Appendix A

Assessment of State-Level Fugitive Emissions Programs in Comparison to EPA NSPS Reconsideration Proposal

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This report addresses and responds to EPA's claims with regard to the relative efficacy of state-level fugitive emissions programs in its proposed rule, EPA's NSPS, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration, 83 Fed. Reg. 52056 (October 15, 2018) ("Proposal"), and supporting memo, Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa, EPA Docket ID No. EPA-HQ-OAR-2017-0483 (April 12, 2018). EPA claims that:

> "Through this evaluation, we have identified aspects of certain existing state fugitive emissions programs that we propose to find to be at least equivalent to the proposed amendments in this action."[i]

In the Proposal, EPA proposes to deem California, Colorado, Ohio, Pennsylvania, Texas, and Utah as states that have "equivalent" fugitive emissions programs for well sites.[ii] This Proposal also claims that California, Colorado, Ohio and Pennsylvania regulate compressor stations equivalently to the Proposal's standards.

EPA's suggestion that these states' LDAR programs are equivalent is devoid of any quantitative analysis and misrepresents the emissions reductions achievable by each state's program, as it ignores many differences between the fugitive emissions programs in these states, including scope and coverage of facilities and segments, threshold emissions detection requirements, time-frame for repairing leaks, and other provisions of each program. Many of these state programs' fugitive emissions requirements are significantly less rigorous than the proposed standards in EPA's Proposal, and thus achieve fewer benefits.

In this analysis, we quantitatively compare the wells and compressor stations covered and the emissions reduced from the so-called equivalent state programs to the proposed standards in the Proposal. We also include a detailed comparison of the scope and requirements of each state program. This comparison clearly indicates that many of these programs do not achieve the emissions reductions that the Proposal does within each state. These state programs therefore do not guarantee equivalency with the Proposal.

Furthermore, because the Proposal is a weakening of the original 2016 NSPS,[iii] we also compared state LDAR standards to the original NSPS requirements. When compared to the original 2016 NSPS requirements, the state programs achieved even fewer relative emissions reductions.

Analysis of Well Site Program Equivalency

Exhibit 1 below illustrates the relative coverage of state LDAR programs as percentages of the wells covered under the Proposal. (Not that Utah and Pennsylvania are not included in this graph and will be discussed separately). Combined, the state regulations in California, Colorado, Ohio, and Texas that EPA has identified as having "equivalent" fugitive emission programs cover only 34% of the total wells

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[i] 83 Fed. Reg. at 52,080.
[ii] *Id*.
[iii] 81 Fed. Reg. 35,824.

covered by the Proposal in these states. Moreover, even for the sources that are subject to some state programs, those programs vary in stringency and may not secure the same level of reductions as EPA standards (discussed subsequently). The methodology used to generate this and later graphs is in Appendix 1.

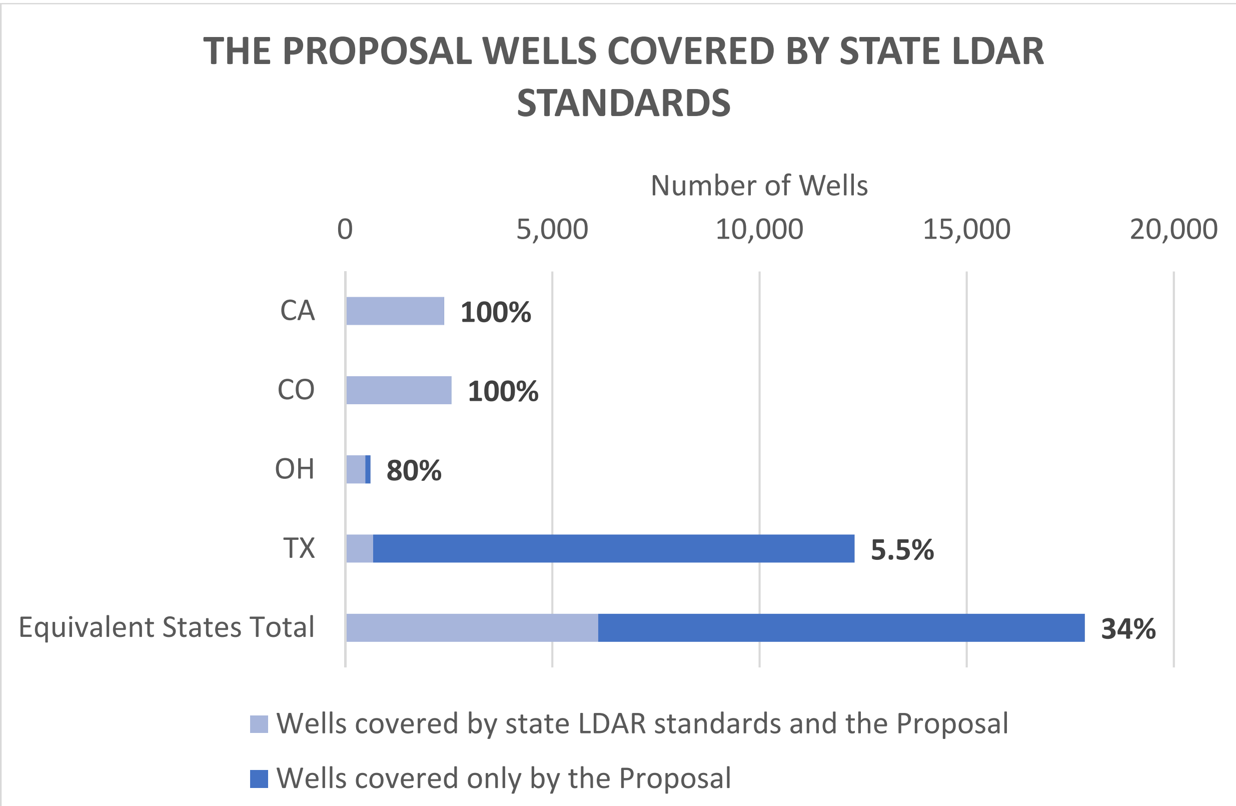

Exhibit 1. The Proposal wells covered by state LDAR standards

Clearly, for several states, existing state standards do not cover the full extent of what would be covered under the Proposal. For example, in Texas, the LDAR requirement only applies to wells with very high uncontrolled emissions (>10 or 25 tons per year (tpy)), an estimated 5.5% of the Proposal covered wells (as many as 11% and as few as 2.2%). Because Texas has a very large number of additional wells that would be covered by the Proposal, the emissions reductions lost if the state standards were allowed to substitute for the Proposal would be substantial.

The observed differences in number of wells covered under state regulation and under the Proposal requirements results in a significant decrease in the potential emission reductions within each state. Many of these state programs' fugitive emissions requirements are significantly less rigorous than the Proposal, and thus achieve fewer benefits. Exhibit 2 below illustrates the estimated emissions reductions from well sites within each state under consideration for equivalency. The following estimates are conservative, as they only take into account monitoring frequency and not differences in initial monitoring or repair requirements between the states and the Proposal.

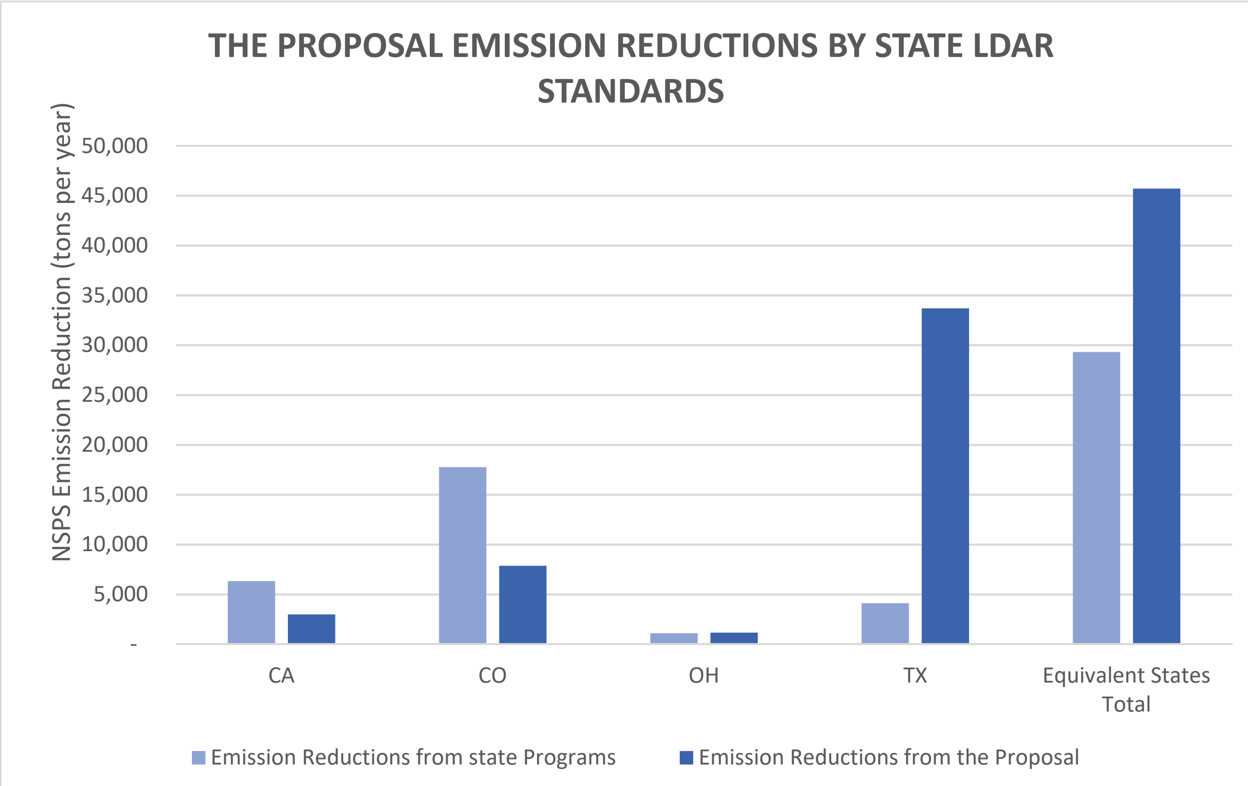

Exhibit 2: Emission reductions from state regulations compared to emission reductions from EPA Proposal

In California and Colorado, all wells covered by the Proposal are covered by state regulations, but with different monitoring frequency requirements. In California, quarterly monitoring meets the expected emissions reductions from the Proposal. However, the 90-day initial monitoring period is longer than allowed under the Proposal. In Colorado, well sites must use a monitoring frequency corresponding to VOC emissions from storage tanks. Using the methodology described in Appendix 1, the emissions reductions were deemed to meet the Proposal reductions.

Ohio state regulations denote that horizontally drilled, unconventional wells are covered. For these wells, Ohio requires quarterly monitoring for one year, then semiannual or annual (based on 2% leak rate). Data from the City of Fort Worth Natural Gas Air Quality Study (2011),[iv] shows that sites with less than 2% leaking components constitute 90% of total emissions and over 80% of sites. Because the quarterly monitoring impacts would likely not extend past the first year for these sites, this analysis assumes that 90% of Ohio emissions would undergo annual monitoring, and 10% would undergo semiannual monitoring. This brings the total emissions reductions in Ohio below what would be achieved under the Proposal.

[iv] Eastern Research Group, *The Natural Gas Air Quality Study (Final Report)* (July 13, 2011) http://fortworthtexas.gov/gaswells/air-quality-study/final/.

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In Texas, only 5.5% of wells are required to perform LDAR. Conservatively assuming that the highest emitting wells will perform LDAR (consistent with the Texas requirements), only 12% of the emissions that would be reduced under the Proposal would be reduced under Texas regulation. Furthermore, provisions of the Texas regulation allow for inspection frequency to decrease based on the percentage of leaking components. This reduction in inspection frequency would decrease the inspection frequency below what the Proposal requires and would therefore lead to less emission reductions than the Proposal would achieve. Furthermore, in Texas, the emission threshold for repair for certain combinations of distance from sensitive receptors and potential to emit is higher than the Proposal.

Utah requires semiannual monitoring for well sites where uncontrolled storage vessel and dehydrator emissions are greater than 4 tpy VOC. Due to a lack of data regarding site specific uncontrolled storage and dehydrator emissions, determining an accurate number of regulated well sites and subsequent emissions reductions was not feasible for Utah.

Pennsylvania's LDAR program covers unconventional well sites that are new and modified relative to August 8, 2018. This date is after the current NSPS effective start, so the majority of wells are excluded based on date. In the future, unconventional wells in Pennsylvania will be regulated at a higher monitoring frequency than required by the Proposal. However, none of the 1,600 wells covered under the current NSPS are currently regulated under Pennsylvania's GP5. Unless required to comply with the Proposal or Pennsylvanian regulations, these wells would continue to be unregulated, emitting approximately 2,900 tons per year of methane.

While California and Colorado meet the emission reduction levels accomplished by the Proposal, 65% of the 45,700 tons per year of methane that would be reduced by the Proposal in California, Colorado, Ohio, and Texas are lost due to a lack of coverage in Ohio and Texas. Under the Proposal, California and Colorado would account for a 10,800 tpy reduction in emissions, while Texas and Ohio would reduce a combined 34,800 tpy. Under state regulation, Texas and Ohio are only estimated to reduce 5,200 tpy. Even when accounting for larger reductions in emissions in California and Colorado due to higher monitoring frequency under state standards (an additional 13,200 tpy), there is still a net loss of 36% of the total emissions that would be reduced by the Proposal.

Because the Proposal is a weakening of the original 2016 NSPS, we also compared state LDAR standards to the original NSPS requirements. When compared to the original 2016 NSPS requirements and accounting for the larger emission reductions in California and Colorado, there is a net loss of 58% of the 69,600 tpy of emissions that would be reduced under the 2016 NSPS (Exhibit 3).

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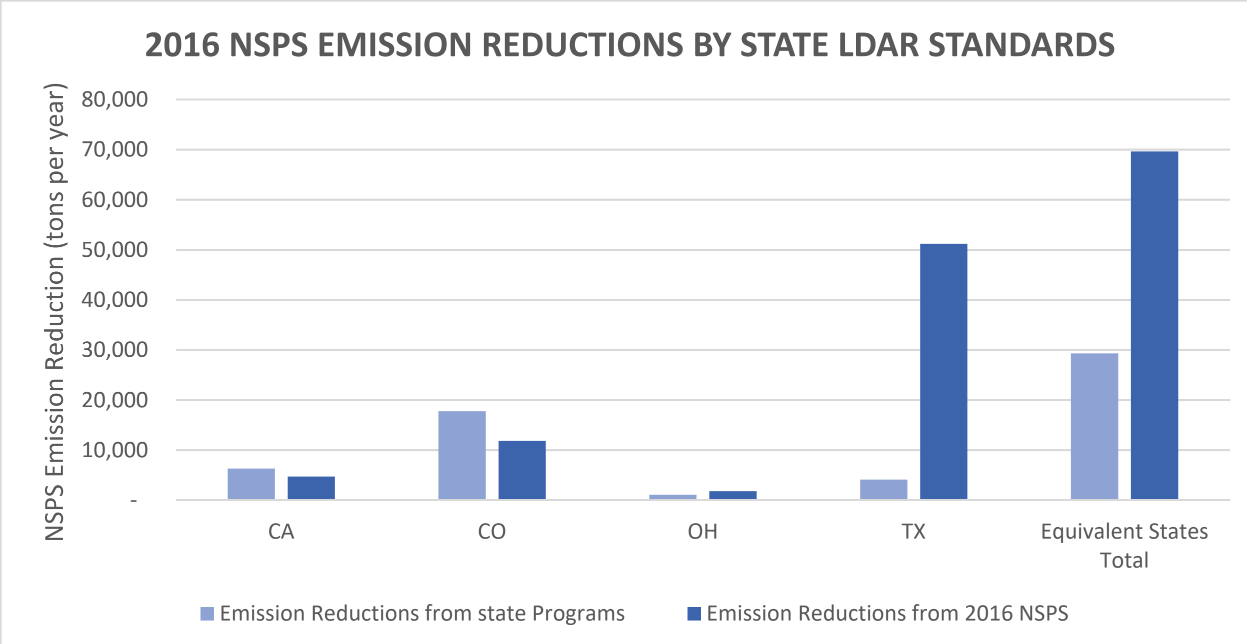

Exhibit 3: 2016 NSPS emissions reductions compared to equivalent state reductions

Analysis of Compressor Station Program Equivalency

California, Colorado, Ohio and Pennsylvania regulate compressor stations using monitoring frequencies higher than those included in the Proposal. In California, Ohio, and Pennsylvania, compressor stations must conduct LDAR quarterly. In Colorado, compressor stations falling under 7 §§XII.L conduct quarterly monitoring. Those that fall under 7 §§XVII.F use a tiered monitoring frequency dependent on actual VOC emissions: 0-12 tons/year, Annual; 13-50 tons/year, Quarterly; over 50 tons/year, Monthly. The proposed NSPS do not consider annual monitoring equivalent, therefore a minimum frequency of quarterly was used for all compressor stations in Colorado. While some operators may emit high enough levels of VOCs to perform monthly monitoring, data was unavailable to determine how many compressor stations would be required to do so. Therefore, quarterly LDAR was applied to all compressor stations regulated under state programs, a higher monitoring frequency than the semiannual monitoring being proposed in the NSPS Proposal. However, the effective start dates of these regulations in OH and PA result in reduced coverage in these states, and therefore lower emissions reductions.

In California and Colorado, all compressor stations covered by the Proposal are regulated. In Ohio, only new or modified compressor stations beginning on February 7, 2017 are regulated under Ohio GP 18.1. Pennsylvania regulation only covers new or modified compressor stations beginning on August 8, 2018.

While 100% of compressor stations in CO and CA are covered, only 56% of compressor stations in Ohio and 9% of compressor stations in Pennsylvania that would have been regulated under the Proposal would be currently required to perform LDAR. Of the 206 compressor stations that would be required to perform LDAR in CO, CA, OH, and PA, only 38% will be regulated because of the later effective dates in Ohio and Pennsylvania.

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Even accounting for more frequent monitoring in all four states, the lack of compressor station coverage in OH and PA result in a net reduction of only 2,300 TPY of methane, 51% of the 4,500 TPY of methane that would be reduced by the Proposal. If not required to comply with either their state standard or the NSPS, the 128 compressor stations not covered under Ohio and Pennsylvania regulations will release over 2,100 tons per year of methane.

State Program Requirement Analysis

This analysis solely takes into account monitoring frequency, however, there are additional factors within state regulations that could contribute to an increase in emissions if the state equivalency determinations are finalized. California, Ohio, and Texas require initial monitoring within 90 days, beyond the 60 day Proposal requirement. This additional time could allow undetected leaks to emit beyond what they would under the Proposal. While EPA will require sources using Method 21 to repair leaks above 500 ppm, in California right now, leaks below 10,000 ppm need not be repaired. New California regulations lower that threshold to 1,000 ppm (still higher than the NSPS threshold), but not until January 1, 2020. Additionally, Colorado's XVII.F final repair timeline is longer than NSPS Proposal requirements, indicating a leak could extend beyond the Proposal's 60 days. Colorado and Ohio also have delay of repair deadlines that EPA does not consider equivalent. All of these factors could contribute to increased emissions that would otherwise be reduced under the Proposal. These discrepancies between the state standards and the Proposal are summarized in Table 1.

To more granularly compare the Proposal and the state standards, the following tables compare program aspects including supply chain segment and facilities covered, coverage of new and existing facilities, percentage of wells covered by each state program that are covered by the Proposal, thresholds before leak detection is required, threshold emission levels before repair is required, and frequency of surveys required.

TABLE 1: OVERVIEW OF DIFFERENCES IN LDAR PROGRAMS BETWEEN THE PROPOSAL AND STATE PROGRAMS

Regulation	Monitoring Frequency	Initial Monitoring	Leak Threshold	Time for Final Repair
NSPS: 2018 Proposal	Non-low wells: Annual Low wells: Biennial	60 days	Visible leak for OGI, 500 ppm for Method 21	60 days
California	Quarterly	90 days	1000 ppm (effective 1/1/2020)	1,000-9,999 ppm: 14 days 10,000- 49,999 ppm: 5 days 50,000 ppm or greater: 2 days
Colorado 7XII.L Colorado 7 XVII.F	One-time-Monthly depending on VOC tpy	15-30 days 15-90 days	Visible leak for OGI, 500 ppm for Method 21 Visible leak for OGI, 500 ppm for Method 21	30 days N/A
Ohio	Quarterly for one year, then	90 days	Visible leak (OGI) or 500, 2,000, 10000 ppm (Method 21)	30 days

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	semiannual or annual			
Pennsylvania	Quarterly (unconventional wells only)	60 days	Visible leak for OGI, 500 ppm for Method 21, state-defined for other approved methods	15 days
Texas	Quarterly, then annual if % leaking valves is low	90 days	500, 2,000, or 10,000 ppm (dependent on PTE and distance from sensitive receptors)	15 days
Utah	Semiannual if uncontrolled VOC > 4 tpy	60 days	Visible leak for OGI or 500 ppm for Method 21	15 days

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TABLE 2. SUPPLY CHAIN SEGMENT

EPA NSPS: WELL SITES, COMPRESSOR STATIONS, NATURAL GAS PROCESSING PLANTS[1]	
CA[2]	(1) ONSHORE & OFFSHORE CRUDE OIL OR NG PRODUCTION (2) CRUDE OIL, CONDENSATE, AND PRODUCED WATER SEPARATION AND STORAGE (3) NG UNDERGROUND STORAGE (4) NG GATHERING AND BOOSTING STATIONS (5) NG PROCESSING PLANTS (6) NG TRANSMISSION COMPRESSOR STATIONS
CO[3]	OIL AND GAS EXPLORATION AND PRODUCTION OPERATIONS, WELL PRODUCTION FACILITIES, NATURAL GAS COMPRESSOR STATIONS, AND NATURAL GAS PROCESSING PLANTS
OH[4]	UNCONVENTIONAL, HORIZONTAL, NON-TITLE V WELL SITES; GATHERING AND BOOSTING COMPRESSOR STATIONS
PA[5]	NATURAL GAS GATHERING AND BOOSTING STATIONS; UNCONVENTIONAL WELL SITES WHOSE OVERALL VOC EMISSIONS REMAIN BELOW 2.7 TPY; ADDITIONAL MEASURES **PROPOSED** FOR UNCONVENTIONAL WELL SITES, REMOTE PIGGING STATIONS, NG COMPRESSION STATIONS, PROCESSING PLANTS, AND TRANSMISSION STATIONS
TX[6]	(1) PETROLEUM REFINERIES; NATURAL GAS PROCESSING PLANTS IN OZONE NON-ATTAINMENT AREAS; (2) OIL AND GAS PRODUCTION AND PROCESSING SITES WITH THE POTENTIAL TO EMIT AT LEAST 10 OR 25 TPY OF UNCONTROLLED VOCS (DEPENDING ON DISTANCE FROM SENSITIVE RECEPTOR)
UT[7]	WELL SITES; TANK BATTERIES

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TABLE 3. SCOPE

EPA NSPS: NEW AND MODIFIED SOURCES (RELATIVE TO SEPTEMBER 18, 2015)	
CA[2]	NEW AND EXISTING
CO[3]	NEW AND EXISTING
OH[4]	NEW AND MODIFIED (RELATIVE TO APRIL 4, 2014)
PA[5]	NEW AND MODIFIED (RELATIVE TO AUGUST 8, 2018)
TX[6]	NEW AND EXISTING
UT[7]	NEW AND EXISTING

TABLE 4. PERCENT COVERAGE BY STATE RULE OF WELL SITES THAT ARE COVERED BY THE PROPOSAL RULE

WELLS COVERED BY NSPS: 33,244 WELLS	
CA[2]	100%
CO[3]	100%
OH[4]	80%
PA[5]	0%
TX[6]	5.5%
UT[7]	100%

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TABLE 5. THRESHOLD FOR INSPECTION

EPA NSPS: NONE	
CA[2]	NONE
CO[3]	NONE
OH[4]	NONE
PA[5]	NONE
TX[6]	PRODUCTION FACILITY: VOC EMISSIONS GREATER THAN 10 TPY OR 25 TPY, DEPENDING ON DISTANCE FROM SENSITIVE RECEPTOR
UT[7]	UNCONTROLLED STORAGE TANK AND DEHYDRATOR EMISSION > 4 TPY

TABLE 6. THRESHOLD FOR REPAIR

EPA NSPS: 500 PPM REPAIR THRESHOLD IF USING METHOD 21.	
CA[2]	1,000 PPM TOTAL HYDROCARBON LEAK THRESHOLD WHEN FULLY IMPLEMENTED.
CO[3]	500 PPM LEAK THRESHOLD (NEW) AND 2,000 PPM (EXISTING COMPRESSOR STATIONS), IF USE METHOD 21.
OH[4]	500 OR 10,000 PPM LEAK THRESHOLD FOR METHOD 21
PA[5]	500 PPM FOR METHOD 21
TX[6]	THRESHOLD FOR PRODUCTION FACILITY DEPENDS ON COMPONENT, DISTANCE FROM SENSITIVE RECEPTOR AND EMISSION THRESHOLD: 500 PPMV VOC, 2,000 PPMV OR 10,000 PPMV
UT[7]	500 PPM OR GREATER WITH AN ANALYZER OR A TUNED DIODE LASER ABSORPTION SPECTROSCOPY (TDLAS) ANALYZER.

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TABLE 7. FREQUENCY

EPA NSPS: INITIAL SURVEY WITHIN 60 DAYS OF STARTUP OR MODIFICATION ANNUAL FOR NON-LOW PRODUCTION WELL SITES; BIANNUAL FOR LOW PRODUCTION WELL SITES; SEMIANNUAL INSPECTIONS FOR COMPRESSOR STATIONS	
CA[2]	QUARTERLY, INITIAL INSPECTION WITHIN 90 DAYS
CO[3]	INSPECTION FREQUENCY DEPENDS ON ACTUAL FUGITIVE VOC TON PER YEAR EMISSIONS FOR COMPRESSOR STATIONS: COMPRESSOR STATIONS: 0-12: ANNUAL 13-50: QUARTERLY OVER 50: MONTHLY INSPECTION FREQUENCY DEPENDS ON ACTUAL UNCONTROLLED VOC EMISSIONS FROM STORAGE TANKS OR FACILITY, IF NO TANKS, AT WELL SITES WELL SITES: 0-6: ONE-TIME 7-12: ANNUAL 13-50: QUARTERLY 50 AND ABOVE: MONTHLY MULTI-WELL SITES >20 WITHOUT TANKS: MONTHLY
OH[4]	INITIAL INSPECTION WITHIN 90 DAYS OF STARTUP; QUARTERLY INSPECTIONS FOR NEXT 4 QUARTERS; STEP DOWN TO SEMI-ANNUAL AFTER 4 CONSECUTIVE QUARTERS WITH NO MORE THAN 2% OF COMPONENTS LEAKING; STEP DOWN TO ANNUAL AFTER 2 CONSECUTIVE SEMI-ANNUAL INSPECTIONS IF NO MORE THAN 2% OF COMPONENTS LEAKING; STEP UP TO ORIGINAL QUARTERLY INSPECTIONS WHENEVER 2% OF MORE OF COMPONENTS ARE LEAKING
PA[5]	INITIAL INSPECTION WITHIN 60 DAYS OF STARTUP; QUARTERLY INSPECTION FOR UNCONVENTIONAL WELL SITES; QUARTERLY INSPECTIONS FOR G&B STATIONS
TX[6]	QUARTERLY WITH POSSIBILITY TO REDUCE TO SEMI-ANNUAL OR ANNUAL IF CERTAIN CONDITIONS ARE MET

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UT[7]	INITIAL INSPECTION WITHIN 60 DAYS. SEMIANNUAL INSPECTIONS FOR WELL SITES WITH UNCONTROLLED STORAGE TANK AND DEHYDRATOR EMISSIONS > 4 TPY

References

1. EPA, Oil and Natural Gas Sector: Emission Standards for New and Modified Sources Reconsideration, available at https://www.epa.gov/sites/production/files/2018-09/documents/frnoilgasreconsideration2060-at54nprm20180910.pdf
2. California Code of Regulations title 17, 95665-95677 (7-17-2017), available at https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I401BB8146DA14B519A991D7827913AEE&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)
3. Colorado Air Quality Control Commission, Colorado Regulation 7, §§XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations. Available at: https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2341&deptID=16&agencyID=7&deptName=Department%20of%20Public%20Health%20and%20Environment&agencyName=Air%20Quality%20Control%20Commission&seriesNum=5%20CCR%201001-9
4. Ohio EPA General Permit 12.1 and 12.2, available at http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx; Ohio General Permit 18.1,, available at http://epa.ohio.gov/dapc/genpermit/ngcs.aspx
5. PA DEP GP 5 and 5A available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx
6. Texas Administrative Code Title 30, Part 1, Chapter 115, Subchapter D, Division 2 and 3; available at http://texreg.sos.state.tx.us/public/readtac%24ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=115&sch=D&div=3&rl=Y and http://texreg.sos.state.tx.us/public/readtac%24ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=115&sch=D&div=2&rl=Y
7. Utah Administrative Code R307-509, available at https://www.utah.gov/pmn/files/359797.pdf#page=2

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Appendix 1

Methodology for calculating the percent coverage by state rule of well sites covered by the Proposal

The original wells that would be covered by the Proposal were identified using data from DrillingInfo, a proprietary database that compiles a wide range of drilling- and production-related information from state oil and gas commissions. New and modified active wells relative to September 18, 2015 are covered by the Proposal. New wells were identified as those with a spud date on or after September 18, 2015 and those with a missing spud date but with a first production date on or after September 18, 2015 (first production is reported by month so the formula conservatively uses October 1, 2015). Modified wells were selected as those with a completion date on or after September 18, 2015. A consistent end date of November 20, 2018 was used to maintain a subset of wells throughout analysis.

Wells were also filtered by Production Type and Status. Production Type was limited to CBM, GAS, OIL, O&G, OIL (CYCLIC STEAM), WATERFLOOD, STEAMFLOOD, production Status was limited to “Active”. The following fields were included in the download: API/UWI, Operator Alias, County/Parish, Production Type, Producing Status, Drill Type, First Production Date, Last Production Date, Cumulative Gas, Cumulative Oil, Latest Oil, Latest Gas, Last Test Date, Completion Date, Well Count, Months Produced, Spud Date, State, Surface Latitude, Surface Longitude, Basin, Country, Reservoir, Prac IP BOE, Cumulative GOR.

Out of the set of 33,244 wells, the respective state regulations and permitting programs were applied to determine how many wells would be covered by an equivalent state’s LDAR program.

California and Colorado LDAR standards cover new and existing wells without any throughput or emission thresholds, so 100% of the Proposal wells in California and Colorado would be covered under state standards.

The Ohio permit requiring LDAR covers unconventional, horizontal, non-Title V well sites that are new and modified relative to April 4, 2014. This date is prior to the Proposal cut-off date, so no wells are excluded based on date. DrillingInfo does indicate whether a well is horizontal but does not indicate whether it is unconventional (for Ohio). Therefore, to be conservative, all horizontal wells in Ohio were assumed to be unconventional and therefore to qualify for the state permit requiring LDAR. Horizontal wells were filtered by selecting wells with Drill Type “H”. The resulting 80% of Proposal wells covered under state standards is therefore an upper bound, as some horizontal wells may be conventional and would therefore not qualify for this permit (and thus for LDAR requirements).

Pennsylvania’s LDAR program covers unconventional well sites that are new and modified relative to August 8, 2018. DrillingInfo data was used to determine whether the well was “unconventional” and categorize wells as new or modified as of August 8, 2018. The Proposal wells in Pennsylvania were filtered using the “Reservoir” field as a criterion (ex: “MARCELLUS SHALE (UNCONVENTIONAL)”).

Of the unconventional wells constructed or modified on or after August 8, 2018, none are currently active and therefore 0% of the wells that would have been regulated under the Proposal would be regulated under Pennsylvania requirements.

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Texas LDAR requirements only apply to wells required to apply for the Standard Permit, which is based on uncontrolled VOC emissions (>10 or 25 tpy) and distance from a sensitive receptor, such as a home or school. Applications for Standard Permits were pulled from the TCEQ Records Online database (https://www.tceq.texas.gov/agency/data/records-services/welcome-to-tceq-records-online). Standard Permits for compressor stations and processing plants were removed. The remaining well site Standard Permits were analyzed to filter ones required to conduct LDAR. This process yielded 3,138 well sites in Texas required to conduct LDAR under the Texas Standard Permit. Assuming an average of 2 wells per well site, as the Proposal does, yields 6,276 wells in Texas required to conduct LDAR under state rules. The Standard Permits do not supply enough information to determine which of these wells are also subject to the 2016 NSPS OOOOa rule. Therefore, an upper and lower bound were determined for the percentage of Proposal wells in Texas covered by state LDAR rules. For the lower bound, the 6,276 LDAR wells in Texas were divided by the total number of active wells to yield 2.2%. For the upper bound, the 6,276 LDAR wells in Texas were divided by the number of new and modified wells relative to April 1, 2011 to yield 11%. (This date is the relevant date for the Standard Permit for facilities located in the Barnett Shale. The Standard Permit for facilities not located in the Barnett Shale does not have a relevant date. Using the 4/1/11 date assumes that only wells new and modified relative to the date are required to conduct LDAR, making this estimate an upper bound).

Methodology for calculating the emissions reduced by state rule of well sites covered by the Proposal

Wells covered by the Proposal and various state standards were identified using the methodology described above. These wells were then classified as low producing ($<$ 15 barrels of oil equivalent per day, boed) or non-low producing ($\geq$ 15 boed). They were further defined as (i) gas well site (gas-to-oil (GOR) ratio of $>$ 100 Mcf/barrel), (ii) oil well site with associated gas production (0.3 Mcf/barrel $<$ GOR $<$ 100 Mcf/barrel), and (iii) oil well site (GOR $<$ 0.3 Mcf/barrel). Emissions factors[5] for each well site type were converted from tpy/site to tpy/well using a wells-per-site ratio based on 2014 data. These emissions factors were then applied to the number of wells under each production type and level to calculate CH4 (tpy) for each well. Using EPA's fugitive percent reduction numbers for each monitoring frequency, the emission reductions for each state were calculated. To calculate the emissions reduced by the Proposal, an annual frequency reduction of 40% was applied to all non-low production wells and a biennial frequency reduction of 30% was applied to all low production wells. For California, a semiannual frequency percent reduction of 60% was applied to all wells. In Ohio, a quarterly frequency percent reduction of 80% was applied to all horizontal wells. In Colorado and Utah, each well was bucketed by threshold. VOC tpy was converted to methane tpy using a 1:3.6 ratio. Then methane tpy were converted to Mcf/yr, and finally to BOE/yr and BOE/day. Using production values for each well, we were able to apply the correct monitoring frequencies to each well. In Colorado, > 0 and < 6 tpy VOC, One-time (0% reduction); > 6 and < 12 tpy VOC, Annually (40% reduction); > 12 and < 50 tpy VOC, Quarterly (80% reduction); > 50 tpy VOC, Monthly (90% reduction). In Utah, all well sites with uncontrolled storage tank and dehydrators emissions > 4 tpy VOC use semiannual monitoring with a percent reduction of 60%. Only 5.5% of the Proposal wells in Texas are covered by the Standard Permit

[5] Omara, Mark. *A technical analysis of the forgone methane emissions reductions as a result of EPA's proposed reconsideration of the 2016 NSPS standards for oil and gas production sites* (included as an appendix with Environmental Defense Fund's comments in this rulemaking docket).

(roughly 676 wells). Because the Standard Permit only covers high-emitting wells, the top 676 wells in terms of emissions were assumed to be covered under the Standard Permit. An 80% reduction was then applied to the emissions of these 676 wells to account for quarterly monitoring (this analysis ignores the potential step-down of monitoring frequency allowed under the Standard Permit).

Methodology for calculating the percent coverage by state rule of compressor covered by the Proposal

Using identical methods to the 2018 GHGI methodology, the number of Gathering & Boosting, Storage, and Transmission compressor stations were calculated for each state in 2015. This provided the proportional numbers of compressor stations in each state. The Proposal provides year-to-year increases in each compressor station type, 212 G&B stations, 36 Transmission stations, and 2 storage station per year. These rates were used to determine the number of new compressor stations covered under the Proposal from September 18, 2015, to present day. The percentage of compressor stations in each state was then applied to find the number of new compressor stations covered by the Proposal in each state. This method was then duplicated to determine the number of new compressor stations covered under state regulation in OH and PA, using each respective effective date as the start of the coverage period.

Methodology for calculating the emissions reduced by state rule of compressor stations covered by the Proposal

Using the Proposal emissions factors for G&B, Transmission, and Storage, of 35.14 TPY, 40.4 TPY, and 142.4 TPY respectively, we were able to estimate emissions for each compressor type for each state. The percent reduction in emissions under the Proposal was calculated by applying a percent reduction of 60% for semiannual monitoring to the total emissions for each state. To compare to the state standards, a quarterly monitoring frequency percent reduction of 80% was applied to CA, CO, OH, and PA compressor station emissions. (While CO could require up to monthly inspections depending on TPY of VOC, this data was not available to determine which compressor stations would require each inspection frequency, and therefore a standard rate of quarterly inspection was used.)

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