (often called green completions).

In conjunction with the Subpart OOOO promulgation, the EPA also revised glycol dehydrators requirements under subpart HH to include leak detection and repair (LDAR) for large units, and emission controls requirements for small units (with a flow rate less than 85,000 scmd or 1 ton benzene emission per year).

To control NOx and Hazardous Air Pollutant emission from stationary internal combustion engines (e.g. used to power wellhead compressors), the EPA recently established NSPS and 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, record-keeping 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, record keeping and reporting requirements.
- 40 CFR 63, Subpart ZZZZ (NESHAP) – subjects stationary spark and compression ignition installed prior to July 2006 to emissions limits, maintenance, recordkeeping, and reporting requirements depending 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.

GHGs
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. In November 2010, the EPA promulgated regulations under 40 CFR 98, Subpart W that required the monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems that emit greater than or equal to 25,000 metric tons of CO2 equivalent per year throughout the entire geologic basin. 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. As an example, under this definition GHG emissions from all wells under common ownership in the Marcellus Basin (i.e. Pennsylvania, Ohio and West Virginia) must be totaled.
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Although the EPA has acknowledged that it has no capacity to deal with all of the incoming data from the GHG inventory, the EPA intends to use the data to assist in the conducting of 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 Clean Air Act.\textsuperscript{16}

Since the initial rule, the EPA proposed revisions to Subpart W including revising calculation methods and monitoring and data reporting requirements.\textsuperscript{17} 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.\textsuperscript{18}

In addition, the White House issued its “Methane Climate Action Plan-Strategy to Cut Methane Emissions” on January 14, 2015 that includes a goal to reduce U.S. methane emissions by 40 to 45% from 2012 levels by 2025. The plan, highlighted in Table 2, states that the bulk of the cuts will be focused on the oil and gas industry pursuant to new regulatory actions which will primarily originate with the EPA and also from the Bureau of Land Management, Department of Energy and other federal agencies.

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\textbf{Table 2: Methane Climate Action Plan} \\
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\item Develop new guidelines to assist states in reducing ozone-forming pollutants from existing oil and gas systems in non-attainment areas and the Ozone Transport Region
\item 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
\item Update venting, flaring, and leaks standards
\item Reduce well methane emissions
\end{itemize}
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STATE REGULATORY CONSTRUCTS

In addition to existing, and ongoing federal actions, the states have been proposing 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 including: permit application submission timing; information included in the application; emission limits; and reporting requirements. Many of these differences are driven by the state’s existing permitting structure, exemption criteria and the state’s State Implementation Plans (SIP) which outlines a state’s strategy to attain and maintain the NAAQS. SIP Plans must take into account a wide variety of factors including type of emission sources, emissions control requirements, state resources, etc.\textsuperscript{19}

\textbf{Pennsylvania}

Prior to August 10, 2013 the PADEP’s Air Quality Permit Exemption List included an “automatic” blanket exemption for oil and gas exploration and production facilities and operations.\textsuperscript{20}

On August 10, 2013 the PADEP removed the blanket exemption and replaced it with stringent exemption criteria, which exempt the source category from the 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 Table 3.
Table 3: Information Required for the PA Category No. 38 Exemption Criteria

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

- Perform leak detection and repair (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
  - 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 VIOC emission controlled by a flare or included in Plan Approval)
  - Combined NOx emissions from the stationary internal combustion engines at wells, and wellheads are less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period begins May 1 of each year and ends on September 30th of the same year), and 6.6 tons per year on a 12-month rolling basis.

Sources:

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, drill rigs, fugitives such as 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.21

Ohio
Similar to Pennsylvania, Ohio operators were typically exempt from air permitting since operations usually met the De Minimus Exemption (OAC rule 3745-15-05) prior to the introduction of fracking. Different than Pennsylvania, Ohio requires operators to obtain a permit prior to the start of production. To address the 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.22

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 except GP 12.2 allows for a larger flair (up to 32 mmBtu/hour, rather than 10 mmBtu/hr) but restricts the natural gas engines to less horsepower (1,800 Hp down to 1,000 Hp). The Ohio EPA typically issues the General Permit within 45 of receipt of a complete permit application. The General Permit’s conditions, which are very prescriptive, include emissions limits, operating restrictions, monitoring and reporting requirements, as well as stack height and distance to the property line requirements for engines. In addition, it 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.
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The General Permit also requires that a 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 FLIR or a portable VOC analyzer, must be completed within 90 days of startup, then every three months for at least a year. At that point, monitoring can be reduced to once every six 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 which demonstrates compliance with relevant permit conditions, compliance of 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 (Ohio Administrative Code rule 3745-15-05). If the dust emission exceeds 10 pounds/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.

West Virginia
Similar to Ohio, the West Virginia Department of Environmental Protection (WVDEP) requires wellpads to obtain an air permit if the potential emissions (operating at maximum capacity for 8760 hours/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 tpy of any regulated air pollutant
- 144 lb/day any regulated air pollutant
- 5 tpy aggregated HAP
- 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 on-site. However, permanent storage tanks can be set on their foundations, but no gauges or plumbing can be installed. To streamline the permitting process, the WVDEP developed a General Permit G70-A.

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 no source shall be constructed within 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. The permit does not include annual compliance or emission reporting, unless requested.

Like Pennsylvania, the GP-70A permit does not require annual compliance reports or emission inventory, however the WVDEP expects the operator to have all compliance information available for review when inspected.

MEETING THE COMPLIANCE CHALLENGE
At any time an EPA or a state agency inspector can ask for the operator to produce records at any or all of its well pads, as shown in Figure 1. Although complicated and confusing, it is paramount that each operator understands their appropriate permitting, operating, emission limits, 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 have serious consequences for an operation. The root cause of compliance failure is multifold, as shown in Table 4, and can have serious consequences. Since operators typically have anywhere from tens to hundreds of wells spread across a geologic basin, which may include several states, it is imperative that operators establish an air management system that addresses existing air requirements in light of its operations, and has the ability to recognize and incorporate equipment modifications and ever-changing regulatory requirements. Many operators, however, do not necessarily have the expertise to implement an effective emissions management system.

Table 4: Root Causes of Compliance Failure

- Lack of Awareness
- Lack of Planning
- Lack of Resources
- Lack of Communication
- Staff Turnover

Emissions Management System Implementation

HRP is working with operators in the Marcellus and Utica shale basins to create a systematic emissions management system. As part of HRPs Environmental Management System (EMS), the system 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 1) communication infrastructure, 2) activity requirement analysis, 3) management system development, 4) management system implementation, and 5) management system review. These steps are described in more detail in Table 5.
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### Table 5: 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 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 on-site 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, 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 five 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 non-compliance 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.
EMS Case Study

Though an established company in other basins, a relatively new Marcellus Shale operator completed an internal audit of its Marcellus Shale operations and determined that its operation was not meeting regulatory air requirements. The company retained HRP to establish compliance system for its operations in the basin.

Following the 5 step implementation strategy, HRP identified the company’s compliance requirements and evaluated existing system. As a result, HRP determined that the staff did not understand requirements; information not transferred to those responsible for record-keeping and reporting; and that there was a lack of common terminology in use throughout the company.

HRP then began the process of implementing the EMS for the company. The first step was training personnel to understand their particular roles and responsibilities.

Next, HRP reviewed field data validity to ensure it is within acceptable ranges and address errors, as well as act on issues of importance. A reporting system based on operation, whether drilling, completion or production, and facility location is was a key element. This required site and process identifiers for tracking reporting. To ensure proper checks and balances on reporting, HRP helped implement a record-keeping system that properly cataloged data for efficient retrieval and meets minimum retention requirements, which is typically five years.

Finally, HRP helped establish a program of periodic reviews of federal and state regulatory changes to evaluate impacts to the recordkeeping system and adjust accordingly. This assures that the company will stay in compliance as emissions regulations continue to evolve. Figure 2 is a graphical description of the EMS implementation for this 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 HRP on as the system operator reducing the need for internal compliance staff.
CONCLUSIONS

Initially, air regulation for oil and gas operations focused on large sources of hydrocarbon emissions in urban areas, such as refineries in Houston. However, due to the increased number of unconventional wells and the associated air emissions, state and federal agencies have been busy developing and implementing air regulations that include permitting, operating recordkeeping and reporting requirements. The variety and depth of requirements impacting wellpads can be a blizzard of paperwork if not properly implemented. To rest easy and maintain compliance, it is paramount that the various operational departments communicate weekly if not daily with the HSE department to ensure that requirements are addressed. Proactive operators will also include the HSE department in the review of wellpad 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 group must be constantly reviewing federal and state publications to ensure that the latest regulatory changes are reviewed and integrated into the compliance system. Due to the numerous requirements and 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 document. It is also important that HSE department be keenly aware of proposed and promulgated regulations that will potentially impact operations. No two systems will be the same since each system needs to address the complexity of state and activity requirements and risk tolerances of the operator.

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