Vinson&Elkins

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A NEW SLEW OF OIL AND GAS REGULATIONS: WHAT YOU NEED TO KNOW

ENVIRONMENTAL LAW UPDATE

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Contents

Introduction

On May 12, 2016, EPA issued a slate of final rules and an information request under the Clean Air Act (the "Act" or "CAA") directed at the oil and gas industry. EPA has:

- established regulations for methane and volatile organic compound ("VOC") emissions from new, modified, and reconstructed sources in the oil and gas sector, which EPA anticipates will impact 13,000 oil wells, 94,000 well pads, and hundreds of compressor stations by 2020;
- taken additional steps towards regulating methane emissions from existing oil and gas sources by requesting information from the industry in support of developing standards;
- redefined the boundaries of the "source" used to determine whether air permitting requirements apply; and
- adopted a federal plan for new minor sources of emissions from oil and gas production in Indian country.

These rules will have widespread application to the oil and gas industry, including production, processing, transmission, and storage.

New Methane Rule

Background

For the first time ever, EPA is directly regulating methane as a greenhouse gas. EPA already has established new source performance standards for VOC and SO_2 emissions from some operations in the oil and gas sector through regulations codified as “Subpart OOOO.” Because methane comes from many of the same sources as VOCs, the Subpart OOOO regulations already limit methane emissions from the subject sources, even though not regulated as such under that regulation.

On September 18, 2015, EPA proposed to use methane emissions as a basis to broaden the reach of Subpart OOOO and to change control technology requirements for an extended list of equipment and facilities. This new rule — signed last week by the EPA Administrator — is codified as “Subpart OOOOa” or “Quad Oa.” The new rule has two main parts: (1) mandating that control devices or practices be used to reduce methane and VOC emissions from certain equipment by 95% and (2) fugitive emission leak detection and repair (“LDAR”) requirements that would apply only to well sites and compressor stations.

Does this rule apply to my facilities?

Quad Oa only applies to “affected facilities” — specific types of equipment or facilities that are new, modified, or reconstructed after September 18, 2015. These terms are specifically defined in the regulations and explained further below. Existing equipment that has not been altered after September 18, 2015 is not required to comply with this new rule.

Requirement	Subpart OOOO	Proposed Rule	Final Quad Oa
Regulates VOCs	Yes	Yes	Yes
Regulates Methane	Not directly	Yes	Yes
Hydraulically Fractured Oil Well Completions	No	Yes	Yes
Hydraulically Fractured Gas Well Completions	Yes	Yes	Yes
Fugitive Emissions (Leaks) at Well Sites and Compressor Stations	No	Yes	Yes
Fugitive Emissions (Leaks) at Natural Gas Plants	Yes	Yes	Yes
Pneumatic Pumps	No	Yes	Yes (but not at compressor stations)
Pneumatic Controllers	No	Yes	Yes

When does Quad Oa go into effect?

Different aspects of the rule have different “effective dates,” after which affected facilities must comply with the new requirements. These effective dates range from 60 days to one year, and the clock will start once the Quad Oa rule is published in the Federal Register. This may take several more weeks, but companies should keep an eye out for publication so they are not caught off-guard when the various requirements go into effect.

EPA will directly enforce this new rule. Members of the public can also bring litigation in the form of a Clean Air Act citizen suit to enforce the rule’s requirements. These same standards can also be incorporated into permit requirements or other air programs through future rulemakings. States can also choose to incorporate some, or all, of the rule into their own state laws and programs.

Standards for Specific Equipment

Quad Oa requires wet seal centrifugal compressors — except those located at a well site — to achieve 95% control efficiency by capturing and routing VOC and methane emissions to a combustion control device. Alternatively, centrifugal compressors can use dry-seal systems, or capture gas from centrifugal compressor seals and route it back to a low-pressure fuel gas system.

For reciprocating compressors, owners or operators must replace rod packing systems every 26,000 hours of operation or every 36 months. Alternatively, operators can route emissions from the rod packing through a closed-vent system under negative pressure. Owners or operators can also apply to use an alternative method of compliance if they can demonstrate that it will result in the same emissions reductions as EPA's methods.[1]

For continuous bleed, gas-driven pneumatic controllers, the final rule sets a gas-bleed limit of zero standard cubic feet of gas per hour ("scf/h") at an individual controller for natural gas processing plants, and a limit of 6 scf/h for pneumatic controllers found anywhere else.

Pneumatic pumps at natural gas processing plants must also achieve a zero bleed gas rate. Although the proposed rule would have also regulated pneumatic pumps used at compressor stations, in a significant change for industry, EPA decided not to impose any requirements at these pumps at this time. EPA has indicated that it may reevaluate this decision based on the results of its information request, discussed further below.

Source	Requirement
Wet-Seal Centrifugal Compressors	95% emissions reduction by capture and routing to control device
Dry-Seal Centrifugal Compressors	None
Reciprocating Compressors	(1) Replace the rod packing on or before 26,000 hours of operation or 36 calendar months or (2) route emissions from the rod packing to a process through a closed-vent system under negative pressure
Pneumatic Controllers	Natural gas plants – zero gas-bleed rate All other locations – gas-bleed rate of 6 scf/h or less
Pneumatic Pumps	Natural gas plants – zero gas-bleed rate Compressor stations – None
Storage Vessel	(1) Reduce emissions by 95% by capture and routing to control device or closed-vent system to a process or (2) maintain uncontrolled VOC emissions at less than 4 tpy[2] Not required if: (1) emitting less than 6 tpy or (2) *subject to and in compliance with* 40 CFR part 60, subpart Kb; 40 CFR part 63, subparts G, CC, HH, or WW

[1] This alternative would be subject to public notice and a hearing before EPA made a determination. Owners and operators applying to use an alternative method must submit data demonstrating the reductions from their proposed alternative.

[2] This is an alternative option available in certain circumstances after 12 months of compliance, with the requirement to reduce emissions by 95%.

New, modified, and reconstructed compressor stations must conduct quarterly leak-monitoring surveys using OGI technology or EPA Method 21, beginning one year after the final rule is published in the Federal Register.

The rule requires a survey of all “fugitive emission components” at the compressor station, meaning “any component that has the potential to emit fugitive emissions of methane or VOC” and includes a long list of components the operator must monitor — including valves, connectors, open-ended lines, pressure-relief devices, compressors, instruments, and meters. The final rule clarifies that this equipment is not considered a “component” if it is already subject to other Quad Oa requirements and vents natural gas as part of its normal operation. A fugitive emission (leak) is defined as any visible emission from a fugitive emissions component observed using OGI or an instrument reading of 500 ppm or greater using Method 21. Likewise, a leak is not considered to be repaired until no emissions are visible using OGI, or the Method 21 reading is below 500 ppm.

As compared to the proposed rule, there are some ways in which the burdens have been eased for operators under the final version. For example, the timelines for initial survey after startup and for completing repairs are slightly longer, and some exceptions have been added for equipment that is difficult or unsafe to monitor. Operators can also select between OGI technology and EPA’s Method 21 for conducting surveys, whereas the proposed rule required the use of OGI. There are trade-offs to either survey approach: most companies do not have the equipment or trained personnel to perform OGI surveys in-house, but EPA’s Method 21 is a far more labor-intensive and time-consuming monitoring process, and detects much smaller leaks than most OGI cameras.[3]

In addition, EPA removed language from the proposal that would have adjusted the frequency of surveys based on the percentage of leaking components. By removing this requirement, EPA saved operators from attempting to determine a hard-number of components at their facility. Still, the final rule is much harsher on midstream operations by forcing companies to perform LDAR surveys quarterly, no matter how low their leak rates. Under the proposal, quarterly surveys were reserved for only the facilities with the highest percentage of leaking components.

Under the final rule, operators must perform an initial survey either one year after the final rule is published in the Federal Register, or 60 days after startup — whichever is later. Following that initial survey, periodic surveys will be required quarterly, and must be spaced at least 60 days apart. Repairs must be made within 30 days, unless the repair would require shutting down production. If shutdown is required, then operators must repair any leaks during the next scheduled shutdown or within 2 years, whichever is earlier. For equipment that is deemed “difficult to monitor” because it would require elevating personnel more than 2 meters, EPA only requires that the components be monitored once per calendar year. However, these “difficult to monitor” components must still be repaired within 30 days, rather than at the next scheduled shutdown. All repaired components must then be resurveyed within 30 days of the repair to ensure that no emissions are visible using OGI, or greater than 500 ppm for Method 21.

EPA has also addressed the question of how to ensure a repair addresses a particular leak found during the survey when the leak cannot be fixed on the day of the survey. In these cases, the regulations require the operator to either tag or take a digital photograph of the leaking component.

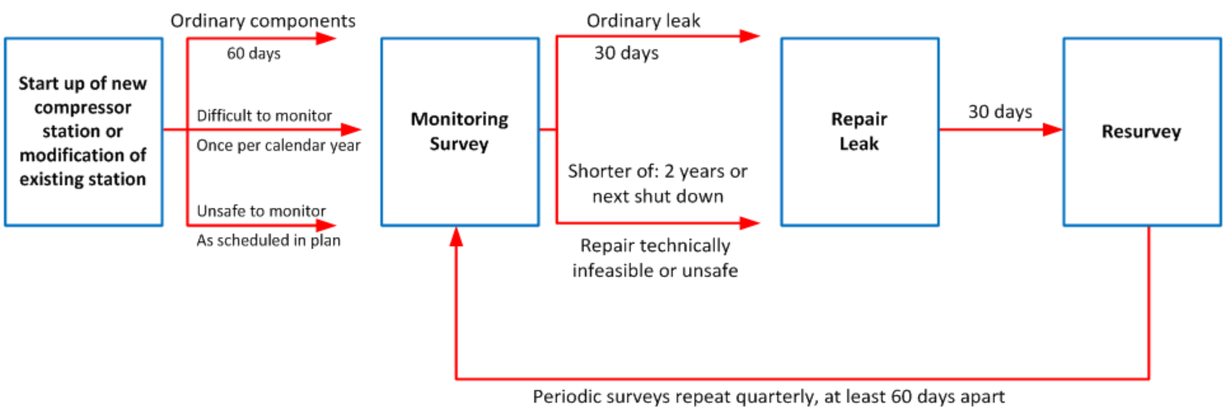
Operators must also prepare monitoring plans and comply with recordkeeping and reporting requirements. Unlike the proposed rule, which required company-wide and well-site or compressor-station specific monitoring plans, the final rule allows plans that include all compressor stations within a company-defined area. This allows businesses flexibility in deciding which stations to group together, based on how sites are internally organized and monitored by the company. For OGI, these plans must include an observation path, indicating how the survey will be conducted, to ensure that all components are visible during the survey. Under the final rule, operators are no longer required to include a digital photograph of each survey in the annual report to EPA, although they do have to retain one photo from each survey.

[3] Method 21 is a procedure used to detect VOC leaks for process equipment using a portable detecting instrument. Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. The monitoring interval depends on the component type and periodic leak rate for the component type. EPA, LEAK DETECTION AND REPAIR: A BEST PRACTICES GUIDE (2007), available at: http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf. EPA selected 500 ppm as the threshold for detecting a leak under Method 21. By contrast, the rule requires that OGI technology be capable of detecting leaks at 10,000 ppm, although EPA notes in the preamble to the rule that many OGI devices are capable of detected leaks at lower thresholds under the right conditions.

EPA also added a new provision in the final rule that allows owners and operators to apply to the agency to use an alternative method to limit fugitive emissions. However, such applications will be subject to notice and a public hearing and the applicant must include a large amount of supporting data. This option is also made available to natural gas processing plants in the final rule.

Requirement	Proposal	Final Rule
Initial Survey	Within 30 days of startup or modification	Later of: one year from publication of final rule in the Federal Register, or 60 days after startup or modification
Periodic Survey Frequency	Shifting from annual to quarterly, based on historical leak rates	Quarterly, at least 60 days between any two surveys
Survey Method	OGI	OGI or Method 21
Time to Make Repairs	15 days	30 days
Time from Repair to Resurvey	15 days	30 days
Time to Repair When It Would be Technically Infeasible or Unsafe	Soonest of: 6 months or next scheduled shutdown	Soonest of: 2 years or next compressor station shutdown
Exemptions and Extensions	Unsafe	Unsafe, difficult-to-monitor, temperature-based
Monitoring Plans	Company-wide and specific to each station	Company-defined area

This chart outlines the timeline for LDAR programs at compressor stations:



As applied to compressor stations, these LDAR requirements are triggered by a different definition of "modification" than the definition that applies to the other portions of Quad Oa. For this set of requirements only, a "modification" occurs when one or more additional compressors is installed at a compressor station, or when one or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors are replaced by one or more compressors of an equal or smaller total horsepower than the compressors being replaced, the installation of the replacement compressors does not trigger a "modification" under the LDAR requirements, but could still trigger the compressor-specific control requirements described in the previous section. This definition represents a change from the proposed rule, which would have defined a modification to include any physical change made to an existing compressor that increases compressor capacity at the compressor station, regardless of the new compressor's relative horsepower. Any "modification" to a compressor station after September 18, 2015, will trigger these LDAR requirements.

Natural Gas Processing Plants

Natural gas processing plants added or modified between April 23, 2011 and September 18, 2015 are already subject to Subpart OOOO. Those added or modified after September 18, 2015 are subject to Quad Oa. EPA has revised the text of Subpart OOOO to provide uniformity between the two sets of requirements for natural gas processing plants.

In addition to imposing the new requirements for pneumatic pumps and pneumatic controllers located at these plants, the final Quad Oa rule also amended the Subpart OOOO regulations in several respects. The new provisions include requirements for storage vessel control-device monitoring and testing, initial compliance requirements for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report, disposal of carbon from control devices, and flare design and operation standards. In addition, EPA updated an exemption to the notification requirement for reconstruction and continuous control-device monitoring requirements for storage vessels and centrifugal compressors.

There are also amendments to the LDAR program, including requirements for open-ended valves or lines, and adjustments to the compliance period for LDAR for newly affected units.

The final rule also adopts definitional changes in an effort to resolve long-pending problems with how changes in the number of components can be deemed a "modification." In the wide variety of other new source performance standards ("NSPS") governing fugitive emissions and establishing LDAR programs, the rules have always accepted that the mere addition of new components (e.g., valves) should not and cannot be deemed a modification sufficient to trigger the applicable NSPS (even though that one new valve could increase the hourly rate of emissions of the source, and so would otherwise fall under the literal definition of a modification). Accordingly, the NSPS use some version of an exclusion, such that the addition of components that is accomplished without a "capital expenditure" on a given unit is not by itself a modification of that unit. Over time, the rules (which do a great deal of internal adoptions by reference, including of subparts governing chemical plants) have become gravely anachronistic, confusing and potentially unenforceable. EPA purports to resolve this for Quad O and Quad Oa by adopting a definition of capital expenditure that updated the economic assumptions built into the depreciation model by which EPA determines whether an expenditure on equipment exceeds a prescribed fraction of the replacement cost of that equipment. Updating this definition could eliminate internal conflicts within Subpart OOOO (and even Subpart KKK) that may have impeded EPA's ability to treat equipment changes as modifications. These amendments will take effect 60 days after the final rule is published in the Federal Register.

Quad Oa expands the VOC and methane standards to apply to hydraulically fractured oil well completions and fugitive emissions from oil well completions — two sources of emissions not regulated under Subpart OOOO. Hydraulically fractured natural gas wells, which already are subject to the VOC regulations under Subpart OOOO, should be able to meet most of the Quad Oa methane emission requirements without additional upgrades or controls, because they are already subject to many of these same requirements. Quad Oa covers pneumatic controllers and pumps, as well as storage tanks at oil and natural gas well sites.

Well Completions

The well completion operational standards are largely unchanged from the proposed rule, and are mostly the same as the current Subpart OOOO standards for natural gas wells. Quad Oa expanded the requirements to also cover oil wells with a gas-to-oil ratio of more than 300 scf per stock barrel of oil produced. For this portion of the rule, a "well site" is defined as a single well that conducts a well completion operation following hydraulic fracturing or refracturing, and the requirements apply to any well site where construction, modification, or reconstruction commenced after September 18, 2015.

For subcategory 1 wells (non-wildcat, non-delineation wells),[4] Quad Oa — as proposed — required owners and/or operators to use reduced emission completions (also referred to as "RECs" or "green completions") to reduce methane and VOC emissions in combination with a completion-combustion device, such as flares or controlled combustion control devices to prevent emissions. The final rule adds an allowance for venting in lieu of combustion where combustion would present safety hazards.

Operators will have 180 days from the time the final rule is published in the Federal Register to begin using RECs. The rule does not require RECs where the use of a separator is technically infeasible. For subcategory 2 wells (wildcat and delineation wells), Quad Oa would only require owners and/or operators to use a completion-combustion device, and not RECs. Well completions done as part of a refracturing operation are not subject to this portion of the rule, as long as they meet the current Subpart OOOO requirements. However, those well sites may still be subject to the fugitive emission LDAR requirements described below.

For subcategory 1 wells, the final rule clarifies that a separator must be onsite during the entire flowback period.[5] During the initial flowback stage, subcategory 1 wells must route emissions to a storage vessel or completion vessel — such as a frac tank, lined pit, or other vessel — and separator. A second flowback stage (the "separation flowback stage") begins when the separator can function. During this stage, all salable gas must be routed from the separator to a flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for "another useful purpose that a purchased fuel or raw material would serve." If it is technically infeasible to route recovered gas as specified above, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well.

For subcategory 2 wells,[6] operators must either (1) route all flowback to a completion-combustion device with a continuous pilot flame; or (2) route all flowback into one or more well completion vessels and use a separator if it is technically feasible for a separator to function. Gas captured after the separator can function must be sent to a completion-combustion device with a continuous pilot flame. There is an exception to the combustion requirement when it could result in a fire hazard or explosion, or where high heat emissions from the combustion device could negatively impact tundra, permafrost, or waterways. Operators are not required to have a separator on site for this category of wells.

Owners or operators can also apply to EPA to use an alternative method of compliance if they can demonstrate that it will result in the same emissions reductions as EPA's methods. This alternative would be subject to public notice and a hearing before EPA made a determination. Owners and operators applying to use an alternative method must submit data demonstrating the emissions reductions from their proposed alternative.

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[4] Wildcat wells, also referred to as exploratory wells, are wells drilled outside known fields or are the first wells drilled in an oil or gas field where no other oil and gas production exists. Delineation wells are wells drilled to determine the boundary of a field or producing reservoir. Well completions done as part of a refracturing operation are not subject to this portion of the proposal as long as they meet the current Subpart OOOO requirements, but may still be subject to fugitive emissions LDAR requirements.

[5] The final rule contains an exception from this separator requirement for wells that are not hydraulically fractured or refractured with liquids, or that do not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid-collection system at the well site.

[6] Subcategory 2 includes exploratory and delineation wells and low-pressure wells.

Requirements for Specific Equipment at Well Sites

In addition to the well-completion requirements, there are separate requirements for specific types of equipment found at well sites when those particular pieces of equipment are replaced with new equipment, modified, or reconstructed after September 18, 2015. These rules are specific to the single piece of equipment that has been added or altered. For example, adding one new pneumatic controller at a well site will mean that the single new controller will be subject to these rules, but other controllers and equipment at the well site will not be impacted.

While Quad Oa does not require controls for pneumatic pumps at compressor stations, they are required at well sites. Owners and operators must route methane and VOC emissions from the pumps to a control device or process if one is on site. This requirement does not apply at certain sites if it is technically infeasible to do so. In the proposed rule, EPA requested comments on whether it should require independent third-party audits of certain requirements in the rules. While the final rule has no such requirement, it does require a certification from a qualified professional engineer indicating that it is technically infeasible to connect a pneumatic pump to an existing control device. They must also obtain certifications from a qualified professional engineer regarding the design of closed-vent systems. Pneumatic pumps that operate for less than a total of 90 days per year are exempt from the Quad Oa requirements. Owners and operators will have 180 days after the final rule is published in the Federal Register to comply with these requirements.

The rule also requires monitoring of the collective fugitive emissions from the "well site" — defined under this section of the rule as one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well, and including any separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced-water from wells not located at the well site, such as centralized tank batteries.

The requirements apply to all new well sites, or sites modified after September 18, 2015. For this portion of Quad Oa, a well site is considered "modified" when a new well is drilled at an existing well site or a well at an existing well site is hydraulically fractured or refractured. Other drilling activities (such as well workovers) will not trigger these requirements. Well sites that only contain wellheads are not covered by the LDAR requirements.

Originally, EPA proposed to exclude low-production well sites from the fugitive emissions monitoring and repair requirements. However, EPA has included low-production wells in the final fugitive emissions rules. Although EPA considered regulating emissions from liquids unloading, it did not place any requirements on these operations under the final rule.

Source	Requirement
Wet-Seal Centrifugal Compressors	None at well sites
Dry-Seal Centrifugal Compressors	None
Reciprocating Compressors	None at well sites
Pneumatic Controllers	Gas-bleed rate of 6 scf/h or less
Pneumatic Pumps	95% reduction if there is an existing control or process on site Not required if: (1) routed to an existing control that achieves less than 95% or (2) technically infeasible to route to the existing control device or process (non-greenfield sites only) (3) operated less than 90 days per year
Storage Vessel	(1) Reduce emissions by 95% by capture and routing to control device or closed-vent system to a process or (2) maintain uncontrolled VOC emissions at less than 4 tpy[7] Not required if: (1) emitting less than 6 tpy or (2) *subject to and in compliance with* 40 CFR part 60, subpart Kb; 40 CFR part 63, subparts G, CC, HH, or WW
Liquids Unloading	None

[7] This is an alternative option available in certain circumstances after 12 months of compliance with the requirement to reduce emissions by 95%.

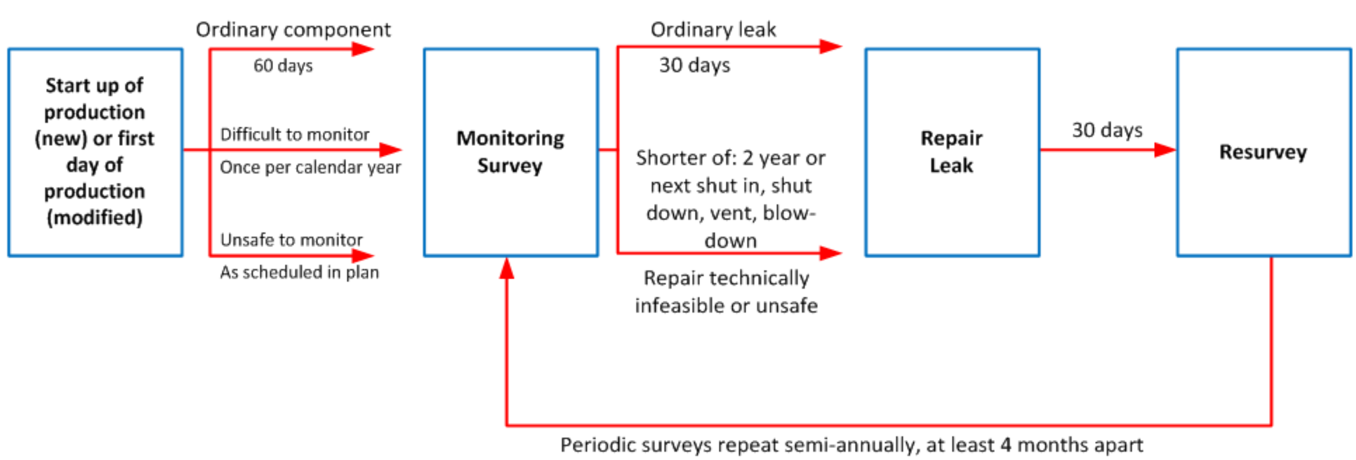
What requirements apply?

The LDAR requirements for well sites are almost identical to those for compressor stations, except that the periodic surveys only need to be conducted semi-annually, as opposed to quarterly. Repairs must be made within 30 days, unless it would be unsafe or technically infeasible to do so. All sources of fugitive emissions that are repaired must then be resurveyed within 30 days of repair completion to ensure the repair has been successful. Operators would be required to develop and implement company-defined area monitoring plans to comply with these requirements. As with the LDAR program for compressor stations, the final Quad Oa provides additional time for operators to perform the initial survey. Operators have until one year from the date the final rule is published in the Federal Register to perform their initial surveys.

For new well sites added or modified after the first year, the operator will have 60 days from the beginning of production to conduct the first survey for new wells, and 60 days after the first day of production for modified wells. These time periods are less burdensome than those initially proposed by EPA. The proposed rule would have required the initial survey to be conducted within 30 days of the later of the end of the first well completion or upon the date the site begins production for new well sites. For modified-well sites, the proposed rule required the initial survey be conducted within 30 days of the site modification.

As with the LDAR requirements at compressor stations, owners and operators can apply to EPA to use an alternative method to limit fugitive emissions.

Requirement	Proposal	Final Rule
Initial Survey	Within 30 days of completion or modification	Later of: one year from publication of final rule in the Federal Register, or 60 days after start of production (new) or first day of production (modified)
Periodic Survey Frequency	Shifting from annual to quarterly, based on historical leak rates	Semi-annually, at least 4 months apart
Survey Method	OGI	OGI or Method 21
Time to Make Repairs	15 days	30 days
Time from Repair to Resurvey	15 days	30 days
Time to Repair When It Would Be Technically Infeasible or Unsafe	Soonest of: 6 months or next shutdown	Soonest of: 2 years or next well shutdown; well shut-in; after an unscheduled, planned, or emergency vent blowdown
Exemptions and Extensions	Unsafe	Unsafe, difficult-to-monitor
Monitoring Plans	Company-wide and specific to each station	Company-defined area



What are the Costs of Compliance?

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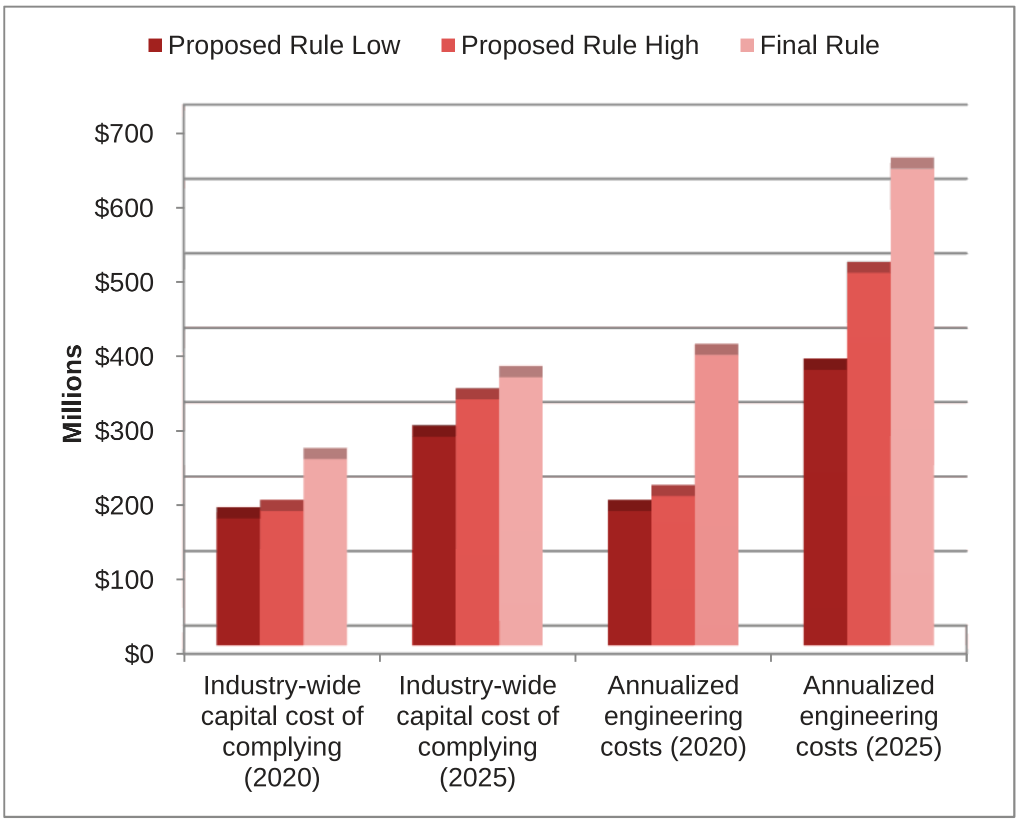
Section 111 of the Act requires that EPA consider a number of factors, including cost, in determining the best system of emission reduction ("BSER") standards. EPA raised its estimates of the total industry-wide capital cost of complying significantly since it issued the proposed rule.

Cost	Proposed Rule Estimate Range (in millions)	Final Rule Estimate (in millions)
Industry-wide capital cost of complying (2020)	$170-180	$250
Industry-wide capital cost of complying (2025)	$280-$330	$360
Annualized engineering costs (2020)	$180-$200	$390
Annualized engineering costs (2025)	$370-$500	$640



According to EPA's analysis, the largest portion of these capital costs will come from the new well completion requirements, followed by the costs of implementing the new LDAR programs, and making the changes required for pneumatic pumps. The LDAR program is expected to account for the largest portion of the engineering costs, followed by oil well completion costs. Collectively, these figures indicate that the rule's costs will be felt more heavily by the upstream segment of the industry. EPA anticipates that its well completion requirements will by 2020 affect nearly 13,000 oil wells, and its LDAR requirements, 94,000 well pads.

Despite these high industry-wide costs, EPA concludes that the proposed rule has a net economic benefit. To reach this conclusion, EPA considered the revenues that it expects operators will generate from selling the methane that would have otherwise been emitted into the atmosphere. Despite comments from the industry regarding the current state of the natural gas market, EPA has valued the methane at about $4.00 per mcf. EPA estimates that 16,000,000 mcf in 2020 and 27,000,000 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS, and is therefore estimating that $63 billion in gas will be recovered in 2020, and $110 billion will be recovered in 2025.

EPA's conclusion also is based partially on its use of a model called the Social Cost of Methane. EPA used this model to place a present-dollar value on projected future benefits to the climate from reducing methane emissions. Based on the model and the 3% discount rate that EPA used in the cost-benefit analysis, EPA determined that every ton of methane emissions that this rule prevents was worth $1,100 in 2015.

EPA's final rule contains an even *greater* estimate of the projected benefits than it had included in the proposed rule. EPA now estimates that this rule will result in "methane-related monetized climate benefits" of between $360 million in 2020 and $690 million in 2025 using a 3% discount rate. EPA estimates that this rule will reduce methane emissions by 300,000 short tons in 2020 and 510,000 short tons in 2025. The majority of these emissions come from repairs to gas leaks in equipment under the LDAR program, followed by reductions from oil well completions and recompletions.[8]

[8] EPA's full cost analysis is available in the final Regulatory Impact Statement, available at: https://www3.epa.gov/airquality/oilandgas/may2016/nsps-ria.pdf.

On May 12, 2016, EPA also issued a proposed Information Collection Request ("ICR") to support development of new rules to regulate methane emissions at existing oil and gas sources. The Agency seeks public comment on two proposed mandatory surveys to oil and gas facilities before transmitting an ICR package to the Office of Management Budget ("OMB") for review and final approval. Although it apparently does not intend to issue a final rule before the Obama Administration winds down, the EPA is setting the wheels in motion for further regulatory measures that could be imposed on the oil and gas industry.

The draft ICR consists of both an "operator survey" for oil and gas production sources, and a "facility survey" for several segments of the onshore oil and gas sector: production, gathering and boosting, gas processing, transmission, storage, and export/import facilities. The facility survey will be sent to all known operators of onshore oil and gas production in the U.S., and the operator survey is proposed to be distributed to a statistically significant number of facilities within each segment.

In addition to posing a burden with a mandatory survey distributed to tens of thousands of operators, this ICR potentially heralds yet another set of requirements for onshore oil and gas facilities that would be issued after the Obama Administration. Given the far-reaching scope of the proposed ICRs, and the prospect of additional regulatory requirements, oil and gas sources should carefully review the ICR proposal, including the extensive draft questionnaires that the Agency proposes to send. The Agency suggests in its proposal that information collected through the ICR could also support an Agency effort to "explore proposing standards for new and modified units not currently covered by NSPS OOOOa."

Legal Authorities for ICR and Existing Source Methane Rule

The Agency plans to issue surveys that oil and gas facilities would be legally required to answer under Section 114 of the Clean Air Act, the statute's broad information-gathering authority. According to the Agency's May 12 proposal, non-confidential information provided in response to the ICR will be made available to the public, presenting a concern for regulated sources subject to the information requests. The Agency may use facility-specific information not only to develop new standards, but also to identify noncompliance with current standards, as part of the EPA's ongoing National Enforcement Initiative focused on oil and gas operations.

Any methane regulations for existing oil and gas sources would be promulgated under Section 111(d) of the CAA, the Act's "existing source" provision. Under Section 111(d), the EPA must develop emission standards representing the "best system of emission reduction [BSER] which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated." After the EPA establishes BSER, states must then submit plans for Agency review and approval establishing standards of performance that would meet BSER. The Agency used Section 111(d) in promulgating the Clean Power Plan rule, which left little role for state discretion in setting standards. This rule is currently subject to a stay by the U.S. Supreme Court and pending litigation in the D.C. Circuit.

Challenges Due to Number and Diversity of Sources

A threshold challenge posed by an existing source oil and gas rule is the vast number, and wide range of age, condition, and profitability of facilities. By EPA's own estimates, there are nearly 1.4 million producing oil and gas wells at approximately 698,800 onshore well sites. Aging oil and gas wells and other wells of marginal profitability could be particularly burdened by a methane rule and even sampling required by EPA's proposed ICR. In its May 12 notice, the Agency suggests a phase-in for any rules would be appropriate given the diversity of facilities, and thus seeks "more comprehensive information that will improve our understanding of what emission controls are being used . . . how those are being configured, the difficulty of replacing or upgrading controls, how much time will be needed to retrofit . . . [and] . . . what the likely costs of retrofitting are . . . ."

"Operator Survey"

The EPA's proposed ICR consists of two surveys that would be sent to oil and gas facilities. The "operator survey" is designed to collect "comprehensive information from onshore petroleum and natural gas production facilities to better understand the number and types of equipment at production facilities." This part of the ICR will collect parent-company information and detailed facility-level information including: facility name, location, and contact information; the number of producing wells, wells that have been hydraulically fractured or refractured, and capped or abandoned wells; all well identification numbers; number of tanks and compressors; as well as whether there are flares or liquids unloading at the facility. The Agency will use its definition of facility for permitting new and existing wells and consider aggregation of sources in determining what constitutes a facility.

The Agency proposes to send the operator survey to all operators of oil and gas production wells, allowing only 30 days to complete the survey. It is not clear if this timeframe and the response time for the "facility survey" discussed below would be feasible for sources. Typically, with a Section 114 request, there is an opportunity to negotiate a longer response time with the Agency based on the particular circumstances at the source.

"Facility Survey"

Part 2 of the ICR, the "facility survey," will be sent to a subset of oil and gas facilities. These sources are production, gathering and boosting, processing, compression/transmission, pipeline, natural gas storage, as well as LNG storage and import/export facilities. Within each segment, the detailed facility survey will be sent to a subset of facilities based on a statistical sampling method to collect unit-specific information on emission sources and emission-control devices or other practices employed to reduce emissions. The EPA requests comment on two proposed sampling methods for the production segment in particular: well type (heavy oil, light oil, wet gas, dry gas, and coalbed methane) and regional basin. Input is also requested on alternative methods to define the sampling population for production facilities. The Agency acknowledges that some of the facility survey data may need to be gathered based on measurements conducted by facility owners or operators, such as equipment leak-component counts and separator/storage-vessel flash analyses.

The EPA proposes to allow facility survey recipients 120 days to respond. The Agency recognizes that this component of the ICR is likely to gather information considered by facilities to be Confidential Business Information. Environmental groups and other organizations may nonetheless submit Freedom of Information Act ("FOIA") requests to obtain information about the sources identified for the detailed facility survey. Based on recent criticisms of the Agency's practices under FOIA, including a lack of national consistency in applying FOIA exemptions, there is concern that information could be released regarding these sources that is not appropriate to release to the public.

Timing and Next Steps

Comments on the proposed draft ICR will be due 60 days after publication of the proposal in the Federal Register. The Administration projects to issue the information requests by October 30, 2016. Before issuance, the EPA will need to secure approval from OMB. There will be another opportunity for the public to submit comments to OMB when the EPA submits the ICR proposal for final approval to the White House.

Given the overall timing, the task of developing and issuing any final existing source methane rule will almost certainly fall to the next administration. The new administration will have latitude in evaluating whether to develop a methane rule for existing sources based on any information gathered from the ICRs. Although the ultimate fate of an existing source-methane rule could hinge largely on the national elections, the Obama Administration is building an administrative record that a new EPA could run with (or to some extent be bound by) to finalize requirements for both existing sources and new and modified sources not subject to NSPS OOOOa. It is thus imperative that the Agency record reflect technical, cost, and legal problems with EPA's proposal and additional methane requirements as contemplated by the EPA.

Definition of “Source” and “Aggregation”

EPA’s source-aggregation proposal has been the cause of significant concern for many in the oil and gas industry who feared that the new rule would create uncertainty about whether to aggregate individual activities in the oil field, and could potentially trigger expensive and time-consuming major source-permitting requirements. In particular, many were concerned that a broader definition of a “source” that allowed more activities that emit air pollutants to be aggregated together could have resulted in additional permit requirements for upstream sites. However, the final version of the rule, which adopts a somewhat favorable definition, should generally be viewed as a win for industry. The final rule establishes that sources are “adjacent” and can be (but need not be) aggregated if the sources are located within ¼ mile of each other and use shared equipment in a way that satisfies the “common sense notion of a plant.” Importantly, this definition of “adjacent” is mandatory only for the relatively few permit programs that are directly administered by the EPA or on behalf of EPA by delegated states. **Most importantly, States and local agencies with approved permitting programs — the majority of states — may but need not adopt similar changes at their discretion; accordingly, for large parts of the U.S., the rule will have no direct effect on the existing practices of the relevant permitting authority.**

In the proposed rule, EPA considered two approaches to defining what constitutes a source for onshore oil and gas operations: one based solely on proximity, and another based on proximity within a certain distance and on functional interrelatedness beyond that distance. Under EPA’s first option, a “source” would have included all the commonly owned emitting activities within a ¼ mile of each other. Under EPA’s second proposed option, the “source” boundary would encompass not just activities within the ¼ mile distance, but all commonly owned “functionally related” equipment, regardless of distance. This “functional interrelatedness” test would have rendered it impossible to judge with confidence the scope of any source, leading to greater litigation risk, uncertainty, and costly delays in permitting determinations.

The definition of “adjacent” established in the final rule reflects portions of both options presented in the proposed rule. As proposed in option 1, the final rule states that equipment on separate surface sites located more than ¼ mile apart is not “adjacent” and, therefore, is not part of the same stationary source. EPA recognized that oil and gas operations frequently do not have fences or other distinct boundaries, and specified that the ¼ mile boundary should be measured from the center of the emitting activities for construction permits, and from the center of the equipment on each surface site for Title V permit. Additionally, in response to recommendations submitted by various commenters, EPA determined that not all emitting equipment located on separate surface sites within ¼ mile of each other will be considered “adjacent.” Instead, aggregation will only occur if the separate surface sites are within ¼ mile of each other and also share equipment necessary to process or store oil or natural gas. Equipment satisfying these criteria will meet the “common sense notion of a plant,” and will be aggregated. Alternatively, separate surface sites that do not include shared equipment, even if located within ¼ mile, will not be aggregated.

EPA believes that the clarifications contained within the final rule will “provide greater certainty for the regulated community and for permitting authorities,” and will result in “more consistent determinations of the scope of a source” by avoiding a more detailed case-by-case evaluation based on the relationship of the emitting equipment. Still, many states will likely choose to retain their existing approach to source determinations in permitting, allowing oil and gas operators to move forward without waiting to see how EPA applies the final rule in practice.

Federal Plan for Implementing the Indian Country Minor New Source Review Program

V&E

On May 12, 2016, EPA also finalized a Federal Implementation Plan ("FIP") to implement the Minor New Source Review ("NSR") Program in Indian country for oil and gas production. The FIP essentially creates a permit-by-rule for true minor sources of air emissions: rather than applying for a preconstruction permit, oil and gas sources covered by this rule can instead comply with the requirements in this FIP.

Since 2006, EPA has been working to fill what it perceived as a regulatory gap for air emissions in Indian country. Because the states do not have jurisdiction over these areas, they were not covered under the state programs for stationary sources of air emissions. While EPA can approve a tribal air program, not all areas of Indian country have an approved program. As a result, EPA began developing an NSR program to address these "gap" areas where EPA is responsible for overseeing the air program. In 2011, EPA finalized an NSR rule for new and modified minor stationary sources and to minor modifications at existing major stationary sources located in Indian country where there was no EPA-approved program in place. This previous NSR program did not apply to true minor sources in the oil and natural gas sector.[9]

The new FIP covers all new and modified true (rather than synthetic) minor sources of air emissions in oil and natural gas production and natural gas processing in Indian country. It does not apply in areas out of attainment with a National Ambient Air Quality Standard ("NAAQS") or in non-reservation areas, unless a tribe or EPA demonstrates jurisdiction for those areas. EPA noted, however, that it intends to propose using a similar FIP for NAAQS nonattainment areas as well as a way to streamline permitting.

The FIP applies eight federal air standards to reduce emissions of VOCs, nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM, PM_{10}, $PM_{2.5}$), hydrogen sulfide (H_2S), carbon monoxide (CO), and various sulfur compounds. In addition to applying the Quad Oa rules to these sources, the FIP also incorporates performance standards for VOC liquid-storage tanks, stationary compression and ignition internal-combustion engines, spark ignition internal-combustion engines, and new stationary combustion turbines. It also contains air toxics standards for industrial, commercial, and institutional boilers and process heaters; oil and natural gas production facilities; and stationary reciprocating internal-combustion engines.

The eight standards incorporated into the FIP include emission limitations, monitoring, testing, recordkeeping, and reporting. The FIP also includes requirements related to threatened and endangered species, and historic properties. Rather than using a permit application, sources subject to the FIP will register under the Federal Indian Country Minor NSR rule by using the two forms EPA has provided.[10] These sources must submit the Part 1 Registration Form 30 days prior to beginning construction, and must submit the Part 2 Registration Form, which includes emissions information, within 60 days after the startup of production. Operators of these sources will also need to determine their potential for emissions within 30 days after startup of production. The rule will become effective 60 days after it is published in the Federal Register.

For more information, please contact Vinson & Elkins lawyers Larry Nettles, Eric Groten, George Wilkinson, Andrew Stewart, Margaret Peloso, Corinne Snow, or Rachel Comeskey. Visit our website to learn more about V&E's Environmental and Natural Resources or Climate Change practices, or e-mail one of the practice contacts.

[9] A synthetic minor source is a source that could emit above the major-source thresholds, but is legally or practically restricted so that it only emits below the major-source thresholds. A "true minor source," under the Federal Indian Country Minor NSR rule means a source that emits, or has the potential to emit, regulated NSR pollutants in amounts that are less than the major-source thresholds under either the PSD Program, or the Federal Major NSR Program for Nonattainment Areas in Indian Country, but equal to or greater than the minor NSR thresholds "without the need to take an enforceable restriction to reduce its potential to emit to such levels."

[10] The registration forms are available at: https://www.epa.gov/tribal-air/final-federal-implementation-plan-oil-and-natural-gas-true-minor-sources-and-amendments or from the EPA Regional Offices.