

Emission Sources and Control Technologies Affecting Upstream and Midstream Oil and Gas

By Ivan L. London and Jay Christopher

I. Introduction

Air quality has become a lightning rod for environmental regulatory action and stakeholder disputes regarding oil and gas development in the Intermountain West as well as other parts of the United States. Beginning in the 1980s, the Environmental Protection Agency (EPA) and state and local agencies have created an array of rules applicable to drilling, natural gas processing, storage, compression, dehydration, and pipeline transportation.¹ EPA recently brought air regulations further into the spotlight by promulgating new nationally applicable rules that increase both the scope and stringency of oil and gas regulation, as well as revising existing rules.² Industry groups and environmental groups are currently engaging with EPA in litigation over the new and revised rules.³ In fact, EPA recently asked the D.C. Circuit to hold the litigation in abeyance while EPA evaluates whether to reconsider the new and revised rules.⁴ While the permanent impact, indeed, the existence, of the rules is currently “up in the air,” it is worth addressing at this point how these rules may affect oil and gas operations.

“[T]he Clean Air Act is a very complicated statute encompassing several distinct environmental programs.”⁵ Complexities and uncertainties in the new rules may “significantly impact the planning, capital investment, and time for installation of required controls” needed to achieve compliance.⁶ Moreover, the oil and gas industry contains a variety of players, from large multinationals to very small independents, with

¹ See, e.g., 40 C.F.R. §§ 63.760 to -.777 (regulating emissions of HAPs from oil and gas production facilities); 5 Colo. Code Regs. 1001-9, § XII (Colorado regulations for volatile organic compound emissions from oil and gas operations such as storage tanks).

² 77 Fed. Reg. 49,490 (Aug. 16, 2012) (codified as Subpart OOOO at 40 C.F.R. §§ 60.5360 to -.5430) (newly promulgated regulations limiting air emissions from natural gas well completions and other natural gas production and processing equipment).

³ Independent Petroleum Ass’n of America v. EPA, No. 12-1408 (D.C. Cir.) (consolidated cases).

⁴ Unopposed Motion of Respondent EPA to Sever the Challenges to the NSPS and NESHAP Rules, to Hold Litigation in Abeyance, and to Govern Further Proceedings, American Petroleum Institute v EPA, No. 12-1405 (D.C. Cir. Jan. 16, 2013).

⁵ Coalition for Responsible Regulation, Inc. v. EPA, 09-1322, 2012 WL 6621785, at *20 (D.C. Cir. Dec. 20, 2012) (Kavanaugh, C.J., dissenting from the denial of rehearing *en banc*).

⁶ See Letter from Mathew Todd, Regulatory & Scientific Affairs, American Petroleum Institute, to Bruce Moore, U.S. Environmental Protection Agency (July 25, 2012).

The views expressed in this paper are solely those of the author (or authors).

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varying degrees of regulatory compliance capabilities. Environmental regulations under the Clean Air Act (CAA) can be difficult to understand, and are often fraught with ambiguities. Additionally, the compliance verification requirements typically employed by EPA are generally suited for centralized operations and may create a whole new set of challenges when applied to distributed, unmanned operations at hundreds of thousands of wells and tens of thousands of well pads across the United States. It's not currently clear whether operators⁷ will be able to easily manage this evolution of the CAA regulatory framework, or whether the regulations will fundamentally restructure the way industry will need to approach every oil and gas development project.

This paper concentrates on the operational and regulatory aspects of the new and revised CAA regulations applicable to upstream and midstream operations. Section II focuses on upstream and midstream oil and gas equipment that may cause emissions. Section III covers EPA's new federal air regulations governing natural gas production and hydraulic fracturing, and discusses some of the challenges posed by EPA's approach. The discussions in Sections II and III should help operators tackle the new regulatory environment impacting operations.

II. Oil and Gas Equipment that May Cause Emissions

A. Well Sites

1. Natural Gas Well Drilling and Completions

Drilling rigs typically rely on diesel engines, which emit nitrogen oxides (NO_x), hazardous air pollutants (HAPs) and volatile organic compounds (VOC).⁸ After drilling, operators increasingly use hydraulic fracturing to open up the formation containing the resource.⁹ The equipment used to fracture the well typically includes large diesel engine-powered pumps, which emit NO_x, HAPs, and VOCs, to force the fracturing fluids into the formation.

Prior to turning the newly drilled and completed well to production, operators must remove accumulated fracturing fluids from the wellbore, a process referred to as "flowback." During flowback, natural gas, oil, and other liquids are expelled from the

⁷ The statutes discussed in this paper, CAA sections 111 and 112, each prohibit an "owner or operator" from engaging in certain activities. 42 U.S.C. § 7411(e) (emphasis added); *see also id.* § 7412(a)(9), (i)(1), (3). In this paper, we use the term "operator" as shorthand for the phrase "owner or operator," which is usually defined broadly in the CAA. *See id.* §§ 7411(a)(5), 7412(a)(9) ("The term 'owner or operator' means any person who owns, leases, operates, controls, or supervises a stationary source.").

⁸ EPA defines NO_x to include "all forms of oxidized nitrogen (N) compounds." EPA, Integrated Science Assessment for Oxides of Nitrogen – Health Criteria 2:1 (2008).

⁹ Natural Resources Law Center, "Hydraulic Fracturing – Oil and Gas Drilling Best Management Practices, Intermountain Oil and Gas BMP Project," <http://www.oilandgasbmps.org/resources/fracing.php> (last visited July 19, 2012).

well, releasing VOCs and greenhouse gases (GHG).¹⁰ The composition of the flowback materials changes as the flowback progresses.¹¹ Initially, the flowback consists of water, sand, and fracturing fluids. Over time, liquid flow decreases and gas and hydrocarbon vapor flow increases.¹² As gas production begins, volumes and pressures may be inadequate or the gas may not meet specifications and must be either vented or flared. In many cases, once the gas meets minimum sales specifications, the gas is routed to a sales line. Sometimes, operators must temporarily flare the gas because the gathering pipeline and processing plant infrastructure are not present.¹³ Even after an operator connects a well to such facilities, excessive gathering system pressures may necessitate short-term flaring.¹⁴ Accordingly, several states have required the use of combustion¹⁵ or capture¹⁶ of these emissions under specified circumstances.

2. Storage Vessels

Hydrocarbon liquid and produced water storage tanks are ubiquitous in upstream and midstream operations. At or near the well site, operators separate the gas-phase materials from the liquid-phase materials, and in some cases further separate the produced water from the hydrocarbon liquids.¹⁷ Operators typically store crude oil, condensate, and produced water in fixed-roof storage tanks.¹⁸ Storage tanks may emit VOCs and GHGs through working, breathing, and flashing losses. Working and breathing losses result from vapors being pushed from the tank due to the introduction of new material to the tank (working) or daytime heating of the tank (breathing). Flashing losses result from the release of dissolved gases that occurs when the pressure of the liquid phase is reduced as it travels from the separator to the storage tank. Controls for

¹⁰ See 76 Fed. Reg. 52,758, 52,756 (Aug. 23, 2011); see also 40 C.F.R. § 60.5430.

¹¹ Letter from Peter Tsirigotis, Director, Sector Policies & Programs Division, U.S. Environmental Protection Agency, to Matthew Todd, Regulatory & Scientific Affairs, American Petroleum Institute (Sept. 28, 2012), at 2.

¹² *Id.* (citing 76 Fed. Reg. 52,738, 52,757 (Aug. 23, 2011)).

¹³ U.S. Gov't Accountability Office, GAO-04-809, Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions 2-4 (2004).

¹⁴ *Id.*

¹⁵ *E.g.*, Mont. Admin. R. 36.22.1221(1).

¹⁶ 2 Colo. Code Regs. 404-1 § 805(b)(3) (COGCC regulation); Wyo. Dep't of Env'tl. Quality, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance 15, 20 (revised ed. Mar. 2010).

¹⁷ See generally EPA, Regulatory Impact Analysis, Final New Source Performance Standards and Amendments to the National Emissions Standards for the Oil and Natural Gas Industry 2-5 (Apr. 2012).

¹⁸ 76 Fed. Reg. at 52,763.

tank emissions generally rely on the use of a flare or enclosed combustor, but in some cases may also include vapor recovery.¹⁹

3. Pneumatic Controllers and Pumps

Like storage vessels, natural gas-driven pneumatic controllers and chemical injection pumps are ubiquitous in oil and gas operations. Due to a lack of electrical power at most production sites, the energy required to operate a valve or pump is often derived from the pressurized gas produced by the well. Typically, these controllers and pumps vent to atmosphere, resulting in emissions of VOCs and GHGs. In some cases, emissions can be reduced by selecting “low-bleed” or “no-bleed” pneumatic controllers or by using solar-powered chemical injection pumps. The use of “low-bleed” or “no-bleed” pneumatic controllers is much more common today and significantly reduces GHG and VOC emissions.

4. Reciprocating Internal Combustion Engines

Reciprocating internal combustion engines (RICE) can be found at well sites during various phases of the life of the well. Drill rigs, workover rigs, and completion equipment all may use RICE during certain phases of the life of the well. Additionally, some locations may utilize RICE to run stationary onsite compression for gas lift systems that remove formation liquids from the wellbore or inject gas into the gathering system. For some oil producing locations, operators may use RICE to power pumping equipment or to provide additional site electricity. Finally, many upstream vapor recovery systems use small RICE-driven compressors to collect and compress recovered vapors. RICE may be a source of NO_x, HAP, and VOCs emissions. EPA has promulgated many complex regulations that apply to RICE, but generally has not done so in a manner targeted specifically at the oil and gas industry.²⁰ While it is important for operators to know and understand the RICE regulations, they are beyond the scope of this paper, which focuses on new and revised regulations specific to the oil and gas industry.

¹⁹ 40 C.F.R. § 63.766; *see also* 77 Fed. Reg. at 49,544-545 (to be codified as 40 C.F.R. § 60.5395); *accord, e.g.*, 5 Colo. Code Regs. 1001-9, § XVII.C; Mont. Admin. R. 17.8.1603(1)(b); N.D. Admin. Code § 33-15-07; Utah Admin Code r. 307-327; Wyo., *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, supra* note 16, at 15, 20.

²⁰ *See generally* Colin G. Harris & Ivan L. London, *There’s Something in the Air: New and Evolving Air Quality Regulations Impacting Oil and Gas Development*, 58 Rocky Mt. Min. L. Inst. 6-1, 6-26 through 6-28, 2012; *but see, e.g.*, 78 Fed. Reg. 6674, 6706 (Jan. 30, 2013) (to be codified as 40 C.F.R. § 63.6675) (creating a new category of “remote stationary RICE” defined in terms of location on a natural gas pipeline).

B. Gathering Facilities and Gas Plants

1. Compressors

Compressors are used to increase the pressure of the natural gas to facilitate the movement of the gas along a pipeline or through a facility. Compressors are typically not associated with a single well or well pad but instead operate as part of a gathering system, connecting many producing locations from potentially many different operators. Compressors are also commonly found in gas processing, transmission, and in some storage operations. The two predominant compressor designs are reciprocating and centrifugal, and each relies on different sealing systems to minimize fugitive emissions of VOCs and GHGs. Depending on their application, compressors may be driven by RICE or turbines, which emit NO_x, HAPs, and VOCs, or in some cases by electric motors that have no direct emissions.²¹

2. Dehydration and Liquids Removal

Produced natural gas is typically saturated with liquids, including water and condensable hydrocarbons. The hydrocarbon liquids can be recovered for profit, while water can create operational difficulties if it is not removed. Operators can use dehydrators to remove water from the natural gas stream in an effort to prevent liquids accumulation in process piping or damage to compressors.²² During this process, a dehydrator passes the “wet” natural gas through a lean absorbent stream, typically a glycol solution, causing the water and some heavier hydrocarbons to be absorbed into the glycol. The glycol is then regenerated by boiling the glycol to drive off the water. This process may cause the release of absorbed hydrocarbons, resulting in emissions of VOCs, HAPs and some GHGs to atmosphere. The vent streams from dehydrators can be vented to atmosphere or routed to a control device such as a condenser, flare, or vapor recovery unit.²³

There is often a small amount of crude oil or other liquid hydrocarbons associated with field gas in natural gas wells. The crude oil is separated from the field gas at the well site and transported by field lines to storage tanks before being transported to refineries.²⁴ Additionally, liquids may accumulate in gathering system lines over time. These liquids can be removed by “pigging” the line. Pigging is a process involving a plug that is forced through the line, pushing accumulated liquids ahead of it to a pig catching station where it is recovered to tankage.

²¹ See 76 Fed. Reg. at 52,745.

²² See, e.g., 76 Fed. Reg. at 52,744.

²³ See 40 C.F.R. § 63.765; accord 5 Colo. Code Regs. 1001-9, § XII.H; Wyo., *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance*, supra note 16, at 15, 20.

²⁴ 49 Fed. Reg. 2656, 2568 (Jan. 20, 1984).

3. Sweetening Units

If the natural gas is “sour” then operators can use a variety of processes to remove hydrogen sulfide (H₂S) and carbon dioxide (CO₂) impurities from the gas stream. This process typically occurs at gas processing plants and is referred to as gas “sweetening.” Sweetening typically involves passing the sour gas stream through an amine solution where the H₂S and CO₂ are preferentially absorbed. The processed natural gas is low in sulfur and CO₂, and is referred to as “sweet gas.” The amine solution containing the H₂S and CO₂ is then regenerated by boiling the amine solution, resulting in the production of a gas stream of H₂S and CO₂ called “acid gas.” Depending on the composition, the acid gas stream may be further processed for elemental sulfur recovery, vented, incinerated, or injected back into the formation.²⁵ The remaining gas is referred to as “sweet gas” and does not contain significant quantities of sulfur.

4. Pneumatic Controllers and Chemical Injection Pumps

Pneumatic controllers in the gathering facilities are generally similar to those at well sites. Also, pneumatics control valve movements at gas plants, and tend to operate using natural gas from the gas plant, or “plant air.” The controllers using plant air generally do not have any direct emissions however they may require the use of engine-driven compression to supply the compressed air. Gas plant pneumatic controllers often control gas flow within the plant, but are also often a critical control mechanism in responding to emergency conditions at these facilities.

5. Leak Detection and Repair

Operators cannot avoid occasional leaks even using best practices. Valves, pump seals, flanges and connections, and compressors at gas plants emit VOCs, HAPs, and GHGs during normal operation. The emissions from such leaks are called “fugitive” emissions and can occur at any point along the production or supply chain. These emissions can be identified visually using infrared cameras or through point-by-point sampling. To reduce fugitive emissions, various regulations and permits may require operators to implement leak detection or leak detection and repair (LDAR) programs.²⁶ Increasingly, operators (and inspectors) rely on infrared cameras to detect fugitive emissions, and in some instances inspections using the infrared cameras are mandatory.

III. EPA’s New Federal Air Regulations Governing Natural Gas Production and Hydraulic Fracturing

A. Overview

“The CAA has two federal programs that provide for emission standards to be established through technology-based requirements promulgated for industrial

²⁵ 49 Fed. Reg. at 2658.

²⁶ 40 C.F.R. §§ 60.630 to -.636, 63.769, 63.1283(c)(3); *see also Id.* §§ 60.5400 to -.5402; *accord* 5 Colo. Code Regs. 1001-9, § XII.G.1.

categories.”²⁷ First, EPA imposes performance standards on new and modified sources.²⁸ Second, EPA regulates emissions of HAPs from both new and existing sources.²⁹

1. New Source Performance Standards

In 1970, Congress enacted CAA section 111, which requires EPA to establish emission standards for new and modified stationary sources falling within particular industrial categories.³⁰ In a nutshell, Congress restructured the CAA to establish “a rigorous program for the regulation of existing and new sources of air pollution.”³¹ The new program required EPA to promulgate nationally applicable air quality standards (NAAQS) and state-adopted plans to implement those standards (SIPs).³² EPA has established NAAQS for six pollutants.³³ EPA and the states achieve the NAAQS primarily through imposing controls on new and existing sources of pollution.³⁴ With regard to “new sources,” the CAA:

contemplated that major new sources of pollution would be subject to controls *more stringent* than those needed to meet [the] NAAQS. Section 111 of the Act required the Administrator to adopt technology-based new source performance standards (NSPS) limiting the emissions from any new or modified facilities in certain industrial categories that “contributed significantly to air pollution.” Section 111(e) made it unlawful for a new source in such a category to operate in violation of any applicable NSPS regardless of whether its emissions caused [NAAQS] to be exceeded.³⁵

²⁷ Arnold W. Reitze, Jr., *The Intersection of Climate Change and Clean Air Act Stationary Source Programs*, 43 Ariz. St. L.J. 901, 920-21 (2011).

²⁸ 42 U.S.C. § 7411.

²⁹ *Id.* § 7412.

³⁰ *Id.* § 7411.

³¹ *Alabama Power Co. v. Costle*, 636 F.2d 323, 346 (D.C. Cir. 1979).

³² *Id.*

³³ 40 C.F.R. §§ 50.4 to -.17.

³⁴ *Alabama Power Co.*, 636 F.2d at 346.

³⁵ *Id.* (emphasis added).

NSPS may apply when a stationary source begins construction, reconstruction, or modification after proposed regulations are promulgated for a source category.³⁶ The CAA refers to such sources as “affected facilities.”³⁷

The NSPS can have “applicability dates” that are different from their “effective dates.”³⁸ As indicated above, “[t]he NSPS program applies to new, modified, and reconstructed facilities.”³⁹ In particular, NSPS regulations can apply to facilities that are constructed, modified, or reconstructed after the date when the regulation was originally *proposed*, as opposed to the date when the regulation became final, e.g., the publication date in the *Federal Register*. This creates a scenario in which facilities may have to comply with NSPS requirements even though those requirements were not codified at the time the facility was constructed, modified, or reconstructed.

Moreover, there is no specific emissions “threshold” in CAA Section 111.⁴⁰ Theoretically, “almost all changes to existing facilities *potentially* can trigger NSPS applicability”⁴¹ With a few exceptions, a modification requires a physical or operational change and an increase in the facility’s hourly rate of emissions for any pollutant to which a standard applies or which results in the emission of any air pollutant not previously emitted.⁴² On the other hand, while EPA may impose standards, EPA must also consider costs, non-air quality health and environmental impacts, and energy requirements when it proposes standards.⁴³

³⁶ Arnold W. Reitze, Jr., *State and Federal Command-and-Control Regulation of Emissions from Fossil-Fuel Electric Power Generating Plants*, 32 *Envtl. L.* 369, 381 (2002).

³⁷ See 40 C.F.R. § 60.2 (“Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.”); see also *id.* § 60.1(a) (“[T]he provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.”).

³⁸ See 42 U.S.C. § 7411(e).

³⁹ Reitze, Jr., *State and Federal Command-and-Control Regulation*, *supra* note 36, at 383.

⁴⁰ Reitze, Jr., *The Intersection of Climate Change*, *supra* note 27, at 921.

⁴¹ *Id.* (emphasis added).

⁴² Reitze, Jr., *State and Federal Command-and-Control Regulation*, *supra* note 36, at 383 (citing 42 U.S.C. §7411(a)(4), and 40 C.F.R. § 60.14(a)).

⁴³ Reitze, Jr., *The Intersection of Climate Change*, *supra* note 27, at 921 (citing 42 U.S.C. §7411(a)).

2. NSPS Historically Applicable to Oil and Gas Upstream and Midstream Operations

EPA proposed to create a “source category” for “crude oil and natural gas production” in 1978,⁴⁴ although it did not specifically explain how sources in that category “cause[], or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.”⁴⁵ EPA similarly finalized its determination to create NSPS for oil and gas production without comment in 1979.⁴⁶

In 1985, EPA promulgated NSPS for equipment leaks of VOCs from onshore natural gas processing plants.⁴⁷ The rules applied to “two types of ‘affected facilities,’ which include specific equipment with the potential to leak VOC. Each gas plant compressor is an affected facility. Each process unit is also an affected facility.”⁴⁸ Later that same year, EPA promulgated additional NSPS for the source category that regulates sulfur dioxide (SO₂) emissions from natural gas processing plants.⁴⁹ Other than natural gas processing plants, EPA has not previously set NSPS specifically for the oil and natural gas source category.

3. CAA-Required Review of NSPS

The CAA requires EPA to “review and, if appropriate, revise” its NSPS “at least every 8 years.”⁵⁰ According to EPA, when it performs such a revision it “has authority to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.”⁵¹

⁴⁴ 43 Fed. Reg. 38,872, 38,877 (Aug. 31, 1978).

⁴⁵ See 42 U.S.C. § 7411(b)(1)(A).

⁴⁶ 44 Fed. Reg. 49,222, 49,226 (Aug. 21, 1979).

⁴⁷ 50 Fed. Reg. 26,122, 26,124 (June 24, 1985) (codified in their current form as Subpart KKK at 40 C.F.R. §§ 60.630 to -.636).

⁴⁸ *Id.* at 26,122.

⁴⁹ 50 Fed. Reg. 40,158, 40,160 (Oct. 1, 1985) (codified in their current form as Subpart LLL at 40 C.F.R. §§ 60.640 to -.648). Operators locate sweetening units at various places in the production, gathering, and processing array, so the applicability of NSPS LLL is not strictly limited to onshore natural gas processing plants. However, operators tend to locate sweetening units at processing locations.

⁵⁰ 42 U.S.C. § 7411(b)(1)(B).

⁵¹ 77 Fed. Reg. 49,490, 49,494 (Aug. 16, 2012).

4. National Emission Standards for Hazardous Air Pollutants

The CAA also “has an extensive regulatory program to control hazardous air pollution emissions”⁵² Pursuant to the CAA, EPA must establish uniform national standards oriented toward controlling specific HAPs.⁵³ These National Emission Standards for Hazardous Air Pollutants (NESHAP) regulate HAPs from both new and existing stationary sources.⁵⁴ The goal stated in CAA Section 112 is to obtain the maximum degree of HAP reductions that is achievable after considering costs, non-air quality health and environmental impacts, and energy requirements using technology-based controls known as “maximum achievable control technology” (MACT) standards.⁵⁵

The NESHAP program primarily regulates “major stationary sources,” which the CAA defines as sources of emissions of 10 tons per year (tpy) of any HAP or 25 tpy of a combination of HAPs.⁵⁶ Congress listed several HAPs in the CAA, and then required EPA to develop a list of source categories that emit them (and other HAPs) in significant quantities.⁵⁷ EPA then develops MACT standards for new and existing sources based on the degree of emission control achievable through the application of technologies used by the best performing sources in a given category.⁵⁸ As with NSPS, EPA generally develops and implements the NESHAP and then delegates them to the states; however, even after delegating, EPA retains authority to implement and enforce the standards.⁵⁹ Upstream and midstream oil and gas operations may emit HAPs such as n-hexane, formaldehyde, and “BTEX,” i.e., benzene, toluene, ethylbenzene and xylene.⁶⁰

5. NESHAP Historically Applicable to Oil and Gas Upstream and Midstream Operations

In 1999, EPA promulgated two NESHAP (subparts HH and HHH) for the oil and natural gas industry. The emission standards in NESHAP HH apply to owners and operators of facilities that process, upgrade, or store hydrocarbon liquids to the point of custody transfer, and natural gas from the well up to and including the natural gas

⁵² Reitze, Jr., *State and Federal Command-and-Control Regulation*, *supra* note 36, at 394 (citations omitted).

⁵³ *Id.* § 7412(d).

⁵⁴ *Id.* § 7412(d)(2).

⁵⁵ Reitze, Jr., *The Intersection of Climate Change*, *supra* note 27, at 922 (citing 42 U.S.C. §7412(d)).

⁵⁶ *Id.* (citing 42 U.S.C. § 7412(a)(1)).

⁵⁷ 42 U.S.C. § 7412(c).

⁵⁸ *Id.* § 7412(d)(3), (g)(2).

⁵⁹ *Id.* § 7412(l).

⁶⁰ 76 Fed. Reg. at 52,745.

processing plant.⁶¹ The standards limit HAP emissions from process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks at natural gas processing plants. An oil or natural gas facility that is a major source of HAPs is required to, among other things: install MACT-level controls on the specified sources; demonstrate the effectiveness of such controls; continuously monitor the controls; record applicable monitoring data; and submit various notifications and reports regarding the source to assure compliance with applicable pollution control requirements.⁶²

EPA also promulgated standards applicable to natural gas transmission and storage facilities.⁶³ When EPA was developing NESHAP HH, it obtained information on glycol dehydration units indicating substantial HAP emissions from dehydrators associated with natural gas transmission and storage facilities.⁶⁴ “The information indicated that natural gas transmission and storage facilities have the potential to be major HAP sources.”⁶⁵ Accordingly, EPA included glycol dehydration units in natural gas transmission and storage when it extended the NESHAP program to upstream oil and gas activities.

6. CAA-Required Review of NESHAP

As it does with NSPS, the CAA requires EPA to “review, and revise as necessary (taking into account developments in practices, processes, and control technologies),” the NESHAP “no less often than every 8 years.”⁶⁶ This review, which is commonly called “residual risk review,” does not require EPA to recalculate the MACT upon which the then-existing standards are based. In other words, EPA does not have to start from scratch.⁶⁷

7. EPA Promulgation of New Performance Standards and Revised Emission Standards for Oil and Gas Operations

On August 16, 2012, EPA published NSPS OOOO and revised NESHAP HH and NESHAP HHH as the culmination of its reviews of standards applicable to oil and gas sources under sections 111 and 112.⁶⁸ The legal route that these regulations followed is interesting. On January 14, 2009, two “citizen groups,” WildEarth Guardians and San

⁶¹ 64 Fed. Reg. 32,610, 32,613 (June 17, 1999) (currently codified as Subpart HH at 40 C.F.R. §§ 63.760 to -.779).

⁶² 40 C.F.R. §§ 63.771 to -.775.

⁶³ 64 Fed. Reg. at 32,613 (currently codified as Subpart HHH at 40 C.F.R. §§ 63.1270 to -.1289).

⁶⁴ 64 Fed. Reg. at 32,611.

⁶⁵ *Id.*

⁶⁶ 42 U.S.C. § 7412(d)(6).

⁶⁷ *Natural Res. Def. Council v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008).

⁶⁸ 77 Fed. Reg. 49,490 (Aug. 16, 2012).

Juan Citizens Alliance, sued EPA alleging that EPA had failed to review and revise the NSPS and NESHAP for oil and natural gas production sources as required by the CAA.⁶⁹ EPA entered into a consent decree with the plaintiffs in 2010, and agreed to review and revise the regulations.⁷⁰ On August 23, 2011, EPA proposed the new and revised regulations.⁷¹ Notably, EPA also selected that date as the NSPS OOOO applicability date.⁷² While the EPA Administrator finalized the rules in April 2012, it took EPA more than four months to publish the rules in the *Federal Register*.⁷³

By publishing the final rules, EPA essentially set in motion a compliance calendar. The most important date is the rule's general "effective date" of October 15, 2012, i.e., two months after EPA published the rules. The majority of the new regulations kicked in on that date.⁷⁴ Operators particularly must focus on that date for any natural gas well hydraulic fracturing operations, gas operated pneumatics installed after August 23, 2011, and gas plant equipment leaks subject to the LDAR program.⁷⁵ Operators have a little more time before they must comply with the other requirements.

As mentioned above, one key item to keep in mind for NSPS rules is that the "applicability date" is different than the "effective date." The applicability date is the date the rule was first proposed in the *Federal Register*, which for NSPS OOOO was August 23, 2011.⁷⁶ This means that operators may have installed or modified certain equipment more than one year ago that is affected by this rule going forward.

a. New Performance Standards in Subpart OOOO

The most publicized component of EPA's August 16, 2012 rulemaking is NSPS OOOO,⁷⁷ and in particular the publicity has focused on hydraulic fracturing. There are a couple of key points to keep in mind: (1) the hydraulic fracturing segment is for natural gas wells, not oil wells⁷⁸; and (2) there are a number of other components of the new standards that will impact upstream operations.⁷⁹

⁶⁹ *Id.* at 49,496.

⁷⁰ Consent Decree, *Wildearth Guardians et al. v. Lisa P. Jackson*, 1:09-cv-00089 (CKK) (Feb 4, 2010).

⁷¹ 76 Fed. Reg. at 52,738.

⁷² *Id.* at 52,745.

⁷³ *See* 77 Fed. Reg. at 49,541.

⁷⁴ *See id.* at 49,491, 49,497 Table 3.

⁷⁵ *See id.*

⁷⁶ *Id.* at 49,493.

⁷⁷ *See* 40 C.F.R. §§ 60.5360-.5430.

⁷⁸ 77 Fed. Reg. at 49,492.

⁷⁹ *See generally id.*

As a quick summary: the NSPS, which are located at 40 C.F.R. §§ 60.5360 through -5430, and revised NESHAP, which are located at 40 C.F.R. §§ 63.760 through -779 and 40 C.F.R. §§ 63.1270 through -1289, cover various equipment and operations at well sites, gathering facilities, gas plants, natural gas transmission and compression facilities, and even underground natural gas storage. For well sites, the new rules cover certain completions, storage vessels, and pneumatics. For gathering facilities, the new rules cover certain storage vessels, pneumatics, and compressors. The new rules also cover certain storage vessels, pneumatics, and compressors at gas plants, and additionally cover LDAR and SO₂ emissions. For both natural gas transmission and compression and underground natural gas storage, the new rules cover certain glycol dehydrators and storage vessels. Operators should consider that while a large amount of the focus is on natural gas, some of the new equipment rules, such as for storage tanks, apply to both natural gas operations *and* crude oil operations.

It is also important for operators to carefully review what the “affected facility” is under each regulation. Under NSPS OOOO, there are several events that can trigger the applicability of the standards to oil and gas operations. For example, individual natural gas-driven pneumatic controllers can be affected facilities, mandating control requirements on each controller that is installed or changed out.⁸⁰ Similarly, each storage tank that emits greater than six tpy of VOCs may be an individual affected facility.⁸¹ Notably, EPA created a special definition of “modification” under the new standards for hydraulic fracturing that makes it clear that re-fracturing a well may bring it within the scope of the new requirements, regardless of how old the well is.⁸²

b. Affected Facilities under NSPS OOOO

i. Well Completions

The new performance standards generally apply to natural gas well completions and recompletions that commence after October 15, 2012.⁸³ Notably, the standards *only* apply to natural gas wells, not oil wells,⁸⁴ and define “natural gas well” as an “onshore well drilled principally for production of natural gas.”⁸⁵ Some in the industry have argued that such a distinction creates uncertainty and implementation difficulties because

⁸⁰ See 40 C.F.R. § 60.5365(d).

⁸¹ See *id.* §§ 60.5365(e), -.5395.

⁸² See *id.* § 60.5365(h)(1)-(2).

⁸³ 40 C.F.R. §§ 60.5370(a), -.5410.

⁸⁴ 77 Fed. Reg. 49,490, 49,492 (Aug. 16, 2012) (“Oil wells (wells drilled principally for the production of crude oil) are not subject to this rule.”).

⁸⁵ 40 C.F.R. § 60.5430.

it is “overly broad, unclear, and risks significant confusion about the actual scope of this rule.”⁸⁶

While the new rules *apply* to such completions beginning October 15, 2012, they require different actions for *compliance* at different times. There is a “phase-in” period for the more rigorous requirements. Prior to January 1, 2015, operators performing completions or recompletions must either (1) utilize a combustion device with continuous ignition *or* (2) perform “reduced emission completions” (REC), a.k.a. “green completions” with combustion.⁸⁷ Beginning on January 1, 2015, operators will have to perform green completions, routing all “salable quality gas” to the flow line *as soon as practicable* and combusting all gas that is not suitable for the flow line.⁸⁸

The rules also list certain types of wells that will not have to be controlled using green completions. Specifically, green completions will not be required for wildcat, delineation, and low-pressure wells.⁸⁹ For example, EPA singled out coalbed methane wells as typically low-pressure wells,⁹⁰ although they are not always low-pressure wells. Even for these wells, however, the rules require operators to use completion combustion devices.⁹¹ Moreover, some in the industry have argued that the technical derivation of what is a “low pressure gas well” published in the final rule makes too many wells in historically low-pressure fields subject to regulation, and was impermissibly withheld from industry review and comment prior to promulgation.⁹²

⁸⁶ Petition for Administrative Reconsideration by Western Energy Alliance, Letter from John R. Jacus, Counsel for the Western Energy Alliance, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency, at 8 (Oct. 15, 2012) (“Western Energy Alliance Reconsideration Letter”).

⁸⁷ 40 C.F.R. § 60.5375(a); 77 Fed. Reg. at 49,497 Table 3.

⁸⁸ 40 C.F.R. § 60.5375(a)(2). The regulations define “salable quality gas” as “natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas, regardless of whether such gas is sold.” *Id.* § 60.5430. Operators may alternatively use, inject, or re-inject non-salable gas. *Id.* § 60.5375(a)(1).

⁸⁹ *Id.* § 60.5375(f). There are additional exemptions to the green completion and combustion requirements where such controls are not feasible or safe. *Id.* § 60.5375(a)(3). For example, EPA will not require combustion “in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways.” *Id.*

⁹⁰ *E.g.*, 76 Fed. Reg. at 52,758. EPA will determine whether a well is a “low-pressure well” according whether $(0.445 \times \text{reservoir pressure (psia)}) - (0.038 \times \text{vertical well depth (feet)}) - (67.578 \text{ (psia)})$ is less than the flowline pressure at the sales meter. 40 C.F.R. § 60.5430.

⁹¹ 40 C.F.R. § 60.5375(f)(1).

⁹² *See* Petition for Administrative Reconsideration by Independent Petroleum Association of America *et al.*, Letter from James D. Elliot, Counsel for the Associations,

Operators must look closely at what is required for completions under the new rules. According to EPA, the new rules do not require capture of all gaseous emissions occurring during completions.⁹³ Rather, the capture requirement comes into play once the gas portion of the flowback “is of sufficient volume to operate a separator, which is then used to separate and recover various components of the flowback.”⁹⁴ During green completions, operators must route salable gas to a gas flow line “as soon as practicable.”⁹⁵ According to EPA, this cannot be done until *after* separation of gases from recovered liquids.⁹⁶ Consequently, the initial gas that comes to the surface during flowback is not necessarily a “flowback emission” and may not be subject to the completion combustion requirement in the new rules.⁹⁷ However, because the new rule has a “general duty clause,”⁹⁸ operators do have an ongoing obligation to “*minimize*” such releases to atmosphere even before separation.

Many existing and future natural gas wells could potentially be “affected facilities” under the new rules. It is worth noting, however, that even when fracturing or re-fracturing triggers NSPS OOOO, the compliance requirements are only triggered for the completion or recompletion itself.⁹⁹ In other words, such an operation does not necessarily trigger the performance standard requirements for other equipment at the well site. One big concern is that EPA may consider re-completions prior to 2015 to be “modifications” that trigger NSPS applicability. However, in order to encourage green completions before 2015, EPA has provided that operators will not trigger NSPS by

to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency, at 2-3 (Oct. 15, 2012) (“IPAA Reconsideration Letter”).

⁹³ See Letter from Peter Tsirigotis, *supra* note 11, at 2.

⁹⁴ *Id.*

⁹⁵ 40 C.F.R. § 60.5375(a)(2).

⁹⁶ See Letter from Peter Tsirigotis, *supra* note 11, at 2. EPA does not define the term “recovered liquids,” but has clarified that it meant the term to cover “condensate, crude oil and produced water recovered through the separation process.” *Id.* Initial flowback of such liquids can be “routed to temporary ‘fracture tanks’” or more permanent storage vessels. *Id.*

⁹⁷ According to EPA, “releases of gas or vapor during operations that occur prior to separation, such as ‘screenouts’ and ‘coil tubing cleanouts,’ are not ‘flowback emissions.’” *Id.* at 4. A “screenout” is “[a] condition that occurs [during completions and workovers] when the solids carried in a treatment fluid, such as proppant in a fracture fluid, create a bridge across the perforations or similar restricted flow area. This creates a sudden and significant restriction to fluid flow that causes a rapid rise in pump pressure.” Shlumberger Oilfield Glossary, <http://www.glossary.oilfield.slb.com/>, last visited Jan. 15, 2013. Basically, screenouts and cleanouts are used to clear sand that has plugged the wellbore, and can lead to small amounts of gas and condensate escaping the wellbore.

⁹⁸ 40 C.F.R. § 60.5375(a)(4).

⁹⁹ 77 Fed. Reg. at 49,497.

“modifying” a well during re-completion if the re-completion uses REC and combustion controls that would meet the post-2015 standards.¹⁰⁰ This may be a double-edged sword, however, because in order to avoid NSPS applicability, not only must operators use green completions and combustion controls, but also operators must meet all the post-2015 notification, recordkeeping, and reporting requirements.¹⁰¹ Accordingly, operators may question the benefit of not being considered a “modification,” and should address whether doing so results in any state-permitting benefits.

Operators may also wonder exactly *what* is a “REC” or “green completion.” EPA defines REC as:

[A] well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.¹⁰²

Operators must also either re-inject produced liquids or route them to storage vessels.¹⁰³ Interestingly, whether a completion is “green” only depends on whether it meets the definition of REC. In other words, there are no compliance standards measuring the effectiveness of a green completion. As mentioned above, however, the new regulations have a “general duty clause” specifically applicable to such completions.¹⁰⁴

EPA has also explained what counts as a “completion combustion device.” EPA defines such device as “any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.”¹⁰⁵ As with the “green completion” requirement, there are not currently any compliance standards measuring the effectiveness of a “completion combustion device.”¹⁰⁶ In other words, the new rules do not regulate such devices the way that they have historically regulated flares. As a result, it’s not immediately apparent, for example, how the use of such devices coexists with operators’ duties under the greenhouse gas reporting rule.

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

¹⁰² 40 C.F.R. § 60.5430.

¹⁰³ *Id.* § 60.5375(a)(1).

¹⁰⁴ *Id.* § 60.5375(a)(4) (“You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.”).

¹⁰⁵ *Id.* § 60.5430.

¹⁰⁶ *See Id.* §§ 60.5410, -.5415.

Before an operator completes or recompletes a natural gas well, it must submit a written or email notification to EPA.¹⁰⁷ The notification must contain the operator's contact information, API well identification number, geographic coordinates, and the planned date for commencing flowback.¹⁰⁸ The new rules require operators to submit the notification at least "two days" prior to commencing the completion or recompletion operations.¹⁰⁹ EPA has not defined exactly what it considers "two days" to be, so one option is to submit the required notice conservatively at least two business days before commencing the completion or recompletion operations. Some in the industry have argued that the two-day notice requirement "is symptomatic of the fundamental flaw in th[e] NSPS" – it forces operators to prematurely forecast the production quantity and quality from a new well and make significant resource investments based on these forecasts."¹¹⁰ If and when EPA delegates authority to implement NSPS OOOO to any state, the operator will send the notification to the state instead of EPA. For now, however, EPA has clarified that compliance with existing state notification rules satisfies the notification requirement in the new performance standards.¹¹¹

ii. Storage Vessels

A broad array of storage vessels "located in the oil and natural gas production segment, natural gas processing segment, or natural gas transmission and storage segment" may potentially be an "affected facility."¹¹² According to the rules, those vessels with VOC emissions of at least six tpy must achieve 95% reduction in VOC emissions.¹¹³ EPA has subsequently provided clarification that the six-tpy threshold is

¹⁰⁷ *Id.* § 60.5420(a)(2)(i).

¹⁰⁸ *Id.*

¹⁰⁹ *Id.*

¹¹⁰ Western Energy Alliance Reconsideration Letter, *supra* note 86, at 9.

¹¹¹ 40 C.F.R. § 60.5420(a)(2)(i).

¹¹² *Id.* § 60.5365(e). "EPA did not intend only storage vessels located at well sites to be subject to the NSPS." Letter from Peter Tsirigotis, *supra* note 11, at 5.

¹¹³ 40 C.F.R. § 60.5395(a). Notably, EPA does not consider vapor recovery units (VRUs) to be control devices. Letter from Peter Tsirigotis, *supra* note 11, at 6. However, operators can use VRUs to route emissions through a closed-vent system to a process natural gas line in furtherance of meeting the 95%-reduction standard for VOCs. *Id.*; *cf.* 40 C.F.R. § 63.766(b)(3) ("The owner or operator shall control air emissions by connecting the cover, through a closed-vent system . . . to a process natural gas line."). There is industry concern that EPA's treatment of VRUs in NSPS OOOO is more stringent than NESHAP HH and HHH. *See* Administrative Petition for Reconsideration by Gas Processors Association, Letter from Jeff Applekamp, Director, Government Affairs, Gas Processors Association, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency, at 6-7 (Oct. 16, 2012) ("GPA Reconsideration Letter").

measured *after* accounting for legal or practically enforceable controls.¹¹⁴ So, if a state has a mandatory control program, e.g., Colorado, Wyoming, and North Dakota, and that program is part of an approved SIP, then operators should measure emissions after factoring in the controls.

EPA originally proposed to determine applicability based on crude oil and condensate throughput, but comments from industry and others noted that operators could end up with heavier-material tanks with high throughput being regulated even though emissions were very minor, and EPA ultimately agreed to eliminate the throughput applicability.¹¹⁵

The new performance standards create several potential applicability dilemmas. Operators may not have records to establish when they constructed certain tanks, because they frequently keep records for well sites based on rig-up, drilling, production, etc., not based on surface site development. The new rules may not let operators avoid applicability by switching throughput from one tank to another in a tank battery in order to keep each individual tank under the applicability threshold. They also do not clarify whether operators may estimate emissions using production decline curves, which would provide more accurate estimates, or without production decline curves, which would provide inaccurate but conservative results. Meanwhile, operators may encounter difficulty obtaining the emissions control equipment necessary for compliance, particularly considering the new monitoring and manufacturer requirements.

EPA's grace periods for determining applicability also may not provide operators enough time to make meaningful determinations, and may create additional confusion. There is a one-year phase-in period for the new storage vessel performance standards.¹¹⁶ EPA also provided two additional regulatory grace periods for vessels at well sites.¹¹⁷ For vessels at new well sites, EPA has provided thirty days to determine whether the vessels will trigger the six-tpy VOC threshold, and then an additional thirty days to install and operate a control device.¹¹⁸ On the other hand, EPA has not provided the grace period for storage vessels at existing well sites, which may receive production from wells with vastly different production rates from the original wells.¹¹⁹ Also, EPA did not clarify how operators should deal with co-located wells from different formations. Accordingly, it's possible that a new co-located well accessing a different formation from an existing well pad is essentially the equivalent of a "new well site," and arguably should receive the longer compliance grace period. Similarly, EPA does not take into account declining production rates to allow for operators to remove controls when emissions drop below the applicability threshold. This could lead to unnecessary

¹¹⁴ Letter from Peter Tsirigotis, *supra* note 11, at 5.

¹¹⁵ 77 Fed. Reg. at 49,500.

¹¹⁶ 40 C.F.R. § 60.5395.

¹¹⁷ *Id.* § 60.5395(a)(1).

¹¹⁸ *Id.* § 60.5395(a)(1); 77 Fed. Reg. at 49,498.

¹¹⁹ 40 § 60.5395(a)(2).

emissions as fuel gas is continuously combusted in order to control a very small amount of VOC emissions.

There is another potential issue regarding storage tanks at well sites. Portable tanks are often used during flowback following hydraulic fracturing. EPA defined the term “storage vessel” in the rule to exclude portable tanks on site less than 180 days.¹²⁰ However, this means that EPA has extended applicability to “portable” storage vessels that remain on-site for 180 days or more. Given the continuing trend of multi-well pads, the definition of “storage vessel” has potential to include fracturing tanks. Emissions estimates for fracturing tanks are extremely difficult to calculate due to the highly variable composition and volume of the fluids contained. Additionally, these vessels are not pressure rated and cannot be safely controlled. As a result, the extension of applicability to such tanks could lead to the installation of *more* fracturing tanks and a *larger* environmental footprint in order to keep fracturing tank emissions below the control thresholds. Similarly, the definition of “storage vessel” could also apply to storage vessels with few to no emissions, such as lube oil and chemical storage tanks and require that emission calculations be submitted to EPA.

Moreover, EPA has included NESHAP-type control device monitoring and testing requirements in the rule.¹²¹ These requirements may be costly, and in many cases operators may not be able to achieve compliance. This sample of potential applicability and compliance issues attributable only to *storage vessels* indicates that EPA and the states may ultimately establish guidance for the industry.

iii. Pneumatic Controllers

Operators must reduce emissions of every single continuous-bleed, natural gas-driver pneumatic controller that “commenced construction” after August 23, 2011, and emits at least six scfh by October 15, 2013.¹²² For pneumatics at gas plants, EPA is imposing a zero-bleed limit.¹²³ All other “affected” pneumatic controllers must have a bleed rate less than or equal to six scfh.¹²⁴ Operators must tag affected pneumatics with the installation date and identification information.¹²⁵

EPA created an exemption to these bleed limits if a higher-bleed-rate controller is “required based on functional needs,” which include response time, safety, and positive actuation.¹²⁶ Operators demonstrate initial compliance by submitting an initial annual

¹²⁰ *Id.* § 60.5430.

¹²¹ *See id.* § 60.5417.

¹²² *Id.* §§ 60.5365(d), -5390(c)(1).

¹²³ *Id.* § 60.5390(b)(1).

¹²⁴ *Id.* § 60.5390(c)(1).

¹²⁵ *Id.* § 60.5390(b)(2), (c)(2).

¹²⁶ *Id.* § 60.5390(a).

report listing *all* of the zero-bleed-rate controllers at natural gas processing plant and *all* of the less-than-or-equal-to-six-scfh-bleed-rate controllers located between the wellhead and a natural gas processing plant.¹²⁷ Operators will show continuous compliance by operating the controllers continuously, submitting annual reports, and maintaining records.¹²⁸ In reality, by narrowing the “affected facility” definition to exclude low-bleed controllers (except at processing plants), EPA made it possible for operators who install such low-bleed controllers prior to the effective date to avoid the significant burdens of compliance with the NSPS.

iv. Compressors

The new performance standards regulate VOC emissions from reciprocating compressors powered by reciprocating spark ignition engines and from centrifugal compressors powered by turbines.¹²⁹ Operators trigger NSPS by “commenc[ing] construction” when they install compressors, not when they relocated them within their operations.¹³⁰ So, the NSPS are only applicable to compressors *installed* after August 23, 2011.

EPA originally proposed to require the use of dry seals on all centrifugal compressors. But, after receiving comments questioning the technical feasibility of using dry seals on certain regulated equipment, EPA is also allowing the use of wet seals.¹³¹ This means that EPA generally does not regulate centrifugal compressors with dry seals under NSPS OOOO.¹³² However, if an operator chooses to use wet seals, EPA requires the operator to capture the emissions and route them to a control device that achieves a 95% reduction of VOCs.¹³³

For reciprocating compressors, the new performance standards require replacement of rod packing systems either every 26,000 hours of operation or every 36 months.¹³⁴ The rule appears to require that operators start counting hours and months from the effective date of the rule, and not from the August 23, 2011 applicability date.

¹²⁷ *Id.* § 60.5410(d)(2)-(3), (5).

¹²⁸ *Id.* § 60.5415(d).

¹²⁹ *Id.* §§ 60.5380, -.5385.

¹³⁰ 77 Fed. Reg. at 49,523-24 (“The NSPS also does not apply to relocated compressors. As provided in the NSPS General Provisions at 40 CFR 60.14(e)(6), relocation of an existing facility is not modification.”).

¹³¹ *Id.* at 49,499-500, 49,523.

¹³² *See* 40 C.F.R. § 60.5365(b).

¹³³ *Id.* § 60.5380(a)(1).

¹³⁴ *Id.* §§ 60.5385(a), -.5415(c)(3).

v. Leak Detection and Repair

In the new NSPS OOOO, EPA revised the LDAR requirements by lowering the definition of “leak” in newly constructed or modified gas plants from 10,000 ppm to 500 ppm.¹³⁵ These equipment leak provisions apply only at onshore gas processing plants, not to storage vessels, compressors, completions, etc.¹³⁶ The new definition applies to new, reconstructed, or modified equipment in a process unit, other than compressors, in VOC or “wet gas service.”¹³⁷ A piece of equipment is “in wet gas service” if it “contains or contacts the field gas before the extraction step at a gas processing plant process unit.”¹³⁸ EPA also defines “gas processing plant process unit” as

[E]quipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.¹³⁹

Historically, some operators may not have defined their “gas processing plant process units” in this manner. It is important to ensure that this definition is considered in the facilities’ LDAR programs, as regulatory agency inspectors have been focusing on this issue recently.

Under the new standards, EPA will presume that every piece of equipment at a gas plant is “in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is *not* in VOC service or wet gas service.”¹⁴⁰ Such equipment must meet the requirements of specified sections of NSPS VVa,¹⁴¹ including the above-mentioned valve leak rate, annual connector monitoring, and additional monitoring of pumps, pressure-relief devices, and open-ended valves and lines.¹⁴² Sampling connection systems are exempted from the rule.¹⁴³

EPA’s promulgation of NSPS OOOO also limits the applicability of NSPS KKK. That subpart now only applies to affected facilities constructed between January 20,

¹³⁵ *Id.* § 60.5401(b)(2).

¹³⁶ Letter from Peter Tsirigotis, *supra* note 11, at 7.

¹³⁷ 40 C.F.R. §§ 60.5400(f), .5430.

¹³⁸ *Id.* § 60.5430.

¹³⁹ *Id.*

¹⁴⁰ *Id.* § 60.5400(f) (emphasis added).

¹⁴¹ *See generally id.* § 60.5400.

¹⁴² *See id.* § 60.5430.

¹⁴³ *Id.* § 60.5401(c).

1984, and August 23, 2011.¹⁴⁴ As a result, if an operator has modified or reconstructed a process unit at its site after August 2011, then the operator should look at such projects and consider whether it may have triggered the new performance standard requirements, including the more stringent “leak” definition.

vi. SO₂ Emissions

EPA effectively incorporated NSPS LLL into the new NSPS OOOO.¹⁴⁵ The SO₂ emission reduction requirement varies based on sulfur feed rate and the sulfur content of the acid gas, and requires a minimum SO₂ reduction efficiency of 99.9% for newly constructed or modified gas plants with sweetening units that process a sulfur feed rate of at least five long-tons-per-day with H₂S content of at least 50%.¹⁴⁶ Under the new rules, each onshore sweetening unit that processes natural gas is an affected facility.¹⁴⁷ The new standards also require detailed performance test measures,¹⁴⁸ and require measurement of daily sulfur accumulation, daily acid gas H₂S concentration, and continuous acid gas flow.

c. Revised Emission Standards in Subparts HH and HHH

When it promulgated NSPS OOOO, EPA also amended existing HAP regulations applicable to the oil and gas production sector.¹⁴⁹ The two NESHAP rules primarily affect natural gas treatment facilities. Operators likely already know if they have the types of facilities covered by these rules. New “affected source” gas plants, where operators have commenced construction on or after August 23, 2011, must comply with the NESHAP revisions starting October 15, 2012, while existing gas plants must comply by October 15, 2013.¹⁵⁰

i. Small Glycol Dehydrators

The biggest new feature of Subpart HH is that the rules address much smaller glycol dehydrator units than before.¹⁵¹ Essentially, EPA created a “small glycol dehydrators” category, which it defines as units with actual annual average natural gas

¹⁴⁴ 77 Fed. Reg. at 49,542 (revising the heading and applicability provisions for NSPS KKK).

¹⁴⁵ *Id.* at 49,498 (“The final rule incorporates the provisions of 40 CFR part 60, subpart LLL into 40 CFR part 60, subpart OOOO, and minor revisions were made to adapt the subpart LLL language to subpart OOOO.”).

¹⁴⁶ 40 C.F.R. pt. 60, subpt. OOOO Tables 1 and 2.

¹⁴⁷ *Id.* § 60.5365(g).

¹⁴⁸ *Id.* § 60.5406.

¹⁴⁹ 77 Fed. Reg. at 49,568-81 (codified as 40 C.F.R. §§ 63.760 to -.775).

¹⁵⁰ *Id.* at 49,503.

¹⁵¹ *Id.* at 49,568-81 (codified as 40 C.F.R. §§ 63.760, -.761, -.765).

flow rate less than 85,000 scm/day, which is roughly 3 mmscf/day, or actual annual average benzene emissions less than 0.9 MG/year.¹⁵² EPA will only regulate this new category of small glycol dehydrators at major sources of HAPs.

EPA made similar revisions in NESHAP Subpart HHH for natural gas transmission and storage facilities. The “small glycol dehydrators” category in gas transmission operations consists of dehydrators with *actual* annual average natural gas flow rate less than 283,000 scm/day, which is roughly 10 mmscf/day, or *actual* annual average benzene emissions less than 0.9 MG/year.¹⁵³ As with upstream small glycol dehydrators, the revised category in NESHAP HHH only applies to small dehydrators at major sources of HAPs.¹⁵⁴

ii. Storage Vessels

A few notes also stand out pertaining to EPA’s revision to NESHAP for storage vessels. As with the new NSPS rules, EPA originally proposed to broaden the applicability of the emission standards for storage tanks, potentially subjecting thousands of additional crude oil and condensate vessels to stringent emissions limits. EPA ultimately did not expand the universe of storage tanks subject to regulation under the HAP program.¹⁵⁵ EPA also changed the term “associated equipment” to exclude all storage vessels, not just those with flash emissions potential.¹⁵⁶ In NESHAP HH, emissions from “associated equipment” are *not* aggregated when making a “major source” determination.¹⁵⁷ The result of removing storage vessels with potential for flash emissions *out* of the definition of “associated equipment” is that operators must now include such emissions when making “major source” determinations.

iii. Flares

EPA’s revised emission standards also define “flare” for the first time.¹⁵⁸ This change relates to whether an operator must conduct performance testing on a control device. The control requirements in emission standards authorize owners and operators of affected sources at oil and gas production facilities to utilize: an “enclosed combustion device”; or a “vapor recovery device”; or a “flare that is designed and operated in

¹⁵² 40 C.F.R. § 63.761.

¹⁵³ *Id.* § 63.1271.

¹⁵⁴ *Id.* § 63.1270(d)(3)-(4).

¹⁵⁵ 77 Fed. Reg. at 49,532-33.

¹⁵⁶ *Id.* at 49,501 (codified as 40 C.F.R. § 63.761).

¹⁵⁷ *See* 40 C.F.R. § 63.761; 77 Fed. Reg. at 49,530 (“CAA section 112(n)(4)(A) prohibits aggregation of emissions from any oil and gas exploration or production wells (with their associated equipment) in determining major source status or for any purpose under CAA section 112.”).

¹⁵⁸ *Id.* at 49,569 (codified as 40 C.F.R. § 63.761).

accordance with the requirements § 63.11(b).”¹⁵⁹ Performance testing is not required on those devices that qualify as a “flare.”¹⁶⁰ However, Subpart HH has not previously defined “flare.” Operators have questioned whether to subject a device to performance testing, or whether the operator could show compliance by meeting the design criteria. The new rules now explicitly define a “flare” as “a thermal oxidation system using an open flame (i.e., without enclosure).”¹⁶¹ Therefore, only devices meeting this definition can avoid the more stringent compliance requirements in the regulation. For other control equipment, the revised emission standards require performance testing or manufacturer guarantees.¹⁶²

iv. Leak Detection and Repair

As it did with NSPS OOOO, EPA tightened the “leak” definition for valves subject to NESHAP HH to 500 ppm.¹⁶³ For other components, however, EPA did not change the definition of leak.¹⁶⁴

v. Additional Requirements

For the revised NESHAP, EPA is requiring operators of existing small glycol dehydration units to submit initial notification of their compliance status either within one year of becoming subject to the regulation or October 15, 2013, whichever is later.¹⁶⁵ Operators’ submissions also must include performance test results for the manufacturer-tested control device, the predetermined carbon replacement schedule for carbon absorbers (if applicable), and data related to the manufacturer performance test when compliance is based on those tests.¹⁶⁶ EPA is also requiring periodic reports that include records of carbon replacement schedules and each carbon replacement for carbon absorbers, and records of visible emissions readings exceeding the allowable duration.¹⁶⁷ Operators must keep records of their control device flow rate calculations, and report any periods when the flow rate exceeds manufacture’s performance test.¹⁶⁸ They must also

¹⁵⁹ 40 C.F.R. § 63.771(d)(1).

¹⁶⁰ *Id.* § 63.772(e)(1)(i).

¹⁶¹ 77 Fed. Reg. at 49,569 (codified as 40 C.F.R. § 63.761).

¹⁶² *Id.* at 49,573-74 (codified as 40 C.F.R. § 63.772(e)).

¹⁶³ 40 C.F.R. § 63.769(c).

¹⁶⁴ *See* 77 Fed. Reg. at 49,502 (“[W]e are revising the leak definition for valves to 500 ppm, thus requiring the application of the LDAR requirement at this lower detection level. This leak definition applies only to valves at natural gas processing plants, and not other components.”).

¹⁶⁵ 40 C.F.R. § 63.775(b)(1)(ii).

¹⁶⁶ 77 Fed. Reg. at 49,509-10; *see also* 40 C.F.R. § 63.775(b).

¹⁶⁷ *Id.*

¹⁶⁸ 40 C.F.R. §§ 63.774(h)(1), -.775.

keep records of periods when the pilot flame is absent.¹⁶⁹ For malfunctions, operators must keep records of occurrence and duration of each operational malfunction of air pollution control and monitoring equipment, as well as a description of actions taken during the malfunction to minimize emissions.¹⁷⁰ They must also keep records of the date of each semi-annual maintenance inspection.¹⁷¹

8. EPA Expansion of Regulatory Scope

EPA's new and revised regulations substantially broadened the scope of operations and emission points covered by the NSPS and MACT. Historically, EPA only really regulated onshore natural gas processing facilities through its LDAR and sweetening unit rules in NSPS KKK and NSPS LLL.¹⁷² Under NSPS OOOO, however, the list of "affected facilities" subject to NSPS includes gas well completions, storage vessels, and pneumatics at onshore oil (for storage vessels) and gas production locations; storage vessels, pneumatics, and compressors at gathering booster stations; the same sources in addition to tighter LDAR and sweetening unit standards at onshore natural gas processing locations; and storage vessels at onshore natural gas transmission compression and underground natural gas storage locations.¹⁷³ Under the NESHAP program, EPA extended regulation to new categories of "small glycol dehydrators."¹⁷⁴

Not only did EPA expand its alleged authority to new equipment and operations in the oil and gas patch, but also it likely took a step toward expanding its alleged authority to regulate methane emissions as greenhouse gases. In 2007, the Supreme Court decided that greenhouse gases are "air pollutants" as that term is used in the CAA.¹⁷⁵ After taking several regulatory steps,¹⁷⁶ EPA promulgated the "Greenhouse Gas Tailoring Rule" to regulate emissions of greenhouse gases through preconstruction and

¹⁶⁹ 77 Fed. Reg. at 49,509.

¹⁷⁰ *Id.*

¹⁷¹ 40 C.F.R. § 63.774(g).

¹⁷² *Id.* §§ 60.630(a)(1) (applicability of NSPS KKK to onshore natural gas processing plants), .640(a), (c) (applicability of NSPS LLL to "each sweetening unit, and each sweetening unit followed by a sulfur recovery unit").

¹⁷³ *See generally id.* § 60.5365.

¹⁷⁴ 77 Fed. Reg. at 49,492 ("In this final rule, we also have established MACT standards for 'small' glycol dehydration units, which were unregulated under the initial NESHAP.").

¹⁷⁵ *Massachusetts v. EPA*, 549 U.S. 497 (2007).

¹⁷⁶ 75 Fed. Reg. 25,324 (May 7, 2010) (adopting rules that require a reduction in emissions of greenhouse gases from motor vehicles); 74 Fed. Reg. 66,496 (Dec. 15, 2009) (finding that emissions of carbon dioxide (CO₂), methane (CH₄), and several other greenhouse gases present an endangerment to public health and the environment).

operating permits.¹⁷⁷ On June 26, 2012, the D.C. Circuit upheld EPA's rules relating to emissions of greenhouse gases from stationary sources.¹⁷⁸ Oil and gas upstream activities, such as an exploration and production facilities consisting of several wells and associated separators and storage tanks, may emit greenhouse gases at levels in excess of the permitting thresholds.¹⁷⁹ Accordingly, the court's decision to uphold EPA's various greenhouse gas rulemakings may ultimately impact operators nationwide.

In 2010, EPA also adopted rules requiring the annual reporting of greenhouse gas emissions from onshore oil and gas production facilities.¹⁸⁰ The Mandatory Reporting Rule (MRR) requires petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide equivalent (CO₂e) per year to report annual methane (CH₄) and CO₂ emissions from equipment leaks and venting, and emissions of CO₂, CH₄, and nitrous oxide from gas flaring and from onshore petroleum and natural gas emissions sources.¹⁸¹ Stakeholders have recently questioned the research supporting EPA's estimates of emissions from upstream natural gas production.¹⁸²

In NSPS OOOO, EPA uses methane emissions as a proxy for measuring VOCs.¹⁸³ After proposing this proxy measurement, EPA received many comments stating essentially that the proposal impermissibly expands EPA's regulatory authority to methane.¹⁸⁴ EPA denied that its use of methane as a "proxy" for VOC amounted to

¹⁷⁷ 75 Fed. Reg. 31,514 (June 3, 2010).

¹⁷⁸ *Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 116, 149 (D.C. Cir. 2012) (consolidating and dismissing various challenges to the Timing and Tailoring Rules for lack of standing because petitioners have not suffered injuries-in-fact). The D.C. Circuit subsequently denied rehearing the greenhouse gas case *en banc*. *Coalition for Responsible Regulation, Inc. v. EPA*, 09-1322, 2012 WL 6621785, at *1 (D.C. Cir. Dec. 20, 2012). The denial of rehearing drew two vigorous dissents, *see id.* at *3 (Brown, C.J., dissenting from the denial of rehearing *en banc*), and *14 (Kavanaugh, C.J., dissenting from the denial of rehearing *en banc*), and may ultimately result in appeal to the U.S. Supreme Court. As of the submission of this paper, the authors are not aware of any such appeal.

¹⁷⁹ *E.g.*, Letter from Callie A. Videtich, Acting Assistant Regional Administrator, Office of Partnerships and Regulatory Assistance, EPA Region 8, to Mr. A. Dewey Cooper, HES Professional, Bakken Operations, at Encl. 4-5 (Apr. 19, 2012).

¹⁸⁰ 75 Fed. Reg. 74,458 (Nov. 30, 2010).

¹⁸¹ *Id.* at 74,490.

¹⁸² *See American Petroleum Inst. & America's Natural Gas Alliance, Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production (Final Report) (June 1, 2012).*

¹⁸³ *E.g.*, 40 C.F.R. § 60.5390(a)-(b) (applying standards to pneumatic controllers based on those controllers' natural gas bleed rates).

¹⁸⁴ EPA, Office of Air Quality Planning and Standards, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air

“regulation” of methane, and did not change the provision in its final rules.¹⁸⁵ Nevertheless, in light of the combined Tailoring Rule, MRR, and “regulation” of methane as a surrogate for VOC, EPA appears to be building a framework for direct regulation of methane emissions from oil and gas operations. At the very least, EPA has potentially cleared a path for environmental groups to sue for a methane emission standard. In fact, seven states recently sent EPA a Notice of Intent to Sue demanding that EPA establish NSPS for methane emissions from oil and gas operations.¹⁸⁶

B. Challenges Posed by EPA’s New and Revised Rules

1. EPA’s One-Size-Fits-All Approach

Every oil and gas resource is different, and every well site, hydraulic fracturing completion, and other operation is unique. Yet, in its new rules, EPA has attempted to craft a one-size-fits-all approach to oil and gas regulation under the CAA. Some in the industry have expressed concern that doing so “will disproportionately impact smaller natural gas producers across the country.”¹⁸⁷ Regressive impacts aside, the reality of the oil and gas industry is that the operations, strategies, and techniques that work in one basin may not work in another basin.¹⁸⁸ It may be more appropriate for states to regulate oil and gas development based on locality-specific principles that make sense for operations in a given geographic and geologic area. State primacy is consistent with the CAA. As noted above, the CAA gives the states primary responsibility to achieve air quality standards through SIPs.¹⁸⁹ Most CAA permitting is done at the state level. While federal standards, such as NSPS and NESHAP, tend to have talismanic influence because the states incorporate them by reference, states have historically (and recently) responded to oil and gas development by creating extensive regulatory initiatives of their own, based on regional air quality conditions and oil and gas development-specific refinement of

Pollutants Reviews, 40 CFR Parts 60 and 63, Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738), at 415-16, 419-20 (2012) (responding to comments on the newly promulgated NSPS OOOO alleging that EPA’s requirement to measure natural gas emissions as a surrogate for VOC emissions is actually direct, unauthorized regulation of methane, i.e., greenhouse gases).

¹⁸⁵ See, e.g., 77 Fed. Reg. at 49,513 (“We consider natural gas to be an appropriate surrogate for VOC The inclusion of natural gas . . . was not an indication that EPA was proposing natural gas as a pollutant to be regulated, as some commenters mistakenly thought.”).

¹⁸⁶ Letter from Eric T. Schneiderman, Attorney General, New York, et al., to Lisa P. Jackson, Administrator, Environmental Protection Agency (Dec. 11, 2012).

¹⁸⁷ IPAA Reconsideration Letter, *supra* note 92, at 4.

¹⁸⁸ See Western Energy Alliance Reconsideration Letter, *supra* note 86, at 9.

¹⁸⁹ 42 U.S.C. § 7407; James E. McCarthy et al., Cong. Research Serv., RL30853, “Clean Air Act: A Summary of the Act and Its Major Requirements,” at 3–4 (2011).

long-standing permitting regimes.¹⁹⁰ These state programs tend to offer operators the sort of flexibility and streamlining that make operations subject to responsible regulation feasible, and enable the public-private partnership to flourish along pragmatic, mutually beneficial lines. Accordingly, some in the industry are concerned that EPA has shifted this intricate balance out of whack.

2. Operating Permits

In 1990, Congress enacted “Title V” of the CAA, which requires “major sources” of pollutants to obtain operating permits from EPA-approved state-run permitting programs.¹⁹¹ The state “operating permits” must include enforceable emission limits, compliance schedules, and monitoring, reporting, and recordkeeping requirements.¹⁹² An operating permit is “a source-specific bible for Clean Air Act compliance” containing all requirements relevant to a pollution source in a single file.¹⁹³ Accordingly, an operating permit will specify the operations allowed, the source’s emission limits, and the testing, monitoring, recordkeeping, and reporting requirements that assure ongoing compliance with the applicable regulations. Title V does not itself impose additional substantive emissions limits,¹⁹⁴ although regulators can impose additional monitoring in a Title V permit.

Title V allows both EPA and public review of permits.¹⁹⁵ After a permitting authority receives an application for a Title V permit, it must submit a copy of the application and the draft permit to EPA,¹⁹⁶ and provide the public with notice and opportunity to comment on the draft permit.¹⁹⁷ At that point, either the EPA Administrator can object to issuance of the permit, or any other person can ask the

¹⁹⁰ See generally, e.g., Lee Gribovicz, Western Regional Air Partnership, “Analysis of States’ and EPA Oil & Gas Air Emissions Control Requirements for Selected Basins in the Western United States,” at 19–22 (Nov. 28, 2011; errata corrections Jan. 8, 2012).

¹⁹¹ Clean Air Act Amendments of 1990, Pub. L. No. 101-549, §§ 501-07, 104 Stat. 2399, 2635-48 (1990) (codified as 42 U.S.C. §§ 7661-7661f); see generally *MacClarence v. EPA*, 596 F.3d 1123, 1125-26 (9th Cir. 2010).

¹⁹² 42 U.S.C. § 7661c(a).

¹⁹³ *North Carolina ex rel. Cooper v. TVA*, 615 F.3d 291, 299 (4th Cir. 2010) (citing *Virginia v. Browner*, 80 F.3d 869, 873 (4th Cir. 1996)).

¹⁹⁴ 40 C.F.R. § 70.1(b). However, EPA Region 8 utilized Title V permitting for ten years as a mechanism for creating “synthetic minor” limitations for certain oil and gas facilities in Indian country.

¹⁹⁵ 42 U.S.C. § 7661d; 40 C.F.R. § 70.8(d).

¹⁹⁶ 42 U.S.C. § 7661d(a)(1)(B).

¹⁹⁷ 40 C.F.R. § 70.7(h).

Administrator to object.¹⁹⁸ If the Administrator objects to issuance of the draft permit, then the permitting authority may not issue the permit until revising it to meet the objection.¹⁹⁹ Opponents of oil and gas development projects frequently use the Title V comment period and related appeal rights to object to permits, with increasing success.²⁰⁰

In proposing the new rules, EPA specifically provided that triggering NSPS OOOO will not, by itself, trigger the need for facilities to obtain a Title V operating permit.²⁰¹ According to EPA:

The proposed rules do not change the Federal requirements for determining whether oil and gas sources are major sources for purposes of nonattainment major New Source Review (NSR), prevention of significant deterioration, CAA title V, or HAP major sources pursuant to CAA section 112. Specifically, if an owner or operator is not currently required to get a major NSR or title V permit for oil and gas sources, including well completions, it would not be required to get a major NSR or title V permit as a result of these proposed standards.²⁰²

Nevertheless, operators must review state permitting requirements closely. While NSPS OOOO may not trigger permitting requirements by EPA fiat, it is still possible that state environmental agencies can require permits for operations and equipment brought into regulation by the new EPA rules. EPA acknowledged the potential for state permitting impacts in the publication of the final rules.²⁰³

¹⁹⁸ 42 U.S.C. § 7661d(b)(1), (2). The petition must be based on objections that were made with reasonable specificity during the public comment period on the draft permit. *Id.*

¹⁹⁹ *Id.* § 7661d(b)(3), (c).

²⁰⁰ *See, e.g.*, Order Granting Petition for Objection to Permit, In re Williams Four Corners, LLC, Sims Mesa CDP Compressor Station, EPA Pet. No. VI-2011-__ (July 29, 2011) (EPA permit decision addressing multiple challenges grounded in different aspects of the Clean Air Act).

²⁰¹ 76 Fed. Reg. at 52,751.

²⁰² *Id.*

²⁰³ *See, e.g.*, 77 Fed. Reg. at 49,513:

We are providing the . . . exception discussed above to provide states with flexibility in application of their permitting authority and resources. Commenters pointed out that a number of state permitting programs are triggered for sources that are subject to an NSPS as a result of a modification. The EPA recognizes that states are the most appropriate entities to determine whether and how sources

3. Startup, Shutdown, and Malfunction

Some equipment cannot meet emission standards during “cold starts” or during shutdown periods.²⁰⁴ Regulators recognize that even the best operated equipment can occasionally malfunction, causing excess emissions. Accordingly, EPA historically exempted excess emissions during startup, shutdown, and malfunction (SSM) events from compliance determinations, provided that the operator met certain conditions. However, in 2008, a federal court vacated the SSM exemption for the purposes of the NESHAP program.²⁰⁵ As a result, EPA has eliminated the SSM exemption for both NSPS OOOO and NESHAP HH and HHH.²⁰⁶ Instead of providing an exemption from liability for violating the performance and emission standards during periods of SSM, EPA added an affirmative defense to civil penalties (but not injunctive relief) in the performance and emission standards for malfunction-based violations.²⁰⁷ EPA contends that states cannot enact blanket SSM exemptions in their SIPs.²⁰⁸ While some states have revised their implementation plans to eliminate the liability exemption,²⁰⁹ other states have not.²¹⁰ EPA has challenged these exemptions by notifying such states that their SIPs are invalid.²¹¹

In evaluating whether oil and gas facilities have deviated from emission limits, operators must ascertain the status of the SSM exemption in applicable federal and state regulations. Essentially, the revision to the federal rules means that the same requirements apply during startup and shutdown as during normal operations. Emissions

should be permitted, and we have concern regarding potential impacts of this final rule on states’ permitting resources. Accordingly, with this final rule, we intend that states retain the discretion to determine whether refracturing activities by sources employing control techniques that are required for new wells will require changes in that source’s permit status.

²⁰⁴ See 75 Fed. Reg. 9448, 9656-57 (Mar. 3, 2000).

²⁰⁵ *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008) (vacating the General Provision, 40 C.F.R. § 63.6, which, when incorporated into specific NESHAP, exempted sources from those regulations during periods of SSM).

²⁰⁶ 77 Fed. Reg. 49,508-09, 49,557-58, 49,569-70 (to be codified at 40 C.F.R. §§ 60.5415(h), 63.762).

²⁰⁷ *Id.*

²⁰⁸ See Memorandum from John B. Rasnic, Director, Stationary Source Compliance Div., EPA Office of Air Quality Planning & Standards, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Div., EPA Region 1 (Jan. 28, 1993).

²⁰⁹ *E.g.*, 5 Colo. Code Regs. 1001-2, Common Provisions § II.E, II.J.

²¹⁰ *E.g.*, Utah Admin. Code r. 307-107.

²¹¹ *E.g.*, 76 Fed. Reg. 21,639, 21,641 (Apr. 18, 2011) (Utah SIP Call).

during malfunctions, which are sudden, infrequent, and not reasonably preventable failures, can still be excluded from operating requirements if they meet the elements of the affirmative defense, which may include: unavoidable failure of equipment, inability to prevent the malfunction through a better design or operation, no recurring pattern, expeditious repair, minimization of emissions and health impacts, and root cause analysis to correct the problem.

The SSM issue is also becoming the subject of permitting disputes based on whether operators have properly calculated emissions. Environmental groups contend that operators must include SSM emissions when calculating “potential to emit” (PTE) under permit programs. However, in 2011, the Wyoming Supreme Court disagreed.²¹² The Court ruled that when calculating PTE, regulators should not include potential emissions due to cold starts and malfunctions, because those events do not represent the intended operation of the facility.²¹³ Rather, PTE includes only emissions that occur during normal operations.²¹⁴ Nevertheless, some in the industry have argued that the new rules “effectively treat[] malfunction emissions as ‘normal’ emissions, despite their unforeseeability.”²¹⁵ Such a rule does not appropriately balance reasonable emission expectations with the reality that operators truly cannot plan for some “malfunction” events.

4. Recordkeeping and Reporting

There are also significant recordkeeping and reporting burdens that come with the new and revised rules that have generally not been discussed in the press, but will absolutely affect how operators manage their compliance programs. The details are significant, and the specific requirements are complicated, so this paper only provides a brief overview. One notable example is the new hybrid recordkeeping and reporting requirement for natural gas well completions. For natural gas wells, operators must keep daily well-completion records and submit an annual report.²¹⁶ There are two different types of annual report for completions, and the operator can choose which one to submit. The “standard” annual report must contain copies of well completion records for each well completed during the reporting period, and a “self-certification.”²¹⁷ Alternatively, EPA has created a “streamlined” reporting option, in which the operator must submit a list of all gas wells completed during the reporting period along with photographs of green completions in-progress at each well along with a self-certification of

²¹² *Sierra Club v. Wyoming Dep’t of Env’tl. Quality*, 251 P.3d 310, 313-14 (Wyo. 2011).

²¹³ *Id.* at 315.

²¹⁴ *Id.* at 314-15.

²¹⁵ Western Energy Alliance Reconsideration Letter, *supra* note 86, at 9.

²¹⁶ 40 C.F.R. §§ 60.5375(b), .5420(b).

²¹⁷ *Id.* § 60.5420(b)(2)(i). The “self-certification” is a new wrinkle in the EPA standards applicable to oil and gas operations. *See id.* § 60.5420(b)(1)(iv).

compliance.²¹⁸ The operator must keep electronic copies of the photographs containing time and date and geographic coordinates stamps.²¹⁹

The new requirements for well completions mark a deviation from the general recordkeeping and reporting requirements found in the “General Provisions” of NSPS A. Subpart A requires all owners or operators subject to NSPS to furnish written notice of, among other things, construction and initial performance testing for various affected facilities.²²⁰ EPA granted relief from NSPS A not only for well completions, but also for compressors, pneumatic controllers, and storage vessels.²²¹ That being said, the recordkeeping and reporting requirements both under NSPS A and NSPS OOOO are fairly extensive. Moreover, NSPS OOOO imposes the new self-certification requirement mentioned above.²²² Under that requirement, a senior “responsible official,” must certify to the truth, accuracy, and completeness of the various reports submitted under the new rules.²²³ The rules define the term “responsible official,”²²⁴ and such official will generally be a vice president. Some in the industry have argued that EPA impermissibly included the self-certification requirement without providing industry with an opportunity to comment.²²⁵

C. Legal Challenges to EPA’s New Regulations

Immediately after EPA published the new and revised rules in the *Federal Register*, the American Petroleum Institute (API) and other groups sought

²¹⁸ *Id.* § 60.5420(b)(2)(i), (c)(1)(v); *see also* 77 Fed. Reg. at 49,499, 49,527 (explaining the alternative requirement). “Section 60.5420(c)(1)(v) refers to 60.5420(a)(4), which specifies the records of the digital photographs to be reported in lieu of the standard annual reporting requirements. The digital photograph recordkeeping requirements in section 60.5410(a)(4) were meant to apply only in cases where the owner or operator chooses to take advantage of the streamlined alternative annual reporting option.” Letter from Peter Tsirigotis, *supra* note 11, at 3. Operators should take such photographs from “a safe distance from the wellhead,” and favor safety over pinpoint geographic accuracy. *See id.*

²¹⁹ *Id.* § 60.5420(c).

²²⁰ 40 C.F.R. § 60.7(a)(1), (6)-(7), (f).

²²¹ *Id.* § 60.5420(a)(1).

²²² *E.g., id.* § 60.5420(b)(1)(iv).

²²³ *Id.*

²²⁴ *Id.* § 60.5430.

²²⁵ *E.g.,* Petition for Reconsideration by Texas Oil & Gas Association, Letter from Shannon S. Broome, Counsel for the Texas Oil & Gas Association, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency, at 20-21 (Oct. 15, 2012).

reconsideration.²²⁶ Subsequently, at least nine Petitions for Review have been filed in the D.C. Circuit.²²⁷ Collectively, those petitions raise more allegations of error than can reasonably be covered by this paper. Several of the arguments have been addressed in the discussions of the new standards above. Generally, the challenges include the following, non-exhaustive, list of issues:

- EPA made errors in the final rule based on its flip-flopping on whether to keep certain provisions;²²⁸
- EPA failed to submit certain portions of the final rule to industry for public comment;²²⁹
- The rules have a disproportionate impact on smaller producers;²³⁰
- The purported need for the new rules is illusory because it is based on an overestimation of emissions from oil and gas operations;²³¹
- Similarly, EPA's cost-benefit analysis is based on flawed data and incorrect assumptions;²³²
- The final rule imposes costly, inflexible requirements with little, if any, corresponding environmental benefit;²³³

²²⁶ *E.g.*, Letter from Howard J. Feldman, Director, Regulatory & Scientific Affairs, American Petroleum Institute, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency (Aug. 16, 2012).

²²⁷ *Gas Processors Ass'n v. EPA*, No. 12-1406 (D.C. Cir. Oct. 15, 2012); *Domestic Energy Producers v. EPA*, No. 12-1407 (D.C. Cir. Oct. 15, 2012); *Independent Petroleum Ass'n of America v. EPA*, No. 12-1408 (D.C. Cir. Oct. 15, 2012); *Natural Resources Defense Council v. EPA*, No. 12-1409 (D.C. Cir. Oct. 15, 2012); *California Communities Against Toxics v. EPA*, No. 12-1410 (D.C. Cir. Oct. 15, 2012); *Texas Oil & Gas Ass'n v. EPA*, No. 12-1411 (D.C. Cir. Oct. 15, 2012); *Western Energy Alliance v. EPA*, No. 12-1412 (D.C. Cir. Oct. 15, 2012); *Texas v. EPA*, No. 12-1417 (D.C. Cir. Oct. 15, 2012). These cases have been consolidated as *Independent Petroleum Ass'n of America v. EPA*, No. 12-1408 (D.C. Cir. Oct. 15, 2012).

²²⁸ *See, e.g.*, Request for Administrative Reconsideration by Interstate Natural Gas Association of America, Letter from Dan Rega, Regulatory Attorney, Interstate Natural Gas Association of America, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency, at 2-3 (Sept. 14, 2012).

²²⁹ IPAA Reconsideration Letter, *supra* note 92, at 2-3.

²³⁰ *Id.*

²³¹ *Id.* at 4-5.

²³² Western Energy Alliance Reconsideration Letter, *supra* note 86, at 3.

- The rules impose monitoring, recordkeeping, and other compliance requirements that are “simply impossible”,²³⁴ and
- EPA’s attempts at clarifying the new rules subsequent to publication in the *Federal Register* merit formal clarification through the notice and comment rulemaking requirement.²³⁵

On the other hand, several environmental groups have expressed concern that the new and revised rules do not go *far enough* in reducing emissions.²³⁶ EPA has recently indicated that it may grant some of the petitions, and has proposed to reconsider various aspects of the new and revised rules in 2013 and 2014.²³⁷ The manner in which these issues are addressed will not only impact ongoing compliance, but also the current legal challenges. It is too early in the briefing before the federal court to discern which issues will ultimately earn scrutiny. Nevertheless, the new and revised rules are largely effective *now*, and operators may be well served by reviewing whether they are currently in compliance, and by making plans to deal with the phase-in of future requirements.

IV. Conclusion

EPA does not operate oil and gas wells, gathering facilities, or gas plants. Nevertheless, EPA has promulgated hotly contested regulations that will absolutely impact the way industry approaches regulatory compliance for oil and gas development. These rules are complicated, and affect operations and equipment that have not been regulated before at the federal level. It’s unclear whether the current iteration of the rules will survive legal challenges, but EPA has demonstrated its intent to regulate every aspect of oil and gas development, potentially culminating in direct regulation of greenhouse gases through cap and trade or control requirements. Accordingly, now is the time for operators to confront the new regulatory environment impacting operations.

²³³ *Id.* at 7.

²³⁴ *See, e.g., id.* at 10-11; GPA Reconsideration Letter, *supra* note 113, at 9; Petition for Reconsideration by Texas Commission on Environmental Quality, Letter from Zak Covar, Executive Director, Texas Commission on Environmental Quality, to Lisa P. Jackson, Administrator, Environmental Protection Agency, at 4-8 (Oct. 12, 2012) (“Texas Letter”).

²³⁵ *E.g.*, Texas Letter, *supra* note 234, at 10-13;

²³⁶ *See generally* Petition for Reconsideration by Earthjustice *et al.*, Letter from Emma C. Cheuse, Earthjustice, *et al.*, to Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency (Oct. 15, 2012).

²³⁷ *See generally* Unopposed Motion of Respondent EPA to Sever the Challenges to the NSPS and NESHAP Rules, to Hold Litigation in Abeyance, and to Govern Further Proceedings, American Petroleum Institute v EPA, No. 12-1405 (D.C. Cir. Jan. 16, 2013).



EPA's New Oil & Gas Air Regulations A Summary of NSPS OOOO

Rocky Mountain Mineral Law Foundation
Special Institute on Air Quality Issues Affecting
Oil, Gas, and Mining Development

Denver, Colorado
February 28, 2013

Jay Christopher
Business Unit Manager
Air and Process Services

ENGINEERING SOLUTIONS. ADVANCING BUSINESS.

The more you explain it, the more I
don't understand it.

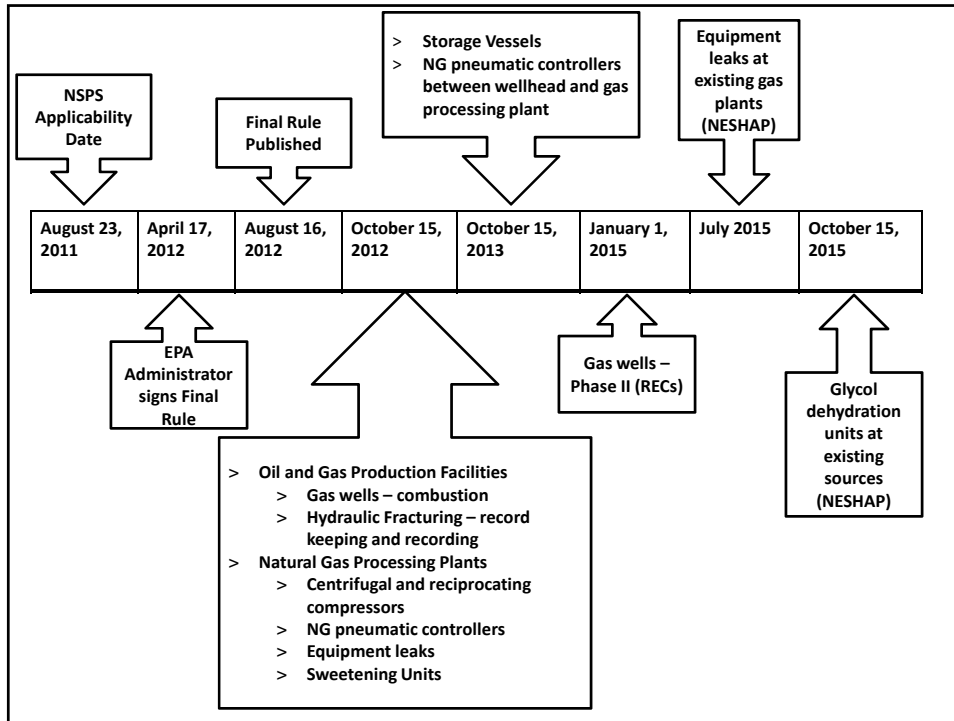
-Mark Twain

The focus of today's discussion

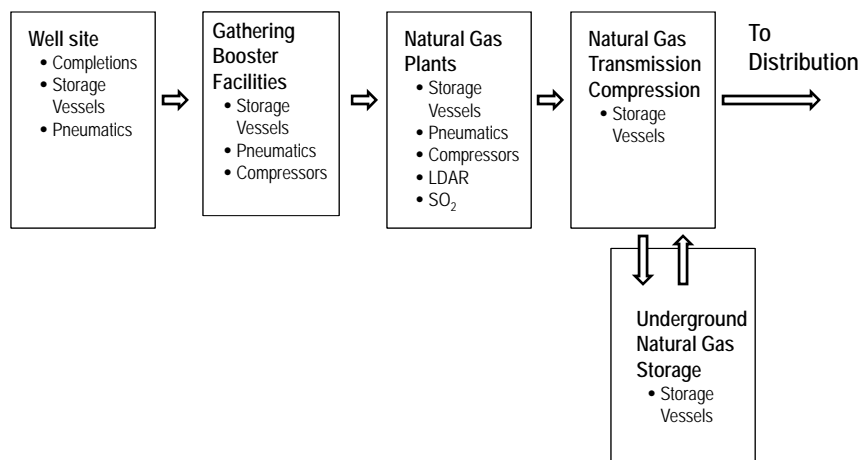
- US EPA published a new air regulation with broad impact to the oil and gas industry in the Federal Register on August 16, 2012
 - NSPS Subpart OOOO, Crude Oil and Natural Gas Production, Transmission and Distribution (a.k.a. "Quad O")
- I am not going to talk about the myriad of other air regulations that also affect this industry, but they include NSPS Kb, GG, KKK, LLL, IIII, JJJJ, KKKK, and NESHAP H, V, HH, VV, HHH, YYYY, and ZZZZ.

The legal route to NSPS Quad O

- January 14, 2009 - Lawsuit filed against EPA by WildEarth Guardians and San Juan Citizens Alliance
 - Failure to review and revise NSPS and NESHAP for oil and natural gas production source categories
- February 5, 2010 - Consent Decree entered
 - EPA agrees with environmental groups to review and revise regulations
- August 23, 2011 - Regulations proposed
 - NSPS applicability date
- April 17, 2012 - Regulations finalized
- August 16, 2012 - Regulations published



What is Covered Under NSPS 0000?



Green Completions: When Required

- During gas well completions (fracs and re-fracs) that commence after October 15, 2012
- Completion = flowback period between hydraulic fracturing and well shut-in or continuous flow to the flow line or storage vessel (whichever occurs first)
- Excludes
 - Wildcat, delineation, and low pressure wells
 - ♦ Use completion combustion device
 - ♦ REC not required
 - Exceptions may be applied for if not technically feasible or safe

Green Completions: What is Required

- Prior to January 1, 2015 – completion combustion device with continuous ignition, or a Reduced Emission Completion (REC) with combustion
 - General duty to maximize resource recovery and minimize releases
- January 1, 2015 and later – REC with combustion (for gases not suitable for entry to the flow line)
 - You must route all salable quality gas to the gas flow line
- Exemptions may be applied for if not feasible or safe

Gas Well Modification NSPS Triggers

- Fracturing or refracturing an existing well is an NSPS modification
 - Triggers Subpart OOOO for the gas well (but not other equipment)
- Gas wells that are refractured and use REC plus completion combustion controls are not considered modifications
 - But they must meet all post-2015 notification, recordkeeping, and reporting requirements

Reduced Emissions Completion (REC)

- *“Well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.”*



Completion Combustion Device

Definition:

- *“Any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.”*



Notification of Well Completions

- E-Mail notification to EPA
 - Owner/operator contact info
 - API well identification #
 - Geographic coordinates
 - Planned date to commence flowback
- At least 2 days prior to commencing completion operations
- Contents specified in rule
- Compliance with state advance notice rules satisfies the NSPS notification requirement

Gas Well Recordkeeping and Reporting

- Detailed recordkeeping requirements
 - Daily logs
- Annual reporting (2 options)
 - Standard Annual Report
 - Streamlined Annual Report
- Self-certification – a new wrinkle

Compressors

- Compressors located between wellhead and point of custody transfer
- “Commenced construction” is defined as the installation date
 - August 23, 2011 is the key date
 - Relocation is excluded



Compressors (con't)

- Centrifugal compressor with wet seals
 - 95% VOC reduction via control device
 - Performance testing, monitoring, recordkeeping, reporting, and notification requirements for the control devices
- Reciprocating compressors
 - Change rod packing at 26,000 hours or 36 months

Pneumatic Controllers at Gas Plants

- Affected Facilities:
 - Each single continuous bleed, natural gas-driven pneumatic controller
 - Commenced construction after August 23, 2011, compliance by October 15, 2012, or as installed
- Zero natural gas bleed rate required (e.g., air)
- Exemptions for safety and operational need
- Tag with installation date and identification information
- Annual reporting

Pneumatic Controllers in Production Sector



- Affected Facilities:
 - Each single continuous bleed natural gas-driven pneumatic controller with a bleed rate >6 scfh
 - Located between the wellhead and point of custody transfer
 - Commenced construction or modified after August 23, 2011
- Must be < 6 scfh bleed rate by early October 15, 2013
- Tag with installation date and identification information
- Exemptions for safety and operational need
- Recordkeeping and reporting

Storage Vessels

- Applies to each new, modified or reconstructed storage vessel in oil & natural gas production, natural gas processing, or natural gas transmission/storage facilities
 - Storage vessel on mobile equipment (e.g., frac tanks) that is intended to be located at a site for at least 180 days is an affected storage vessel
 - Excludes surge control vessels, knockout vessels, and pressure vessels designed to operate without emissions to atmosphere
 - If vessels already subject to NSPS Kb, or MACT G, CC, HH, WW, or HHH, then no additional controls are required

Storage Vessels (con't)

- If VOC emissions >6 tons/year, reduce emissions by 95% - compliance required by October 15, 2013. Controls may be fixed roof with control device or floating roof (meets NSPS Kb).
- 6 ton limit after federally enforceable controls
- Where no existing wells at the well site:
 - 30 days to determine if >6 tons/year VOCs
 - 60 days after startup for controls to be operational
- If existing wells at the well site, controls operational at startup.

Natural Gas Plants Equipment Leaks (LDAR)

- Applies to equipment in VOC or wet gas service
 - Presumption in rule that it is VOC or wet gas
- Does not apply to compressors
- Must meet specified sections of NSPS VVa
 - Valve leak rate to 500 ppm (was 10,000 ppm)
 - Annual connector monitoring
 - Pumps, pressure relief devices, open-ended valves/lines monitoring
 - Sampling connection systems are exempt
- October 15, 2012 effective date

Natural Gas Plants Equipment Leaks (LDAR)

- Gas Plant Processing Unit Definition
 - *Equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.*
- Check your process unit definitions!
- Check projects since August 2011!

NSPS OOOO Recordkeeping/Reporting

- Specific requirements for each type of equipment
- EPA granted relief from NSPS Subpart A notification provisions for:
 - Well completions
 - Compressors
 - Pneumatic controllers
 - Storage vessels
- Self-certification – senior company official

Methane Not Regulated

- NSPS Subpart OOOO regulates VOCs and SO₂
 - Not Methane or CO₂
- EPA considered co-benefit of methane reductions when assessing cost/benefit
- Northeastern states have filed suit for a methane standard

Startup, Shutdown, Malfunction

- No exemption for excess emissions caused by startup or shutdown. The standards apply at all times.
- Malfunction exceedances may be excused only if the source can prove the numerous listed elements of the affirmative defense.

Questions?

If you ask me anything I don't know, I'm not going to answer.

-Yogi Berra

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