

State of Colorado

2011 AND 2017 OIL AND GAS EMISSIONS INVENTORY DEVELOPMENT

Supporting the

Denver Metro/North Front Range
State Implementation Plan
for the 2008 8-Hour Ozone
National Ambient Air Quality Standard

Approved: November 17, 2016



COLORADO
Department of Public
Health & Environment



2011 AND 2017 OIL AND GAS EMISSIONS INVENTORY DEVELOPMENT

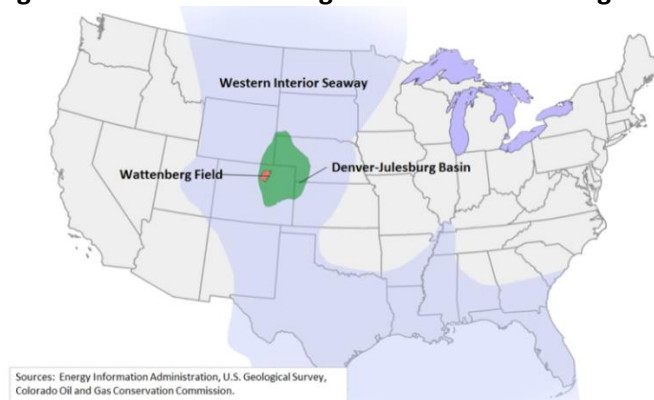
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1.1 INTRODUCTION

The 2011 and 2017 Oil and Gas Emissions Inventory is presented and discussed in in the Moderate Area State Implementation Plan (SIP) for the 2008 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) in chapters 3 and 4 respectively. This Technical Support Document (TSD) supports these emissions inventories as well as the Reasonable Further Progress (RFP) demonstration in chapter 4 and the Attainment Demonstration in chapter 5.

Emissions from the oil and gas sector are a significant contributor in both the 2011 (base year) and 2017 (future year) emissions inventories for the Denver Metro/North Front Range (DM/NFR) area. The oil and gas industry has changed drastically since 2011 due to new regulations and advancements in technology, which has resulted in a significant change in emissions between the base and future year. While the base year inventory was based on a simple methodology using a single emission factor (EF) multiplied by production, which had been the standard practice for years, the future year inventory had to be reexamined in order to take into account the new ways of extracting and processing oil and gas and the new controls that have been incorporated into the process at the well pad in the Denver-Julesburg (DJ) basin. A map of the DJ Basin is provided in Figure 1.

Figure 1 – Denver-Julesburg Basin and Wattenberg Oil Field



The oil and gas emissions inventory is broken out into three segments: point sources; area sources; and condensate tanks. Condensate tanks are technically area sources, but due to the magnitude of volatile organic compounds (VOC) emissions from this source category and the sophisticated methodology developed to estimate future year emissions, they were addressed separately in the inventory development process. Table 1 is a summary of the 2011 and 2017 oil and gas emissions inventory for VOCs, nitrogen oxides (NO_x), and carbon monoxide (CO) for the DM/NFR nonattainment area.

Table 1 – 2011 and 2017 Oil and Gas Emissions Inventory for DM/NFR Ozone Nonattainment Area

Subcategories	VOC (tpd)			NO _x (tpd)			CO (tpd)		
	2011	2017	Δ	2011	2017	Δ	2011	2017	Δ
Oil and Gas Point Sources	14.8	16.3	1.5	18.1	20.6	2.6	17.0	19.7	2.7
Condensate Tanks	216.0	78.7	-137.3	1.1	0.6	-0.5	2.3	2.3	-0.1
Oil and Gas Area Sources	48.9	59.0	10.0	22.2	44.6	22.3	12.9	31.4	18.5
TOTAL Oil and Gas Inventory	279.7	154.0	-125.8	41.4	65.8	24.4	32.2	53.4	21.1

1.2 OIL AND GAS POINT SOURCES

The oil and gas point source emissions inventory was the most straightforward to develop and is provided in Table 2. This inventory is based upon the Air Pollutant Emission Notice (APEN) database, which is administered by the Colorado Department of Public Health and Environment (CDPHE) Air Pollution Control Division (APCD). Companies are required to report to the APEN database on a regular basis, with reporting frequencies dictated by annual emissions thresholds.

Table 2 – 2011 and 2017 Oil and Gas Point Source Inventory

Description	VOC (tpd)			NO _x (tpd)			CO (tpd)		
	2011	2017	Δ	2011	2017	Δ	2011	2017	Δ
Oil and Gas Point Sources									
External Combustion Boilers	0.0	0.1	0.1	0.1	0.3	0.2	0.1	0.3	0.3
Industrial Processes	2.7	7.5	4.8	0.2	1.1	0.9	0.3	1.8	1.4
Internal Combustion Engines	5.0	7.8	2.8	17.7	19.2	1.5	16.6	17.5	0.9
Petroleum/Solvent Evaporation	7.1	1.0	-6.1	--	--	--	--	--	--
Subtotal	14.8	16.3	1.5	18.1	20.6	2.6	17.0	19.7	2.7

1.2.1 2011 and 2017 Oil and Gas Point Source Inventory Development Process

Except for condensate tanks describe below, both the 2011 and 2017 point source emissions inventories were developed in the same manner. Actual 2011 reported APEN data was used for the 2011 emissions inventory and actual 2014 reported APEN data was grown by the projected increase in oil production from 2014 to 2017 to estimate the 2017 emissions inventory. The inventories are broken out into four subcategories: external combustion boilers; industrial processes; internal combustion engines; and petroleum and solvent evaporation. For internal combustion engines federal non-road engine standards were factored into the future year projections. The four subcategories incorporated emissions from the following processes are listed in Table 3.

Table 3 – Oil and Gas Point Source Emissions Processes Reported to APEN Database**External Combustion Boilers**

- Commercial/Institutional - Natural Gas
- Industrial - Natural Gas

Industrial Processes

- Miscellaneous Manufacturing Industries - Miscellaneous Industrial Processes
- Oil and Gas Production - Crude Oil Production
- Oil and Gas Production - Fugitive Emissions
- Oil and Gas Production - Natural Gas Processing Facilities
- Oil and Gas Production - Natural Gas Production
- Oil and Gas Production - Process Heaters
- Petroleum Industry - Blowdown Systems
- Petroleum Industry – Flares

Internal Combustion Engines

- Commercial/Institutional - Distillate Oil (Diesel)
- Electric Generation - Distillate Oil (Diesel)
- Electric Generation - Natural Gas
- Industrial - Distillate Oil (Diesel)
- Industrial - Large Bore Engine

- Industrial - Natural Gas

Petroleum and Solvent Evaporation

- Organic Chemical Storage - Fixed Roof Tanks - Alcohols
- Organic Chemical Storage - Pressure Tanks - Alkanes (Paraffins)
- Organic Chemical Transportation - Specific Liquid
- Petroleum Liquids Storage (non-Refinery) - Bulk Plants
- Petroleum Liquids Storage (non-Refinery) - Bulk Terminals
- Petroleum Liquids Storage (non-Refinery) - Oil and Gas Field Storage and Working Tanks
- Petroleum Product Storage at Refineries - Fixed Roof Tanks (Varying Sizes)
- Surface Coating Operations - Miscellaneous Metal Parts
- Transportation and Marketing of Petroleum Products - Gasoline Retail Operations - Stage I
- Transportation and Marketing of Petroleum Products - Tank Cars and Trucks

1.3 CONDENSATE TANKS

As mentioned previously, oil and gas condensate tanks fall under the area source category and are provided in Table 4. Due to being the largest source of VOC emissions, this inventory was developed separately from the rest of the area source estimates and was the most labor intensive.

Table 4 – 2011 and 2017 Condensate Tank Inventory

Description	VOC (tpd)			NO _x (tpd)			CO (tpd)		
	2011	2017	Δ	2011	2017	Δ	2011	2017	Δ
Condensate Tank - Subtotal	216.0	78.7	-137.3	1.1	0.6	-0.5	2.3	2.3	-0.1

1.3.1 2011 Condensate Tank Inventory Development Process

The 2011 condensate tank inventory for VOC emissions was initially developed in 2014 as one of the requirements for a Marginal ozone nonattainment area. The emissions inventory was based on production data from the Colorado Oil and Gas Conservation Commission (COGCC) using a VOC EF of 13.7 pounds per barrel (lbs/bbl), which was the approved EF for condensate tanks in the nonattainment area. This EF was derived by the APCD in 2002 based on a study by Lesair Environmental¹ on flashed gas from condensate oil samples. Through 2011, all wells were assumed to be vertical orientation with only one stage of separation; therefore the 13.7 lbs/bbl VOC EF was considered to be fairly representative for that time period.

For the nonattainment area, Regulation No. 7, Section XII.D requires all subject storage tanks (i.e. tanks emitting over two tons of VOCs per year) to achieve a 90% overall system-wide level of control, referred

¹ E&P Storage Tank VOC Emission Study.” Prepared for Colorado Oil & Gas Association. Prepared by Lesair Environmental, Inc.

to as system-wide control (SWC). Field observations in the 2009–2010 time frame using infrared (IR) cameras and other methodologies indicated that in practice emissions from controlled storage tanks sometimes escaped through thief hatches and pressure relief valves and therefore were not being fully captured and combusted in the flare. Based on this evidence, the 2011 oil and gas inventory assumed that only 75% of the emissions from storage tanks were being captured and combusted in the flare, which is referred to as capture efficiency (CE).

Rule effectiveness (RE) is used by EPA to adjust emissions estimates to account for underestimates due to compliance failures. RE was assumed to be 80% due to the amount of venting observed by CDPHE APCD field investigators using an IR camera and is consistent with the RE assumed in the 2008 Ozone SIP for the 1997 ozone NAAQS². Rule Penetration (RP) is the percentage of uncontrolled emissions that are required to be controlled by the federally enforceable regulation. RP was based on production data from Weld County, from which it was determined that 97.7% of uncontrolled emissions were from tanks greater than two tons per year, thus RP was assumed to be 97.7% resulting in a total control rate of 52.6%. All four of these control factors are included in the emissions calculation, which is shown in Equation 1 below.

Equation 1

$$Emissions (tpd) = 2011 Production \left(\frac{bbls}{yr} \right) \times EF \left(\frac{13.7 \left(\frac{lbs}{bbl} \right)}{2000 \left(\frac{lbs}{ton} \right)} \right) \times \frac{1 yr}{365 days} \times (1 - (SWC \times CE \times RE \times RP))$$

$$Emissions (tpd) = 2011 Production \left(\frac{bbls}{yr} \right) \times EF \left(\frac{13.7 \left(\frac{lbs}{bbl} \right)}{2000 \left(\frac{lbs}{ton} \right)} \right) \times \frac{1 yr}{365 days} \times (1 - (90\% \times 75\% \times 80\% \times 97.7\%))$$

Data from the Colorado APEN database was used to estimate the NO_x and CO emissions for this source category. There are no NO_x or CO emissions directly from condensate tanks. Rather, these emissions are associated with the flare used to combust emissions from the tank. The 2011 condensate tank emissions inventory is provided in Table 5.

Table 5 - 2011 Oil and Gas Condensate Tank Emissions

Description	2011 (tpd)		
	VOC	NO _x	CO
Condensate Tanks	216.0	1.1	2.3

1.3.2 2017 Condensate Tank Inventory Development Process

Starting around 2012, the number of vertical wells being drilled in the DJ basin began to decline with nearly all new wells drilled being horizontal. Horizontal wells are able to reach a much wider area in the formation and are thus able to extract more energy with a fewer number of wells, making it a more efficient technology for today's oil and gas sector. In addition, multiple stages of separation and tankless production facilities allow for more gas capture, which reduces flash emissions and enables more product to be sent to the sales line.

² Denver Metro Area & North Front Range Ozone Action Plan, Approved by AQCC Dec. 12, 2008, www.colorado.gov/pacific/sites/default/files/AP_PO_Denver-Ozone-Action-Plan-2008.pdf

Due to the fast pace of the oil and gas industry and these technological advancements that have occurred over the past six years as a result of regulation and innovation, the established vertical well derived 13.7 lbs/bbl EF was determined to no longer be representative of current industry practice involving horizontal wells. This necessitated the need for newer methodologies that took into account the current landscape of the oil and gas industry. Therefore, the APCD and the Regional Air Quality Council (RAQC) worked in tandem to engage and consult with industry to determine what recent controls and technologies were being used in the DM/NFR nonattainment area and how this was expected to impact emissions in the future.

In May 2015, the APCD and RAQC met with several petroleum industry representatives to discuss the anticipated process for the development of the 2017 oil and gas emissions inventory. This included staff from Anadarko Petroleum Corporation, Bonanza Creek Energy Inc., Encana Corporation, Noble Energy Inc., PDC Energy Inc., and Whiting Petroleum Corporation, which represented about 85% of the oil production in the in the DJ basin. The APCD and RAQC also included the Colorado Oil & Gas Association (COGA) in these discussions as representation for the remaining, smaller producers in the nonattainment area.

Type of Data Provided

Based upon these discussions, these producers agreed to provide site specific information related to drilling, fracing, production, etc. for both 2014 and 2017 to aid in the development of a much more detailed inventory than had ever historically been crafted. This allowed for the consideration of advancements in process and technology in the inventory. From the top six producers, 2014 actual data was provided, which helped in developing EFs based on well orientation (i.e. horizontal and vertical) and stage of separation (i.e. tankless, 1 stage, 2 stage, and 3 stage). Five of the six companies also provided 2017 data, which aided in future production estimations. The type of information provided by the producers is listed in Table 6 and a detailed listing of the data fields requested is available in Appendix A.

Table 6 – Data Inquiry from Top Six Oil and Gas Producers in DJ Basin

General Information	Engines
○ Facility ID/Permitted Name/AIRS ID ○ Facility Oil Production ○ Facility H2O Production ○ Well Orientation	○ Type and runtime ○ Uncontrolled emission factors ○ Controlled tons per year
Separator Information	Burner
○ Number of Separators ○ Stages of Separation ○ Uncontrolled emission factors ○ Controlled tons per year	○ Flare rating ○ Uncontrolled emission factors ○ Controlled tons per year
Oil Tanks	Well Unloading
○ Oil Tank Uncontrolled Production (bbls) ○ Primary and Secondary Control Production (bbls) ○ Uncontrolled emission factors ○ Controlled tons per year	○ Emissions rate ○ Annual emissions
Drilling	H2O Tanks
○ Fuel type, use (gal), and heat content ○ Uncontrolled emission factors ○ Controlled tons per year	○ H2O Uncontrolled Production (bbls) ○ Uncontrolled emission factors ○ Controlled tons per year
Completions/Recompletions	Loadouts
○ Fracing and Completion Vent: Fuel type, use (gal), and heat content ○ Uncontrolled emission factors ○ Controlled tons per year	○ Volume (bbls) ○ Uncontrolled emission factors ○ Controlled tons per year
	Pneumatic Controllers
	○ Low Bleed, High Bleed, Intermittent ○ Count ○ Emission factors ○ Annual emissions

2017 Production Estimates

The 2017 production estimates provided by five of the companies helped in better estimating the expected future growth of the industry. Production estimates continue to show an upward trend, with production expecting to increase from 73 million barrels in the nonattainment area in 2014 to 130 million barrels in 2017. In addition, industry was consulted throughout the oil price crash in late 2015 and continuing through 2016 to confirm future projections and production is still forecasted to go up at this estimated rate. While production is on an upward trend, the number of active wells is expected to stay about the same as a result of a higher production capacity of horizontal wells and decline in older, low production vertical wells. Furthermore, several companies commented that it is their practice to tie in vertical wells that are within close proximity to new horizontal facilities, which enables production from older wells to go through the same stages of separation and emissions controls as newer wells.

While future year production includes oil produced from both horizontal and vertical wells, all future growth in oil and gas development is assumed to be from horizontal wells in combination with either tankless facilities or 2 and 3 stages of separation based upon discussions with the producers. Vertical well production is assumed to be declining, as is single-stage separation facilities. Tankless facilities have zero tank emissions at the well pad since there is no storage on site with all liquid production being piped to a centralized processing facility such as Anadarko's centralized oil stabilization facility. Such centralized facilities use high pressure vessels to stabilize liquids and thereby eliminate the need for multiple stages of separation at the well production site and the potential emission sources of associated equipment. The pressure vessels have no thief hatches or pressure relief valves, resulting in very low emissions. Anadarko's centralized facility is a true minor source and in the near future, tankless facilities are expected to handle a majority of production for many of the larger producers in the DJ.

Development of 2014 Emission Factors (Based on Five of the Top Producers)

From the 2014 site specific emission data provided by the producers, total annual tons were broken out by well orientation and stages of separation and were then divided by production for each of the subcategories to get new EFs in lbs/bbl. These factors took into account advancements in technology as a result of federal New Source Performance Standards (NSPS) regulations and Colorado Regulation No. 7.

For five of the top producers, these 2014 emissions factors were then applied to their 2017 projected production resulting in company specific emissions. The 2014 emissions and production from these top five companies were then summed by subcategory to come up with a weighted EF broken out by well type and stages of separation to be applied as region EFs. Table 7 shows the weighted 2014 VOC EFs for the five producers. The region wide average EFs ranged from 0.00 to 6.03 lb/bbl for horizontal wells and 7.61 to 13.70 for vertical wells. Due to the data provided being for the full 9-county nonattainment area, a factor of 90.2% was applied to the production and emissions totals to get the totals for the nonattainment area (NAA). This percentage was derived based on the 2014 production in the NAA (63.25M bbls) divided by the 2014 production in the full 9-county area (70.13M bbls).

In developing the 2014 emission factors, one of the top six producers was omitted from the development of the emissions factors for the other five top producers due to mutual concern with the validity of some site specific EFs. Therefore, this company's emissions were calculated separately with the default EF of 13.7 lbs/bbl assumed at several sites. Including these default values in the 2014 weighted EFs skewed the average somewhat. Therefore, the 2014 emission factors for this company were calculated independently and not included in estimating the weighted factors. Their 2017 emissions were, however, included in the inventory provided below in Table 8 for the top 6 produce

Table 7 – Development of 2014 Emission Factors Based Upon Well Type and Stages of Separation

Companies	Well Type	Stages of Separation	2014 Oil Production (bbl)	2014 Uncontrolled VOC Emissions (lbs)	2014 Uncontrolled VOC Emissions Factors (lbs/bbl)
Top 5	Horizontal	tankless	4,246,585	0	0.00
		1	5,261,608	31,718,343	6.03
		2	10,061,583	17,486,284	1.74
		3	22,075,307	4,751,892	0.22
		Total	41,645,083	53,956,519	
	Vertical	1	3,108,050	31,911,811	10.27
		2	2,144,057	16,324,523	7.61
		3	4,353	59,641	13.70
		Total	5,256,460	48,295,974	
9-County Area	TOTAL		46,901,543	102,252,493	
NAA	90.20%	42,302,847	92,226,636		

2017 Emissions Estimates for Top Six Producers

To project 2017 uncontrolled VOC emission estimates, calculated 2014 EFs were applied to 2017 production estimates by subcategory for each producer. Equation 2 is the formula used to calculate 2017 controlled VOC emissions for condensate tanks. To estimate the controlled emissions, a 90 percent system-wide control requirement contained in Reg. 7 was assumed as was an 83 percent RE for single-stage separation and 86 percent RE for two and three stage separation. This resulted in a total control rate of 74.7% or 77.4% based on stages of separation.

Equation 2

$$\text{Emissions (tpd)} = 2017 \text{ Production} \left(\frac{\text{bbls}}{\text{yr}} \right) \times EF \left(\frac{\text{lbs}}{\text{bbl}} \right) \times \frac{1 \text{ ton}}{2000 \text{ lbs}} \times \frac{1 \text{ yr}}{365 \text{ days}} \times (1 - (90\% \times RE\%))$$

Table 8 – Top Six Producers: 2014 and 2017 Production and 2017 Emissions Estimates

Companies	Well Type	Stages of Separation	2014 Oil Production (bbl)	2017 Oil Production (bbl)	2017 Uncontrolled VOC Emissions (tpd)	Control Rate (%)	2017 Controlled VOC Emissions (tpd)
Top 6	Horizontal	tankless	10,217,913	52,247,476	0.00	0.0%	0.00
		1	11,380,125	8,211,955	84.59	74.7%	21.40
		2	11,971,013	28,972,707	86.55	77.4%	19.56
		3	26,382,023	26,689,883	35.22	77.4%	7.96
		Total	59,951,074	116,122,020	206.36		48.92
	Vertical	1	6,659,910	5,217,456	68.39	74.7%	17.30
		2	2,533,845	1,667,938	17.66	77.4%	3.99
		3	12,732	0	0.00	77.4%	0.00
		Total	9,206,486	6,885,393	86.05		21.29
9-County Area	TOTAL		69,157,560	123,007,413	292.42		70.22
NAA	90.20%	62,376,662	110,946,536	263.74		63.33	

2017 Emissions Estimates for Rest of Producers

Because of a lack of site specific data for the smaller producers in the DJ basin, discussions took place with COGA and its smaller members to estimate future production and technology use among these producers. Consistent with the production increases projected by the top producers, estimates for this segment also projected production would increase 74.5% from 2014 to 2017. COGA confirmed that there would be a similar decline in vertical well production and increase in horizontal well production.

Among these companies, one area where the rest of the producers projections deviated from the top producers was that new production would only be utilizing one or two stages of separation. They were not projecting they would be going to three stages of separation or tankless facilities within the timeframe of this SIP.

For the smaller producers, the weighted 2014 EFs from Table 7 were applied to estimate 2017 future year projected production. It was estimated that nearly all of the future production would be from stage 2 horizontal wells with a 20% decline in vertical production and stage 1 horizontal production. Table 9 provides the breakout for the remaining producers in the DJ basin. The same controls were applied to the rest of the producers as were applied to the larger producers (i.e. a 90 percent system-wide control; 83 percent RE for single-stage separation and 86 percent RE for two and three stage separation).

Table 9 – Weighted 2014 Emission Factors Applied to Smaller Producers

Companies	Well Type	Stages of Separation	2014 Oil Production (bbl)	2017 Oil Production (bbl)	2014 Uncontrolled VOC Emissions Factors (lbs/bbl)	2017 Uncontrolled VOC Emissions (tpd)	Control Rate (%)	2017 Controlled VOC Emissions (tpd)
Remainder in NAA Counties	Horizontal	1	2,051,556	1,641,245	6.03	13.56	74.7%	3.43
		2	8,206,224	17,747,313	1.74	42.30	77.4%	9.56
		Total	10,257,780	19,388,558		55.86		12.99
	Vertical	1	1,102,678	882,142	10.27	12.41	74.7%	3.14
		2	472,576	378,061	7.61	3.94	77.4%	0.89
		Total	1,575,254	1,260,203		16.35		4.03
9-County Area	TOTAL		11,833,034	20,648,761		72.21		17.02
NAA	90.20%		10,672,805	18,624,150		65.13		15.35

The summation of Table 8 and Table 9 comprise the 2017 VOC emission inventory for condensate tanks and is provided in Table 10. Based upon the 2011 emissions inventory, VOC emissions from condensate tanks are projected to decrease by 64% by 2017 due to the advancements in technology and more stringent regulations on this industry.

Table 10 - 2017 VOC Emissions Inventory - Oil and Gas Condensate Tanks

Companies	Well Type	Stages of Separation	2014 Oil Production (bbl)	2017 Oil Production (bbl)	2017 Uncontrolled VOC Emissions (tpd)	Control Rate (%)	2017 Controlled VOC Emissions (tpd)
All	Horizontal	tankless	10,217,913	52,247,476	0.00		0.00
		1	13,431,681	9,853,200	98.15	74.7%	24.83
		2	20,177,237	46,720,020	128.85	77.4%	29.12
		3	26,382,023	26,689,883	35.22	77.4%	7.96
		Total	70,208,854	135,510,578	262.22		61.91
	Vertical	1	7,762,587	6,099,598	80.80	74.7%	20.44
		2	3,006,421	2,045,998	21.60	77.4%	4.88
		3	12,732	0	0.00	77.4%	0.00
		Total	10,781,740	8,145,596	102.40		25.32
9-County Area	TOTAL		80,990,594	143,656,174	364.63		87.24
NAA	90.20%		73,049,467	129,570,686	328.87	76.1%	78.69
Reduction from 2011 (216 tpd VOC)							64%
							137.31

There are no direct NO_x or CO emissions from condensate tanks, however there are emissions associated with the flare used to combust emissions emanating from the tank, which are included in Table 11.

Table 11 - 2017 Oil and Gas Condensate Tank Emissions

Description	2017 (tpd)		
	VOC	NO _x	CO
Condensate Tanks	78.7	0.6	2.3

1.4 OIL AND GAS AREA SOURCES

Oil and gas area sources include a wide variety of categories such as engines, truck loading, pneumatic devices, fugitives, fracing completions, and blowdowns. Table 12 provides the summary inventory for area sources for both 2011 and 2017.

Table 12 – 2011 and 2017 Oil and Gas Area Source Inventory

Description	VOC (tpd)			NO _x (tpd)			CO (tpd)		
	2011	2017	Δ	2011	2017	Δ	2011	2017	Δ
Area Sources - Subtotal	48.9	59.0	10.0	22.2	44.6	22.3	12.9	31.4	18.5

1.4.1 2011 Oil and Gas Area Source Inventory Development Process

For 2011, the oil and gas area source emissions were derived from the 3–State Study/ENVIRON 2011 update and are provided in detail in Table 13. The 2011 inventory was based on the 2006 Independent Petroleum Association of Mountain States (IPAMS) Survey grown to 2011 based upon production data from the COGCC. Emissions associated with non-road equipment used in the oil and gas sector are included in EPA's non-road model (NONROAD2008) and are included in the non-road mobile source inventory. Therefore, they have been removed from the oil and gas source inventory to avoid double counting. Fracing was also not included in the 2011 inventory due to limited fracing activity in that year as the technology was new to the DJ basin.

Table 13 - 2011 Oil and Gas Area Source Inventory

Description	2011 (tpd)		
	VOC	NO _x	CO
Oil and Gas Area Sources			
Drill rigs	0.7	11.3	5.9
Exempt engines	0.6	8.1	5.2
Fugitives	21.3		
Heaters	0.1	1.6	1.3
Misc. (spills, workover rigs, etc.)	0.5	1.3	0.5
Pneumatic devices	11.8		
Pneumatic pumps	2.4		
Truck loading of condensate liquid	3.8		
Venting - blowdowns	4.6		
Venting - initial completions and recompletions	3.2		
Water tank losses	0.0		
Subtotal	48.9	22.2	12.9

1.4.2 2017 Oil and Gas Area Source Inventory Development Process

For 2017, emissions projections were provided by five of the top six producers, which took into account estimated future production, well count, and technology advancements as a result of state and federal rules. The data provided, previously presented in Table 6, was also the basis for developing the 2017 inventory for area sources. This data was summed for the top five producers and each category was scaled-up for the rest of the producers using either 2017 production estimates or well count estimates depending on the category. A breakout of the scaling parameters and factors used are provided in Table 14 and a breakout of emissions by category is provided in Table 15. The scale-up factors were based on the projected 2017 production or number of active wells of the entire DJ basin divided by the projected production or number of wells (see Equation 3).

Equation 3

		<u>Wells</u>	<u>Production</u>	
<i>Scale-Up Factors</i>	= $\frac{2017 \text{ All Companies}}{2017 \text{ Major Producers (5 Companies)}}$ =	<u>22,310</u> 11,029	<u>143,656,174</u> 84,898,764	
		↓	↓	
		202%	169%	

Table 14 – Scale-Up Parameters and Factors for Area Source Categories

Parameters		
Scaled-Up By Production	Scaled-Up by Well Count	
• H2O Tank Control (tpy) • Loadout Control (tpy) • Oil Tank Control (tpy) • SEP Control (tpy)	• Burner (tons/ozone season) • Drilling (tpy) • Engines (tpy) • Fracing Completions (tpy) • Pneumatic Controller Low Bleed (tpy) • Pneumatic Controller Intermittent (tpy)	• Pneumatic Pump (tpy) • Venting Completions (tpy) • Well Unload Total (tpy)

Oil and gas area source data provided by the producers were provided on an annual basis for the full 9-county area. One exception was burners for which emissions were provided for only during the ozone season. Data was scaled-up for the rest of the producers, divided by 365 to get daily emissions, and multiplied by 90.2% to scale emissions down to the nonattainment area. A 60% control factor was applied to fugitive emission sources, which is considered Reasonably Available Control Technology (RACT) level of control for fugitive sources subject semi-annual monitoring. Miscellaneous sources were held constant from 2011 to 2017.

Table 15 – 2017 Oil and Gas Area Source Fugitive and Non-Fugitive Emissions

	VOC (tpd)	NO _x (tpd)	CO (tpd)
NON-FUGITIVES			
Separator Control	12.44	-	-
Water Tank Control	1.39	0.04	0.11
Well Unload Total	3.94	-	-
Burner	0.42	7.75	6.52
Pneumatic Pump	0.38	-	-
Loadout Control	8.36	0.04	0.06
Pneumatic Controller Low Bleed	0.09	-	-
Pneumatic Controller Intermittent	21.52	-	-
Drilling	1.40	13.64	5.06
Venting Completions	0.68	0.06	-
Fracing Completions	0.91	13.49	-
Engines	3.82	12.94	22.51
Misc. (spills, workover rigs, etc.)	0.55	1.44	0.57
TOTAL (w/o Fugitives)	55.91	49.40	34.82
NAA 2017 Total (90.2%)	50.43	44.56	31.41
FUGITIVES			
Uncontrolled 2017 Fugitives Adjusted by Well Count	21.35		
Controlled Fugitives in NAA (tpd) (EPA RACT - 60%)	8.54		
TOTAL 2017 NAA (w/ Controlled Fugitives)	58.96	44.56	31.41

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Appendix A (continued)

Equipment Information (continued)		Completions/Recompletions (continued)
H2O Tanks	H2O Tank NOx EF (lb/lb VOC)	Compl Vent Duration (MCF)
	H2O Tank NOx EF (lb/MMBtu)	Compl Vent DRE (%)
	H2O Tank Cntrl NOx (tpy)	Compl Vent Gas Avg VOC Mol (%)
	H2O Tank Avg NOx Emis Rate (lb/hr)	Compl Vent VOC (tpy)
	H2O Tank CO EF (lb/lb VOC)	Compl Vent Avg. VOC (lb/hr)
	H2O Tank CO EF (lb/MMBtu)	Compl Vent NOx EF (lb/MMBtu)
	H2O Tank Cntrl CO (tpy)	Compl Vent Cntrl NOx (tpy)
	H2O Tank Avg CO Emis Rate (lb/hr)	Compl Vent Avg NOx Emis Rate (lb/hr)
Loadouts	Loadout AIRS	* 2014 data provided by top 6 producers (Anadarko, Bonaza Creek, Encana, Noble, PDC, and Whiting) ; 2017 projections provided by top 5 producers (Anadarko, Bonaza Creek, Encana, PDC, and Whiting)
	Loadout Volume (bbl)	
	Loadout Control Type	
	Loadout DRE (%)	
	Loadout Uncntrl VOC EF (lb/bbl)	
	Loadout Cntrl VOC (tpy)	
	Loadout Avg VOC Emis Rate (lb/hr)	
	Loadout NOx EF (lb/lb VOC)	
	Loadout NOx EF (lb/MMBtu)	
	Loadout Cntrl NOx (tpy)	
	Loadout Avg NOx Emis Rate (lb/hr)	
	Loadout CO EF (lb/lb VOC)	
	Loadout CO EF (lb/MMBtu)	
	Cntrl Loadout Tank CO (tpy)	
	Loadout Avg CO Emis Rate (lb/hr)	
Pneumatic Controllers	Pneumatic Actuation Gas VOC mol %	
	Pneum Cntrlr Low Bleed Count	
	Pneum Cntrlr Low Bleed EF (scf/device-hr)	
	Pneum Cntrlr Low Bleed VOC (tpy)	
	Pneum Cntrlr Low Bleed Avg VOC Emis Rate (lb/hr)	
	Pneum Cntrlr High Bleed Count	
	Pneum Cntrlr High Bleed EF (scf/device-hr)	
	Pneum Cntrlr High Bleed VOC (tpy)	
	Pneum Cntrlr High Bleed Avg VOC Emis Rate (lb/hr)	
	Pneum Cntrlr Intermittent Count	
	Pneum Cntrlr Intermittent EF (scf/device-hr)	
	Pneum Cntrlr Intermittent VOC (tpy)	
	Pneum Cntrlr Intermittent Avg VOC Emis Rate (lb/hr)	
	Pneum Pump Count	
	Pneum Pump EF (scf/device-hr)	
	Pneum Pump VOC (tpy)	
	Pneum Pump Avg VOC Emis Rate (lb/hr)	
Well Unload	Well Unload Total VOC (tpy)	
	Well Unload Gas Avg VOC Emis Rate (lb/hr)	



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December 4, 2015

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2015-0216

Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" at 80 FR 56577 (September 18, 2015).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane

emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, carbon dioxide (CO₂) emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (NSPS Subpart OOOOa, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

A handwritten signature in black ink that reads "Howard J. Feldman". The signature is written in a cursive, slightly slanted style.

Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

Attachment

API Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry

December 4, 2015

Docket ID No. EPA-HQ-OAR-2015-0216

Executive Summary

As detailed in our comments, API has numerous concerns with EPA's draft Control Techniques Guideline (CTG) for the Oil and natural gas (O&G) sector. EPA has indicated the desire to finalize the draft CTG in early 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments. This is an unrealistic schedule for issuing a complex guidelines with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final guidance to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of EPA's draft Reasonably Available Control Technology (RACT) recommendations and the associated model regulatory text. The one-size-fits-all approach is not appropriate for an industry that varies greatly in the type, size and complexity of operations. EPA has supported its RACT recommendations using economic studies based on "average model facilities" without determining whether the resulting control requirements are appropriate for the entire range of sources included in the source category. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

EPA Must Develop Applicability Thresholds Based On VOC Content To Avoid Requiring Controls That Are Clearly Not Cost Effective And Not RACT For Areas With Low-VOC Gas

Issue – By performing all RACT analyses using a single representative gas composition, EPA has recommended RACT for several fugitive sources that will result in cost effectiveness values considerably higher than EPA considers acceptable in many areas of the U.S. The volatile organic compound (VOC) content of the gas at a site is directly related to the VOC emissions, and thus, the VOC emission reduction when controls are applied. By using a single gas composition for all RACT analyses, EPA did not properly evaluate the VOC cost effectiveness for dry gas, coal bed methane, and other areas that have low-VOC gas. API has performed an analysis that provides recommendations for these thresholds that are technically sound.

Recommendation – Include VOC content applicability thresholds that ensure that areas with low VOC gas are not subject to controls that are not cost effective.

Refer to Section 2.0 for detailed comments on this matter.

Storage Vessel Monitoring Requirements

Issue – The CTG model rule includes onerous continuous parameter monitoring requirements for storage vessels that are considerably more stringent than EPA has proposed for NSPS. The RACT monitoring requirements for storage vessels should not be more stringent than the Best System of

Emission Reduction (BSER) monitoring requirements in the NSPS. Further, EPA did not include the costs of this more stringent monitoring in the impacts assessment for storage vessels.

Recommendation – Make the continuous compliance requirements in the CTG consistent with the proposed requirements in NSPS subpart OOOOa.

Refer to Section 13.8 for detailed comments on this matter.

Fugitives At Well Sites And Compressor Stations

Issue – The draft CTG has a process that requires significant, unnecessary recordkeeping and reporting, and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation – Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Section 17.0 for detailed comments on this matter.

EPA Should Delay Finalizing the CTGs Until Six Months After NSPS OOOOa is Finalized

Issue – The CTGs and NSPS OOOO/OOOOa regulate the same type of equipment. Proposing these two actions at the same time resulted with significant inconsistencies that appear to be unintentional and would be illogical if the inconsistencies were intended. Finalizing these two actions at the same time is like to result in inconsistencies in the final actions, as well as duplication of technical errors.

Recommendation – The CTG actions can be delayed without significant impacts. EPA should delay finalizing the CTGs until six months after NSPS OOOOa is finalized.

Refer to Section 1.0 for detailed comments on this matter.

The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 Tpy VOC

Issue – The proposed rule applies the same 6 TPY VOC applicability for new storage vessels to existing storage vessels. Cost of control is higher for existing storage vessels than new storage vessels. EPA's cost estimate underestimates the retrofit costs for an existing storage vessel by ignoring other costs such as purchasing additional land to meet safety buffers for combustion devices. Some existing storage vessels would need to be replaced since they could not handle the additional pressure required for a closed vent system to a control device. These additional considerations make a 6 TPY VOC applicability threshold economically unreasonable for existing tanks.

Solution – Increase the applicability threshold to 10 – 15 TPY VOC to assure that controls are economically feasible.

Refer to Section 13.2 for detailed comments on this matter.

EPA Should Exempt Natural Gas Pneumatic Pumps That Emit At A Rate Lower Than A High Bleed Controller

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit.

Recommendation – EPA should exempt low emitting pumps, i.e. pumps that emit at a rate lower than a high bleed controller. This should include low usage equipment as well. This is consistent with the position taken in subpart OOOO and reinforced under the subpart OOOOa proposal for pneumatic controllers.

Refer to Section 15.4.1 for detailed comments on this matter.

Pneumatic Pump Control Technical Feasibility

Issue – EPA has ignored major technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should provide an exemption from the requirements to control pump emissions where it has been determined to not be technically feasible.

Refer to Sections 15.0 for detailed comments on this matter.

Common Sense Voluntary Reductions And Incentives Will Lead To Increased Early Emission Reductions

Issue – The CTGs should work in concert with the Methane Challenge Voluntary Initiative to seek common sense voluntary reductions and incentives, which will lead to increased early emission reductions. If the Administration wishes to seek additional reductions through a federal framework, the best approach would be a voluntary program without duplicative mandatory regulation. The industry is interested in participating in a well-constructed voluntary program, and has shared options for achieving substantial methane emissions reductions more rapidly than regulations would allow. Industry and EPA's incentives are aligned in desiring to keep methane in the pipeline, to reduce losses and improve product recovery. Industry members strive to evaluate options for cost effective measures to reduce emissions and implement them where they can achieve the greatest reductions. For example, EPA recently reported that total methane emissions from natural gas systems are down 11 percent since 2005 despite significant growth in production. To continue this progress and maximize the results, the industry requires flexible voluntary programs with appropriate incentives, not inflexible regulatory mandates.

Solution – Eliminate duplicative regulation of emissions.

Refer to all sections for detailed comments on this matter.

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Attachments

Attachment A - Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas	
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GENERAL COMMENTS

1.0 GENERAL PROCEDURAL AND LEGAL COMMENTS

EPA has requirements in the proposed Control Technique Guidelines (CTG) on the same sources regulated in NSPS, Subpart OOOO, including currently proposed amendments, and the proposed NSPS Subpart OOOOa. Writing two separate rules on the same equipment at the same time inevitably cause inconsistencies between the rules, as has been the case in these proposed rules. For instance, continuous parameter monitoring systems (CPMS) are required in the proposed CTGs for control devices, regardless of what type of affected source the emissions are coming from. However, NSPS Subpart OOOOa requires CPMS for emissions coming from centrifugal compressors or pneumatic pumps, but only sensory monitoring and inspection requirements for storage vessels. Discussions with EPA indicate they intended to propose the same compliance assurance in both NSPS Subpart OOOOa and the CTGs.

An existing storage vessel regulated by the CTG may be located right next to a new storage vessel regulated by NSPS, Subpart OOOOa. Requiring stringent CPMS monitoring for the existing storage vessel and visual inspections for the new storage vessel will be very confusing to both the agency inspectors and to the oil & gas industry personnel in trying to comply with the two different sets of requirements. Retrofitting existing equipment is more expensive than the respective increased cost for new equipment, thus you would expect existing equipment to have less stringent requirements than those for new equipment. The opposite occurred in the proposal. EPA widely utilized Best System of Emissions Reduction (BSER) as Reasonably Available Control Technology (RACT), which is not always supportable. However, in all cases BSER should be considered a cap to RACT (see Section 4.1).

For this reason, API requests that EPA delay finalizing the CTGs for at least six months after the NSPS, Subpart OOOOa rule has been finalized. Finalizing the NSPS first allows the requirements to be implemented during the initial equipment construction when it is most effective. Additionally, the existing CTGs are expected to have the most impact on existing equipment in new nonattainment areas designated due to the lowering of the Ozone NAAQS in October 2015. These new nonattainment areas are not expected to be finalized until October 2017. Further, the CTGs require state regulatory actions before these requirements can be implemented. Thus, delaying the finalized CTG until early in 2017 will cause no delays in implementation for these areas. The CTGs are not expected to have significant impact in existing ozone nonattainment areas, since RACT requirements are already in place (i.e. in Denver, CO; Houston, Dallas, and Beaumont, TX; etc.). Where states feel that regulatory changes are needed promptly, they can proceed with those actions based on the NSPS OOOO/OOOOa final rule.

2.0 EPA MUST DEVELOP APPLICABILITY THRESHOLDS BASED ON VOC CONTENT TO AVOID REQUIRING CONTROLS THAT ARE CLEARLY NOT COST EFFECTIVE AND NOT RACT FOR AREAS WITH LOW-VOC GAS

CTGs are required by the CAA to help an area obtain the NAAQS. As such, CTGs cannot consider the benefits of methane reductions in the economic analysis of control options. As proposed, the CTG would require controls in production fields (i.e. coalbed methane or dry gas fields) where little to no VOC reductions would occur. EPA should adopt minimum VOC thresholds for fugitive monitoring, pneumatic pumps, pneumatic controllers and centrifugal

compressors, below which no controls would be required to maintain the cost effectiveness of controls where little or no benefits to NAAQS attainment would occur.

2.1 Cost Effectiveness Is Key Element Of RACT

As stated in Chapter 1 of the draft CTG, EPA defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” 44 FR 53761 (September 17, 1979). Historically, the primary measure that EPA has relied upon to assess economic feasibility is the cost of the emission reduction in relation to the level of emission reduction. This “cost-effectiveness” is calculated by dividing the annual costs of the control (including capital recovery along with operating and maintenance costs) by the annual emission reduction.

EPA calculated and showed the cost effectiveness for every option considered. The cost effectiveness values for the fugitive emission sources that EPA recommended as RACT are summarized in Table 2-1.

Table 2-1 EPA VOC Cost Effectiveness Values from CTG

Source	Cost Effectiveness (\$/ton VOC reduced)	
	without savings	with savings
Reciprocating Compressor (Gathering and Boosting Station)	\$1,132	\$298
Reciprocating Compressor (Processing Plant)	\$334	(\$500)
Pneumatic Controller (Well Site)	\$210	(\$627)
Pneumatic Controller (Processing Plant)	\$2,807	\$1,970
Pneumatic Pump (Diaphragm) – Existing Control Device	\$312	\$312
Pneumatic Pump (Piston) – Existing Control Device	\$2,840	\$2,840
Equipment Leaks (Processing Plant)	\$2,844	\$2,010
Fugitive Emissions (Natural Gas Well Site)	\$2,945	\$2,111
Fugitive Emissions (Oil Well Site)	\$12,294	\$11,460
Fugitive Emissions (Gathering and Boosting Station)	\$2,710	\$1,876

It is evident that EPA relied on the cost effectiveness in determining the economic feasibility of controls for the oil and natural gas industry, as every section of the document that discusses the recommended RACT level of control includes a discussion of cost effectiveness. For example, on pages 7-17 and 7-18 of the CTG, EPA states:

“Our rationale for selecting 95 percent control when there is an existing control device is that, as presented in Table 7-4 in section 7.3.1.4 of this chapter, the VOC cost of control when an existing combustion device is available on-site was estimated to be \$312/ton for diaphragm pumps and \$2,850/ton for piston pumps. As presented in Table 7-6 in section 7.3.1.5 of this chapter, the VOC cost of control when an existing VRU is available on-site was estimated to be a cost savings for diaphragm pumps and \$2,007/ton for piston pumps. We consider these costs to be reasonable. Requiring control where there is not an existing control device on-site was not considered to be reasonable available technology, and the costs per ton of VOC reduced are estimated at greater than \$20,000 per ton of VOC reduced for diaphragm pumps and over \$200,000 per ton of VOC reduced for piston pumps.”

This citation also shows that there are levels at which EPA considers the cost effectiveness for VOC to be reasonable, as well as levels that EPA considers to be unreasonable. Historically, EPA has avoided establishing a bright line that separates reasonable versus unreasonable, but past EPA decisions do provide insight into what constitutes reasonable.

The best and most relevant example of EPA's view of a reasonable cost effectiveness level for VOC for the oil and natural gas industry was provided in EPA's final decision related to the 4 tpy alternative emission limitation for storage vessel affected facilities under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429).

"... our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately \$5,100 per ton. This cost increases to approximately \$6,900 per ton at an emission rate of 3 tpy, and to approximately \$10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of \$5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy."

"In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy."

There are several key facts worthy of note regarding these statements related to establishing a reasonable cost effectiveness level for RACT for fugitive sources from this industry.

- 1) This decision was specific to the exact industry that is covered by the oil and natural gas CTG.
- 2) The 2007 rulemaking cited as precedent was for fugitive sources analogous to most of the sources covered in the CTG. Specifically, this rulemaking was for "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; Final Rule."
- 3) This threshold was used by EPA to establish a cost effectiveness level considered unreasonable for BSER, which is by definition, more stringent than RACT. Therefore, based on clear precedent summarized above, EPA must consider any cost effectiveness value greater than \$5,700 per ton of VOC reduction to be unreasonable for the purpose of recommending RACT for fugitive source the oil and natural gas industry.

2.2 Cost Effectiveness Of Recommended Fugitive RACT For Oil Wells Is Unreasonable

Given this fact, an obvious first observation is that the cost effectiveness for EPA's recommended RACT for fugitive emissions at oil wells is well above this reasonableness threshold. EPA provided a vague and unsupportable rationale for ignoring the results of their own analysis and recommending level of control estimated to have a cost effectiveness of \$11,460 (considering savings), which is more than double the level previously determined to be unreasonable (see

pages 9-32 and 9-33 of the CTG). Without any consideration of any other factors discussed below, EPA must not finalize a recommendation of any fugitive leak monitoring program as RACT for fugitive emissions at well site. This is discussed in more detail in section 17.0.

2.3 Variation In VOC Content Of Gas Directly Impacts Emission Reductions And Cost Effectiveness

A lower VOC content would reduce the emission reduction achieved by a technology, thus increasing the cost effectiveness. For instance, consider a fugitive emission source where the cost of reducing the emissions is \$10,000 per year. If the VOC emissions reduction for this measure at a site with a gas stream consisting of 20% VOC by weight is 5 tons per year, the cost effectiveness would be \$2,000 per ton. However, applying the same reduction measure to a site where the gas content of the stream is 5% VOC by weight, the VOC emission reduction would be reduced to 1.25 tons per year and the cost effectiveness would increase to \$8,000. Therefore, this difference in VOC content causes the cost effectiveness to be reasonable (by EPA's previous determination) at one site and unreasonable at another.

All the analyses in the CTG were conducted using a single representative gas composition.¹ For oil and natural gas production, this gas composition included 6.8% VOC by volume and 18.3% VOC by weight.

API notes that the documentation for the selection of this representative composition is lacking. In Table 1 of the 2011 EC/R memorandum, gas composition information from a variety of sources was presented. After a review of the available data, the outcome was that only data provided by the Gas Research Institute (GRI) data during the 1995 MACT development was used to calculate the representative gas compositions. Part of the rationale for relying on this GRI data was that a comparison of the GRI data to the other information showed that the GRI data was representative. However, Table 1 and the paragraph that describes this conclusion are severely flawed. For example, the memo states "For production, the 1995 GRI data is well within the ranges of the other data sources, which range from 1.19 to 11.6 percent for VOC by volume." However, the maximum VOC content shown in Table 1 for the other data sources is 5.7 volume percent. Also, Table 1 presents the average VOC content of the other data sources as 3.5 volume percent, as compared to an average of 3.66 volume percent for the GRI data. However, in Table 5 of the EC/R memorandum (which summarizes the GRI data) the sum of the volume percentages of the VOC components is 6.8 percent. Not only does this not match the 3.66 percent provided as the average in Table 1, it is also higher than the maximum VOC content of all the other data sources evaluated. This raises questions about the overall credibility of the analysis leading to EPA's representative composition. It also indicates that EPA may have significantly overestimated VOC emissions when this representative composition was used. In order for the public to have confidence in EPA's overall impacts assessment, EPA must explain these discrepancies in the documentation of the representative analysis and make corrections as necessary.

Despite the significant errors discussed above in EPA's documentation, API believes that the resulting representative gas composition (containing 6.8 percent VOC by volume and

¹ Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

18.3 percent VOC by weight) is a reasonable portrayal of an “average” gas composition across the U.S. However, API strongly disagrees with the use of this representative composition to establish a universal RACT recommendation. It is inappropriate to use these general averages for determining whether particular existing oil and natural gas sources should be subject to VOC regulation and what is a cost-effective level of RACT control. The gas compositions in oil and natural gas fields in ozone nonattainment areas and the transport region where these RACT regulations will apply vary widely. In many areas, the VOC content is considerably lower than level in EPA's representative composition.

2.4 Evaluation Of Cost Effectiveness For Sites In EPA's Dataset

As noted above, the average VOC content for the GRI data set chosen by EPA to establish the representative composition was 6.8% by volume. The cost effectiveness calculated by EPA for the recommended RACT level of control for fugitive emissions from gas wells, using this representative composition, was \$2,111 (considering savings). EPA considers this level to be reasonable. However, the VOC content of the gas compositions for the individual sites in the GRI data set ranged from 0.59% to over 28% by volume. This significant difference in gas composition would have a tremendous impact on the emission reductions, and thus, the associated cost effectiveness. Table 2-2 estimates the cost effectiveness values for each of the sites in EPA's GRI data set.

Table 2-2 Estimated Cost Effectiveness for Recommended RACT for Fugitive Emissions at Gas Well Sites at Sites in EPA's Gas Composition Data Set

Site	VOC Content (vol %)	Estimated Cost Effectiveness
Representative Composition	6.82%	\$2,111
GRI1	0.59%	\$24,414
GRI2	2.20%	\$6,547
GRI3	3.93%	\$3,665
GRI4	28.13%	\$512
GRI5	7.15%	\$2,015
GRI6	8.64%	\$1,667
GRI7	7.01%	\$2,055
GRI8	10.09%	\$1,428
GRI9	6.22%	\$2,316
GRI10	2.41%	\$5,977
GRI11	3.21%	\$4,487
GRI12	2.30%	\$6,263

Considering the actual compositions from EPA's own dataset shows that the recommended RACT level for fugitive emissions as gas well sites would result in many gas well sites being subject to controls that have cost effectiveness values above the \$5,700 level which EPA has previously determined to be unreasonable for this industry. In fact, four of the twelve sites in EPA's data set, or 25%, would incur what EPA itself has determined are unreasonable costs when considering the VOC emission reduction. This includes one site that would be required to install controls at a cost effectiveness of over \$24,000 per ton of VOC reduction.

2.5 Evaluation Of Cost Effectiveness With Varying VOC Composition In Gas

In order to demonstrate the overall impact of varying VOC content on cost effectiveness, API conducted a succinct analysis for the fugitive emission sources at oil and natural gas sites covered by the CTG. This analysis was conducted using two different costs. The first analysis was conducted using EPA's estimated annual costs as provided in the CTG without adjustment. However, as discussed throughout this document, API believes EPA's costs in the CTG underestimated the actual impact that will occur in several instances. Therefore, the second analysis uses API's updated cost estimates.

2.5.1 Analysis Using EPA Costs

As noted above, EPA's representative gas composition consisted of 6.8% VOC by volume and 18.3% VOC by weight. The cost effectiveness values that were provided in Table 2-1 were based on emissions calculated using these weight percentages. Cost effectiveness values were calculated at varying concentrations of VOC by assuming a linear relationship between VOC emission reductions and the VOC content. Figure 2-1 through Figure 2-4 show the results of this analysis. For reciprocating compressors at processing plants and pneumatic controllers at well sites, EPA estimated that there would be net savings due to the recovery of natural gas. These sources were not included in this analysis.

Figure 2-1 CTG Cost of Control – Reciprocating compressors at Gathering and Boosting Stations

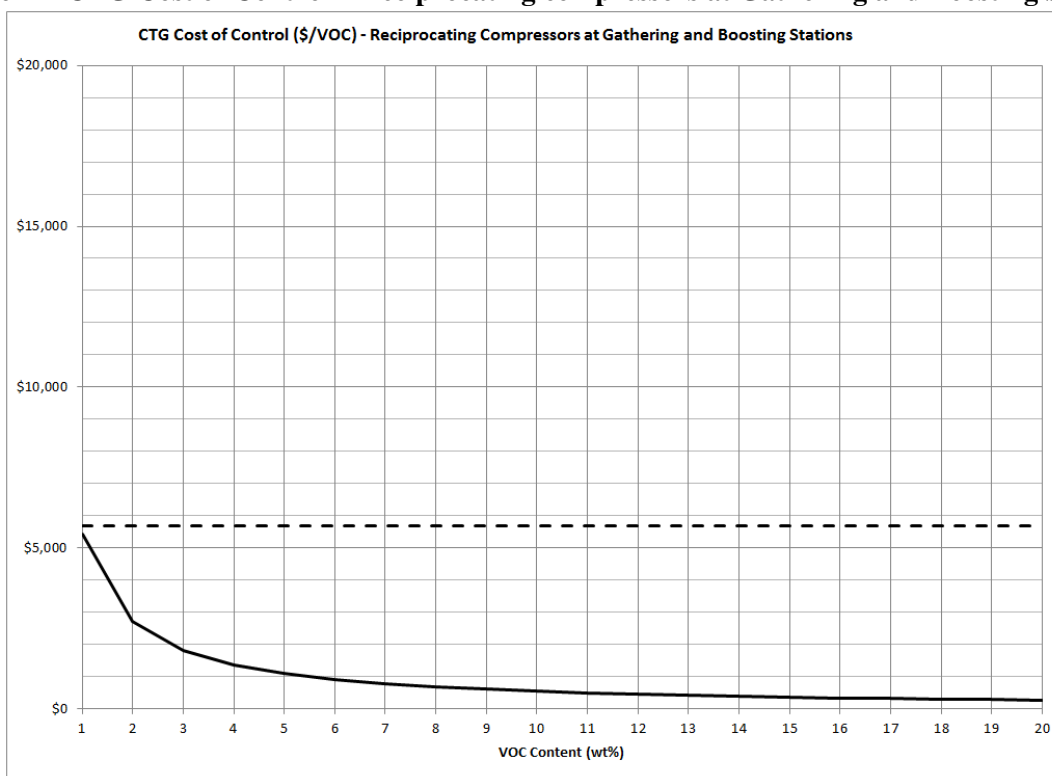


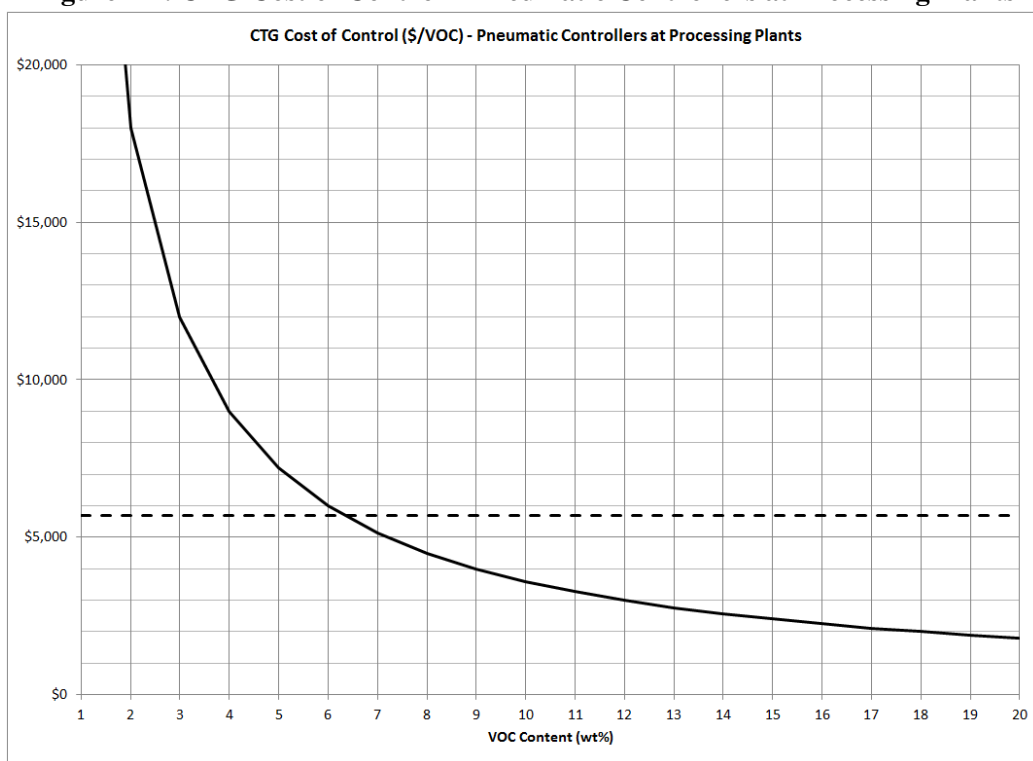
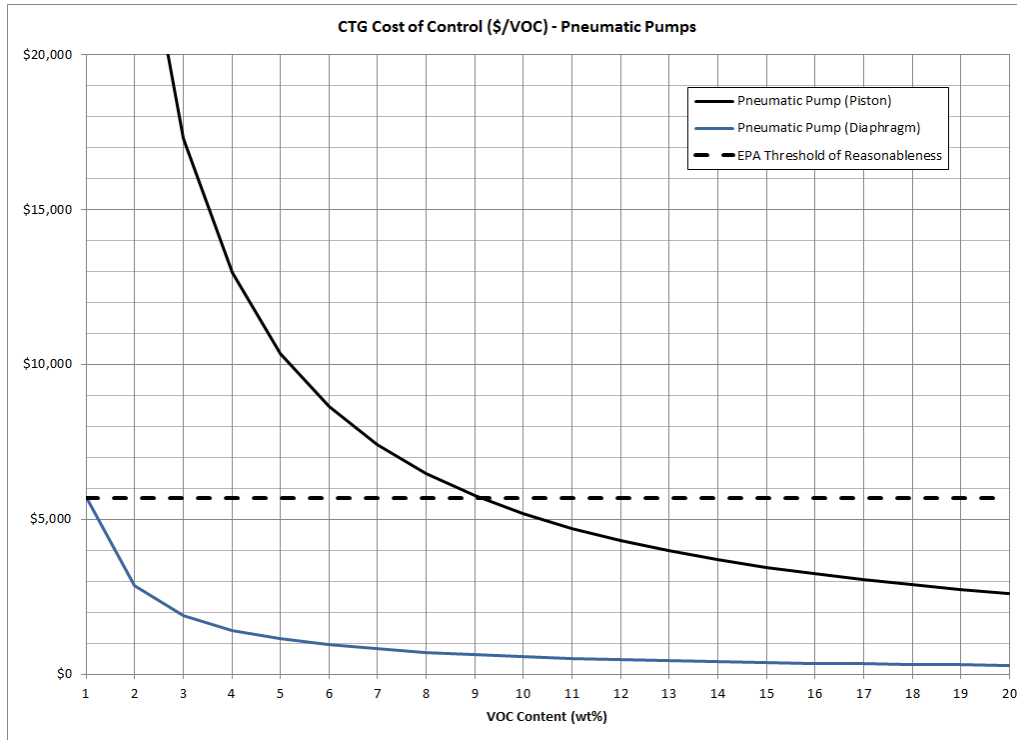
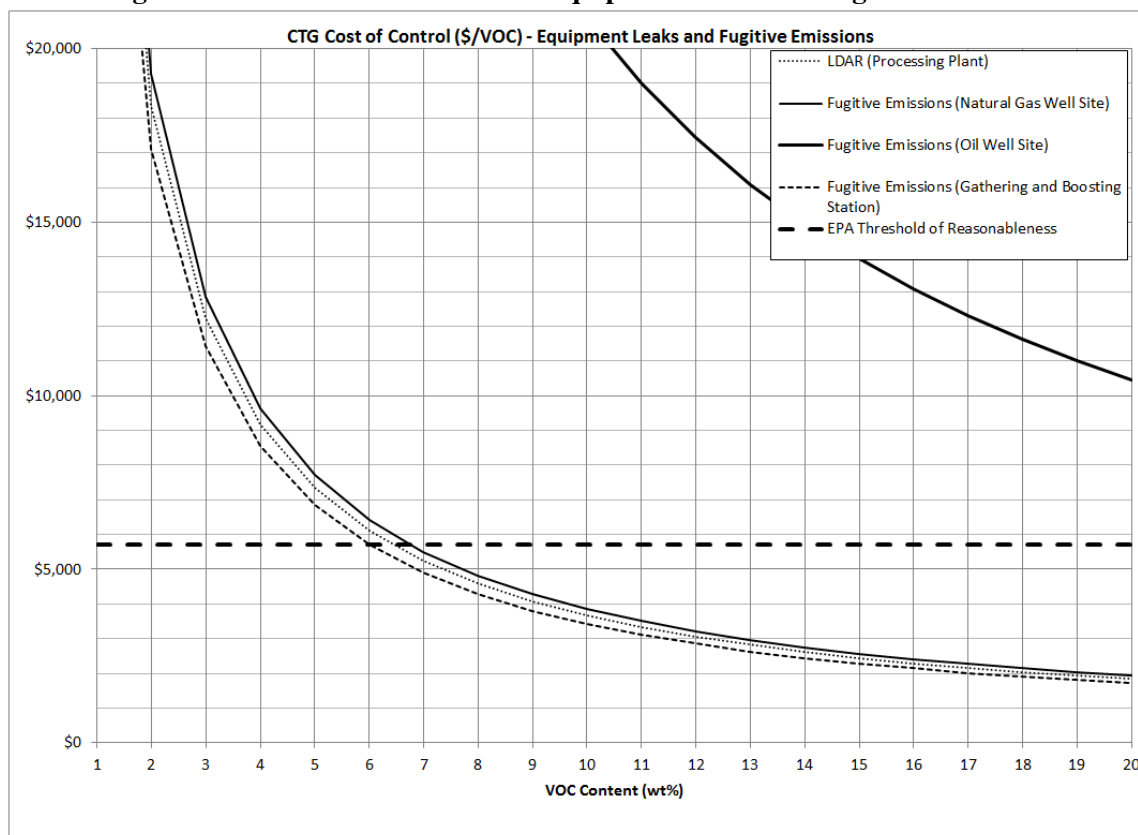
Figure 2-2. CTG Cost of Control – Pneumatic Controllers at Processing Plants**Figure 2-3. CTG Cost of Control – Pneumatic Pumps**

Figure 2-4. CTG Cost of Control – Equipment leaks and Fugitive Emissions

The conclusion of this analysis based on the EPA costs, are as follows:

- For reciprocating compressors at gas processing plants, the cost effectiveness is below \$5,700 for VOC concentrations down to 1% by weight.
- The cost effectiveness for fugitive emissions control at oil well sites is greater than \$5,700 and thus unreasonable at all VOC concentrations.
- For pneumatic controllers and LDAR at gas processing plants, pneumatic piston pumps, and fugitive emissions at natural gas well sites and gathering and boosting stations, the cost effectiveness rises above \$5,700 at VOC concentrations about 6 and 7% by weight.

2.5.2 Analysis Using Updated API Costs

For pneumatic pumps and fugitive emissions from well sites, EPA significantly underestimated the cost of control. API provides detailed analyses of these costs in sections 15.0 and 17.3 for pneumatic pumps and fugitives, respectively. Table 2-3 shows the difference in the annual costs estimated by EPA and the corrected costs based on API members' extensive experience installing and implementing these controls.

Table 2-3. Comparison of EPA and Updated API Cost Estimates

Source	Annual Costs (including savings)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	\$4,359
Pneumatic Pump (Piston)	\$201	\$5,024
Fugitive Emissions (Gas Well Sites)	\$1,599	\$7,712
Fugitive Emissions (Oil Well Sites)	\$2,079 ^a	\$8,192 ^a

^a EPA cost is for semi-annual OGI program. API cost is for annual program.

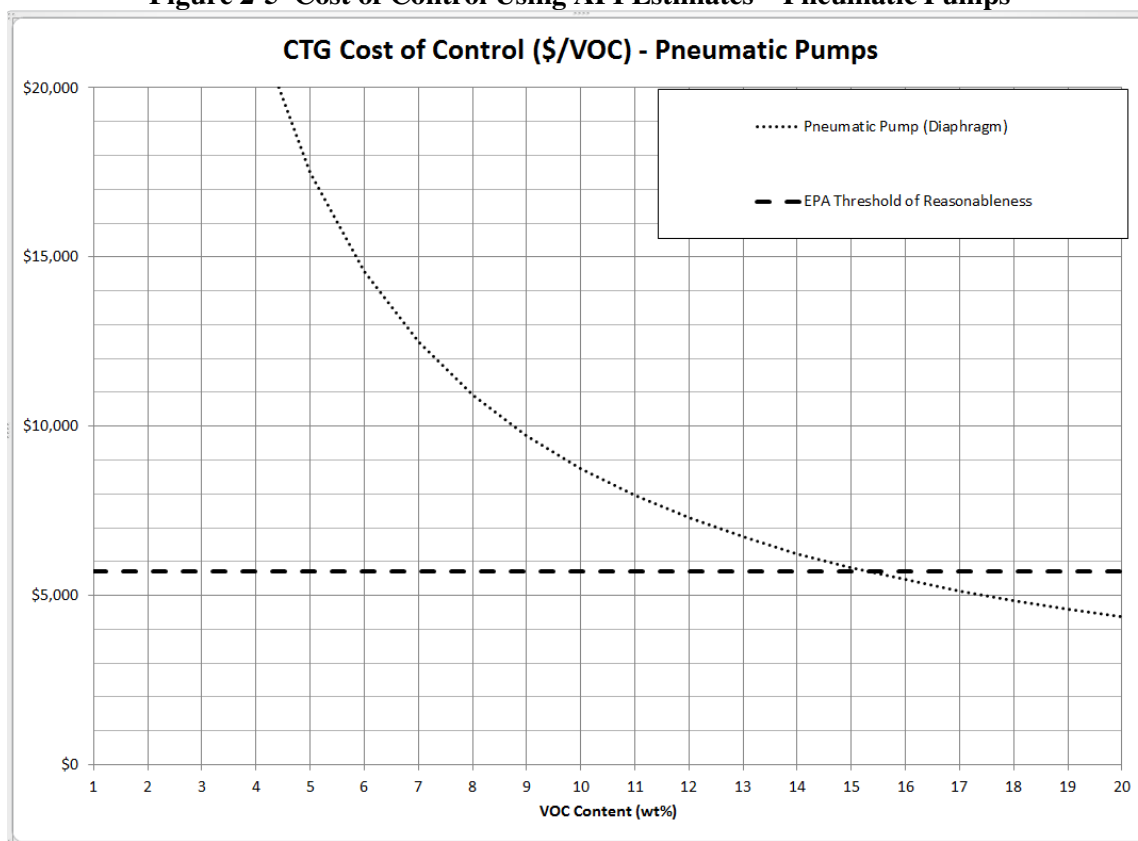
Table 2-4 shows the cost effectiveness calculations using API's updated annual costs. Note that these are based on the VOC emission reductions estimated by EPA using the representative gas composition.

Table 2-4. Comparison of EPA and Updated API Cost Effectiveness Calculations

Source	Cost Effectiveness (\$/ton VOC reduction)	
	EPA	API
Pneumatic Pump (Diaphragm)	net savings	\$4,790
Pneumatic Pump (Piston)	\$2,007	\$50,240
Fugitive Emissions (Natural Gas Well Site)	\$2,111	\$10,147
Fugitive Emissions (Oil Well Site)	\$11,460 ^a	\$45,511 ^a

^a EPA cost is for semi-annual OGI program. API cost is for annual program.

As seen in Table 2-4, the cost effectiveness values for EPA's draft RACT recommendations for fugitive emissions programs at well sites and for pneumatic piston pumps are well above EPA's reasonableness threshold of \$5,700/ton. The diaphragm pneumatic pumps are below this threshold. However, this cost effectiveness is based on the 18.3% by weight VOC content in EPA's representative composition. As discussed above, many areas have gas compositions much lower than this level. Figure 2-5 illustrates the cost effectiveness at different VOC composition levels. As can be seen, the cost effectiveness crosses the \$5,700 reasonableness threshold at around 15% VOC by weight.

Figure 2-5 Cost of Control Using API Estimates – Pneumatic Pumps

2.6 Many Areas That Will Be Impacted By The CTG And Model Rule Are Low VOC Gas Areas

The oil and natural gas produced in the US varies considerably. This can range from very heavy, thick crude oil (a.k.a. black oil or dead oil) that has no associated natural gas, to light hydrocarbon liquids (a.k.a. condensate) that co-produce VOC-laden gas, to gas that is almost 100% methane with no associated liquids. Each type of formation may have some similarities, but still can have wide variation. Some tight sands behave like sand stone and can produce significant amounts of heavier hydrocarbons. Shale fields run the gamut from wells that produce nearly 100% methane to wells that produce significant quantities of hydrocarbons that are liquid at stock tank conditions. The definitions of the various types of reservoirs are very broad and the defining characteristics have little to do with the reservoir's potential to emit VOC or HAP.

As evidenced by the brief discussion above, areas that produce low VOC gases are likely to be adversely and unfairly impacted by high costs with little VOC emission reduction. However, this is not just a theoretical exercise, as there are numerous areas that will be impacted by EPA's RACT recommendation and model rule and the resulting SIPs where low-VOC gases are prevalent.

There are several active oil and natural gas production areas that are in the ozone transport region or ozone nonattainment areas (or in areas likely to be nonattainment under the new 70 ppbv ozone NAAQS) where the VOC content is very low. These include, but are not limited to the Marcellus, New Albany, Barnett, and Mancos areas. It is estimate that there are over 23,000

wells in these low-VOC areas.² While not all of these areas will be in moderate or above ozone nonattainment areas where RACT is required, States may choose to voluntarily implement these recommended RACT requirements to address the VOC from oil and natural gas operations.

In addition, coal bed methane (CBM) typically is produced at low pressures and contains very high percentage of methane (often as high as 97% by volume) and almost no hydrocarbons heavier than ethane. Coal has classically been thought of as a “cap rock”, not a reservoir rock. This means that the pore volume (i.e., porosity) is on the order of 0.25%. This very low porosity demonstrates that the only gases that can be stored in the coalbed must be of a size that allows them to be adsorbed to the surface of the coal. Coal has a high affinity to accept CO₂ onto its absorption sites, and a slightly smaller affinity for methane. Heavier hydrocarbons do not “fit” on the adsorption sites (the traces of heavier hydrocarbons that are sometimes reported in CBM fields have come from the very small pore volume, not desorption). Consequently, CBM fields tend to have zero or near zero VOC emissions. There are also several CBM areas that are in the transport region or potential ozone nonattainment areas including, but not limited to, the Black Water, Appalachian, and Uinta areas. It is estimated that there are over 10,000 CBM wells in these areas.³

Therefore, a large number of low-VOC sites could be impacted by the RACT rules resulting from this CTG. These sites will be subject to requirements that clearly have costs at a level that EPA has considered unreasonable in relation to the associated VOC emission reductions. Therefore, EPA must include VOC applicability thresholds in the RACT recommendations and model RACT rules to avoid these high cost impacts with very minimal environmental benefit.

2.7 There Is Precedent For VOC Applicability Thresholds In Ctgs And Federal Regulations

There are precedents in many NSPS and other federal regulations where EPA has recognized that the composition of the gas impacts the level of emissions, and thus has included applicability thresholds. This is particularly prevalent for regulations that focus on fugitive emissions, such as the 1983 CTG for fugitive monitoring in Gas Processing⁴ (which stated 1% VOC by weight; see section 16.2.8), and multiple NSPS subparts. For example, NSPS subparts VV and VVa only cover equipment “in VOC service,” which is defined as equipment that “contains or contacts a process fluid that is at least 10 percent VOC by weight.” In other words, equipment components that contact a process fluid with less than 10 weight percent VOC are exempt from the leak detection and repair requirements.

² Marcellus - <http://stateimpact.npr.org/pennsylvania/drilling/>

New Albany - <http://www.in.gov/dnr/dnroil/files/og-NASWellsByStatus1990to2013.pdf>

Barnett - http://www.tceq.state.tx.us/assets/public/implementation/barnett_shale/bs_images/bsOilGasWells.png

Mancos - https://www.env.nm.gov/aqb/4C/Documents/Mancosshale_May30_2012.pdf

³ Black Warrior - <http://www.gsa.state.al.us/gsa/cbm/Coalbed%20Methane%20Research.htm>

Appalachian - http://www.dcnr.state.pa.us/cs/groups/public/documents/document/dcnr_007916.pdf

Uinta - http://www.blm.gov/style/medialib/blm/ut/vernal_fo.Par.57849.File.dat/GCW%20Cums%20TSD%2003-22-12%20final.pdf

⁴ http://www3.epa.gov/ozonepollution/SIPToolkit/ctg_act/198312_voc_epa450_3-83-007_leaks_naturalgas_processing.pdf

2.8 Conclusion: EPA Must Include Applicability Thresholds Based On VOC Content In The Gas

The discussion above clearly proves the need for EPA to include applicability thresholds based on VOC content in the gas for the RACT recommendations and model rule for several fugitive emission sources where it is proven that the cost effectiveness levels are at unacceptable levels as VOC content decreases.

Specifically, API recommends that EPA exempt the following emission sources from RACT requirements in the CTG if the gas composition at the site exceeds an appropriate threshold. Using EPA's proposed cost estimates that threshold is 7.0 % VOC by weight or less:

- Pneumatic controllers at gas processing plants,
- LDAR at gas processing plants,
- Pneumatic piston pumps, and
- Fugitive emissions at natural gas well sites and gathering and boosting stations.

Considering API's more accurate cost estimates, requirements for fugitive VOC emissions at all well sites and pneumatic piston pumps are not cost effective even using EPA's representative composition. Further, the cost effectiveness for the requirements for pneumatic diaphragm pumps becomes reasonable at 15 % VOC by weight.

3.0 EPA SHOULD APPLY LOW PRODUCTION EXEMPTION TO ALL EMISSION SOURCES AND THIS EXEMPTION SHOULD APPLY WHENEVER THE AVERAGE PRODUCTION OF A WELL SITE FALLS BELOW THE 15 BOE/DAY LEVEL

In Section 9.1 of the CTG, EPA states: "For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrels of oil equivalent per well per day (15 boe/day), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved."

This exemption is specific to the fugitive emission requirements at well sites. However, the reasons stated by EPA are applicable to all emission sources at low-production well sites. Therefore EPA should universally apply this exemption and totally exempt all sources at well sites with average production of less than 15 boe/day from all requirements.

Furthermore, this exemption should apply throughout the life of the well site. In other words, whenever the average production of a well site falls below 15 barrel equivalents it should no longer be subject to any RACT requirements.

4.0 THE CTG DOCUMENT DOES NOT ADEQUATELY COVER ALL THE DATA REQUIRED BY THE CLEAN AIR ACT, WHICH INCLUDE RETROFIT COSTS, OPERATIONAL COSTS, ENERGY REQUIREMENTS, ENVIRONMENTAL IMPACTS, AND FUEL COSTS.

Clean Air Act Section 108(b)(1) outlines the information that EPA is required to provide to states and other air pollution agencies related to air pollution control techniques for criteria pollutants associated with NAAQS. Specifically, this paragraph states that EPA “shall include data relating to the cost of installation and operation, energy requirements, emission reduction benefits, and environmental impact of the emission control technology. Such information shall include such data as are available on available technology and alternative methods of prevention and control of air pollution. Such information shall also include data on alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions.” In this CTG, EPA failed to comply with this requirement. Not only did lead to insufficient information being provided for states, it led EPA to recommend RACT requirements (which are reflected in the model rule) that are not based on accurate information. Throughout these comments, API points out examples of the inadequacies in EPA's cost estimates.

4.1 The CTGS Must Take Into Consideration The Impacts And Costs Of Retrofitting Existing Sources

EPA is not taking into account the significant cost differences between applying a control in a new and existing operations. Applying BSER controls to existing source controls are more expensive (not RACT) for several reasons. As economically feasible is part of the definition of RACT, these costs must be considered.

- Existing controls may not be adequate for CTG compliance. There will be situations where the control device itself is not designed adequately or does not have the necessary uptime and efficiency, or is designed for testing and monitoring. Furthermore the existing control device may not have the monitoring systems required by the CTG. The control device may have been installed for state permitting or regulatory compliance, or maintaining emissions below a threshold, In these situations the existing control device and monitoring systems would need upgrade, potentially significant upgrade. Those costs must be considered by USEPA in their evaluation.
- There may be permitting implications if a flare is the chosen control device.
- New land may be required to add control devices to existing sites.
- Existing vapor recover units, compressors, and storage vessels may require early retirement.
- Existing controls may have remaining useful life and will require early retirement.

4.2 EPA Should Consider The Cost Of Disturbance Of Land To Install New Controls

One of the elements that EPA did not consider in estimating the impacts of these RACT requirements on existing sources is the cost of disturbance of land to install new controls. Industry standards and insurance typically require that combustion devices must be placed 50-150 feet from equipment containing hydrocarbon to avoid explosions from thermal radiation. Due to the spacing requirement for control devices, adding a control device may require additional surface disturbance beyond the existing pad location. There are numerous repercussions of additional land disturbance including:

- Additional land may have to be purchased. EPA has not included in the cost estimate for the control devices the cost of the additional land that would be required.

- Wetlands may be further impacted requiring additional wetland mitigation and/or a Corps 404 Permit under the Clean Water Act. EPA has not considered the additional cost for wetland mitigation and permitting.
- The additional land needed may encroach on endangered species habitat and may not be allowed to be developed or require additional mitigation. EPA has not considered the impacts of this situation.
- Federal land will potentially require NEPA analysis for the additional disturbance. EPA has not considered the great cost and effort of a NEPA analysis for additional disturbance on Federal land.
- National Historic Preservation Act review may be required for the additional disturbance. EPA has not considered the impact under the NHPA.

4.3 EPA Should Not Require The Same Controls As In The NSPS, Which Is For New Sources

On September 18, 2015, EPA proposed NSPS Subpart OOOOa, which covers all the same emission sources addressed in the draft CTG but for new sources. The Clean Air Act has requirements for evaluating the stringency of controls for the different programs.

Control Technique Guidelines define Reasonably Available Control Technologies (RACT) as the following:

- “RACT emissions limitations are the lowest emissions limitations that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.”⁵
- While EPA has not set a financial threshold for RACT, per a 2006 EPA memo⁶, generally the VOC cost threshold has been approximately \$2000 per ton in 1980 dollars (\$5,784.37 in 2015 dollars⁷).

New Source Performance Standards outline the Best System of Emissions Reduction (BSER)

- “For purposes of this section, if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. (CAA – U.S. Code Title 42 Chapter 85 Subchapter I Part A 7411 (h)(1).”

Despite this difference in statutory authority, in this package of rulemakings, EPA has determined in almost every case that the exact same controls are appropriate for new sources and existing

⁵ http://www3.epa.gov/ttn/atw/ctg_act.html

⁶ <http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf>

⁷ http://www.bls.gov/data/inflation_calculator.htm

sources in non-attainment areas. In other words, EPA determined that BSER and RACT are equal. In a few cases (alternative emission limitation for storage vessels, continuous monitoring provisions for storage vessels), the RACT requirements in the model rule in the appendix to the CTG are more stringent than the NSPS. EPA cannot propose the same requirements for BSER and RACT without an explanation. EPA must re-evaluate RACT based on the appropriate criteria and re-issue the draft CTG based on these appropriately conducted analyses.

5.0 EPA SHOULD REITERATE THAT EACH STATE IS ABLE TO ADOPT OTHER EXISTING REGULATIONS IN LIEU OF CTGS AS RACT.

EPA has defined RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility” (44 FR 53762; September 17, 1979). Since the cost effectiveness tabulations are based upon a nationwide average, economic feasibility⁸ may vary from state to state. Thus, while EPA considers CTGs to constitute “presumptive” RACT, states are not required to adopt the control measures specified in CTGS as RACT. CTGs may not meet the definition of RACT⁹ in terms of being reasonably available for a specific source or source category for a particular area.

Additionally a RACT analysis might conclude different control measures should include the application of a VOC threshold for the implementation within a particular area based upon the sources in that particular area.

According to 2006 Guidance from Harnett¹⁰, in response to a question regarding how to address requirements as part of the SIP where a State determination that sources subject to Federal rules meet RACT by compliance with those requirements:

To rely on federal rules to meet the RACT requirement, the State must incorporate these requirements into the SIP. For example, a State could incorporate by reference the Federal requirement or could submit a permit that includes this provision as a SIP revision.

The same guidance points out that “a State may rely on control obligations required by federally enforceable permits by submitting the relevant portions of these permits (i.e., the portions establishing the VOC and NOx obligations) as SIP revisions along with a demonstration that such controls are RACT.” And “a RACT analysis needs to be done for all CTG sources and all major non-CTG sources. While the CTGs and ACTs provide a starting point for such an analysis, RACT can change over time as new technology becomes available or the cost of existing technology adjusts. States are encouraged to use the latest information available in making RACT determinations, whether that information is in CTGs, ACTs, other guidance that is available or through information submitted during the public review process.”

⁸ 1994 guidance indicates that cost effectiveness should be within \$160 to \$1300 per ton.

⁹ Note that API does not agree with this presumption, as there is no basis under the law for the suggestion that EPA's recommendations carry any greater weight than individual state determinations.

¹⁰ <http://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf>

While a CTG is the starting point for a RACT analysis for a source category covered by a CTG, the analysis must still be conducted to identify “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” EPA should reiterate this obligation and that it is wholly acceptable that such an analysis may conclude that existing regulations satisfy the RACT obligations for a source category and the CTG need not be adopted as written.

An example of where this is especially true relates to monitoring, inspection and performance testing requirements. States typically have their own policies and procedures on these requirements. It is less burdensome for state agency personnel and the regulated community to use the state compliance assurance requirements in lieu of the EPA style requirements included in the model rule. If EPA includes compliance assurance requirements in the model rule, EPA should specifically state in the preamble that state may utilize their own compliance assurance provisions in lieu of those in the model rule.

6.0 API REQUESTS THAT THE CONTROL TECHNIQUE GUIDELINES FOR THE OIL AND NATURAL GAS INDUSTRY AND EPA'S SIP PLANNING GUIDANCE ENCOURAGE STATES NOT TO REQUIRE EMISSIONS OFFSETS FOR MINOR OIL AND NATURAL GAS EMISSIONS SOURCES.

States with marginal non-attainment areas and above are subject to the non-attainment new source review requirements including offsets for increases of emissions for new or modified major stationary sources. While the Clean Air Act only requires emissions offsets in the Non-attainment New Source Review (NNSR) program for major sources in non-attainment areas, some States additionally require offsets for minor sources (Wyoming – WYDEQ). Additionally, some State statutes do not distinguish between major sources and minor sources in their Prevention of Significant Deterioration (PSD) programs applicable to attainment areas with respect to the requirement that new or modified facility does “*not cause or contribute to an exceedance of a NAAQS.*” (e.g. Wyoming WAQSR Chapter 6, Section 2(c)(ii)), which can result in air quality offset requirements for minor sources. In rural areas of the US, where most oil and natural gas development occurs, there are limited opportunities to acquire emission or air quality offsets. In the event emissions offsets are required, new oil and natural gas production could be significantly restricted.

With Control Technique Guidelines and NSPS OOOO/OOOOa, the value of additional VOC offsets through beyond-the-requirements control of minor sources is even further diminished. Additionally, virtually no offset opportunities exist for oil and natural gas in rural areas. Thus, API requests that the CTGs and EPA's SIP planning guidance specifically encourage states not to require emissions or air quality offsets for minor oil and natural gas emissions sources.

7.0 STATES SHOULD BE ALLOWED TO DETERMINE WHAT CTGS SHOULD BE APPLIED

The precursors to ozone formation are both VOCs and NO_x. The net impact of ozone formation depends on the NO_x, VOCs, and meteorology for a particular location. As noted in EPA's

Integrated Science Assessment for Ozone^[1], “Duncan et. al 2010^[2] found that O₃ [ozone] formation over most of the U.S. became more sensitive to NO_x over most of the U.S. from 2005 to 2007 largely because of decreases in NO_x emissions.” Further control of VOC in many areas may result in no discernible ozone reduction. Moreover, control of emissions with combustion devices results in increases of NO_x. The ozone formation for most of the U.S. is NO_x limited; therefore, in most areas of the country adding more NO_x could result in increased ozone formation and implementing a CTG RACT rule would be counterproductive. Analysis for particular areas could find that there was no benefit to ozone reductions with application of CTGs, or in the worst case, such an analysis may find that the net result of controlling VOC emissions with combustion creates *more* ozone since it would add NO_x emissions. EPA should allow the states to determine whether incorporation of the CTGs into RACT SIPs is beneficial through analysis of the air quality for the particular area.

8.0 THE FINAL CTG SHOULD INCLUDE A FEDERAL FRAMEWORK FOR ENCOURAGING VOLUNTARY METHANE REDUCTIONS FROM EXISTING OIL AND NATURAL GAS SOURCES

The incentive to generate voluntary methane reductions from existing oil and natural gas sources will be significantly undercut if EPA adopts CTGs that apply to all existing oil and natural gas sources, including those highly-controlled sources that have voluntarily implemented “best management practices” (BMP) under the Methane Challenge Program. In particular, the adoption of CTGs applicable to the entire source category will trigger a requirement for states to establish RACT standards for all sources, including the BMP-controlled sources, which are located in ozone nonattainment areas and ozone transport areas classified as moderate or higher. The imposition having to change from the BMPs to the RACT requirements once they are finalized will deter many companies from trying to implement the BMPs. Furthermore, once the RACT requirements for the CTGs are included in a state’s regulations and State Implementation Plan (SIP), companies will be unable to get offset credits from reduction implemented under a BMP that they make legally and practically enforceable.¹¹

To correct this problem, EPA should establish in the final CTGs a federal framework that encourages, to the maximum extent permissible under the CAA, voluntary methane reductions from existing oil and natural gas sources. Such methane reductions are necessary to help ensure

^[1] US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R-10/076F.

^[2] Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NO_x and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223.
<http://dx.doi.org/10.1016/j.atmosenv.2010.03.010>

¹¹ The CAA establishes specific rules for the generation of offsets. One key requirement is that the emission reductions must not otherwise be required by some other CAA program or regulation. See Section 173 (c)(2) of the CAA (providing that “Emission reductions otherwise required by this chapter shall not be creditable as emissions reductions for purposes of any such offset requirement”). EPA has also established federal guidance providing that to the extent that the emission reductions are in fact required by CAA, those reductions are not “surplus” and consequently may not be used to generate offsets. See Emissions Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits, 51 Fed. Reg. 43,814, (December 4, 1986).

the achievement of the Administration's goal to cut methane emissions from the oil and natural gas sector by 40-45 percent from 2012 levels by 2025.

This important policy objective can easily be accomplished by narrowing the scope of the oil and natural gas sector subject to the CTGs as well as setting the control thresholds for sources such as storage vessels at a higher level than the NSPS OOOOa levels. Also the final CTGs should include language that excludes sources that have established legally and practically enforceable limits for already implemented BMPs under the Methane Challenge Program from implementing the CTG requirements. Sources that are controlled and following the BMPs for the Methane Challenge that have made them legally and practically enforceable could use the reductions as offsets since they are not under the CTGs. Allowing companies to be exempt from the CTGs that implement the BMPs and make them legally and practically enforceable to get offsets will encourage companies to make reductions earlier than when they would be required for newly designated ozone nonattainment areas under the 2015 ozone NAAQS. Final designations will be issued by October 26, 2017 and the RACT SIPs will be due by October 26, 2019 that would need to include the CTGs. Any reductions made after the designations years of 2013-2015 or 2014-2016 could still be used for Reasonable Further Progress demonstrations and used as offsets as long as they are done before the RACT regulations are put in place. If the CTG fails to provide a source category exclusion for those sources that have voluntarily implemented BMPs for reducing their methane and VOC emissions, the only option available to generate offsets will be for existing sources to achieve VOC reductions that exceed the RACT control levels specified in the CTGs. Under this "RACT-Plus" approach, sources could generate offsets for only a small increment of the total VOC reductions that the company could achieve by the implementation of BMPs under the Methane Challenge Program. This small increment would be those VOC reductions that are in excess of the VOC reduction levels mandated by the state in the VOC RACT standards applicable to affected oil and natural gas sources.

Only a small increment of the total VOC reductions achieved by companies under the Methane Challenge Program would be available to generate a correspondingly small amount of offsets once the CTGs are incorporated into the state regulations. This small amount of offsets may not be a sufficient incentive to encourage robust participation by many companies to achieve substantial methane emission reductions under the Methane Challenge Program above any VOC RACT standard. Furthermore, the states could impose stricter requirements for RACT in their regulations and RACT SIPs beyond the CTGs leaving no further reductions available. The window to do reductions that would still be creditable by making the BMPs legally and practically enforceable but before CTGs are incorporated in the regulations and the RACT SIPs will only be from 2017-2019 giving companies a very small window to acquire offsets.

9.0 THE CONTROL DEVICE TESTING AND MONITORING COMPLIANCE ASSURANCE REQUIREMENTS ARE NOT APPROPRIATE

9.1 Oil and Natural Gas Production Sites Are Unique From Traditional Stationary Sources

The sources that will be subject to RACT rules based on the recommendations in the CTG are unique from typical stationary sources in that they are small sites, located in remote areas, dispersed from each other (often requiring an hour or more travel time between regulated sites), and typically unmanned. These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. Because EPA has "force fit" the testing, monitoring, and other compliance assurance requirements designed for traditional stationary sources to the oil and natural gas industry, the proposed testing and monitoring requirements result in unnecessary

burden without a commensurate benefit. Sections 9.1.1 through 9.1.3 briefly describe some of the unique aspects of the oil and natural gas industry. Sections 9.2 and 9.3 provide specific examples of the inappropriateness of these requirements and provide recommendations that will ensure compliance and environmental benefit without creating unnecessary and costly burdens on the industry.

9.1.1 Oil and natural gas Production Operating Conditions Are Not Steady State

Oil and natural gas operations are unique due to the dependence on the naturally occurring underground nature of the resource being harvested. This section summarizes some of those unique characteristics and their impact on emission control devices (primarily combustion control devices).

Unlike other industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas is located thousands of feet below the surface and must flow in two or three phases to the surface. Ideally, this flow would occur at a relatively steady rate at a velocity fast enough to suspend small droplets of produced water and liquid hydrocarbons during the vertical ascent to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system. This may occur at times, but it is not typical.

As production declines and velocity in a vertical pipe decrease, the small droplets start to move slower than the gas combine into larger and larger droplets. These eventually form slugs of liquid that must be pushed up the pipe. The increasing back-pressure on the reservoir reduces in-flow, production, and hence velocity. As backpressure on the reservoir increases and the velocity continues to decrease, the liquid column in the wellbore can stop the gas flow until the gas pressure below the slug increases sufficiently to push the liquid to the surface. The management of these wellbore liquids is a major concern throughout the life of a well that mandates changes in both down hole and surface equipment. The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible.

9.1.2 Production Separator Operation

The purpose of the two or three-phase production separator is to separate the two or three-phase flow from the well to make sure that only natural gas goes to the gathering system and only liquid hydrocarbons and produced water are sent to their respective storage vessels. Separators are sized to give sufficient "residence time" to allow the separation of phases to take place. Since the actual mix of gas, oil (or condensate), and produced water varies randomly with time, it is impossible to predict when or how often a given control-action will occur.

The flow into the separator is made up of the fluids that the reservoir produces at any given moment, as modified by the transport of those fluids to the surface. The liquid levels in the separator are maintained by valves (often called dump valves) on the separator outlets to the oil/condensate storage vessel and the produced water storage vessel (although liquid collection systems are sometimes used in lieu of a storage vessel). The dump valves are sized to handle the highest flow rate of liquid that the separator can be expected to receive. Because of the highly

variable flow conditions, separators normally provide flow to storage vessels in short spurts, typically lasting only seconds, to maintain the required liquid levels and dump cycles may be separated by many minutes, hours, or even days.

9.1.3 Closed Vent System Flow Rate

Gas flow from the storage vessel into the closed vent system (CVS) predominantly results from flashing vapors (resulting from the spurts of liquids from the separator) and dwarfs the working and standing/breathing emissions typical from storage vessels (that occur between spurts). However, the CVS and control device must be sized sufficiently to handle the peak vapor volumes expected. Measuring the flow in CVS causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology (see “Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas”, Attachment A). Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds, and be able to go back to zero just as quickly. The hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients. Currently for minerals accounting purposes the Federal government and states do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology.

9.2 The Proposed Testing, Monitoring, And Other Compliance Assurance Requirements Are Inappropriate For The Oil and natural gas Industry

9.2.1 The NESHAP-Level Approach For Compliance Assurance Is Inappropriate And Unrealistic For Oil and natural gas Production Sites

For the most part, EPA has copied the full MACT control device and compliance assurance requirements in NESHAP HH (40 CFR 63, Subpart HH) for the CTG model rule, rather than craft cost-effective requirements tailored to address the unique situations related to RACT for oil and natural gas operations. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for the RACT recommendations. Furthermore, these RACT regulations will apply to dispersed that do not have electricity, may not have automation and may have limited space for existing automation to accept additional inputs into their programmable logic controller (PLC) and remote transmitting unit (RTU). Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH major sources, it is not appropriate to arbitrarily invoke compliance assurance requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for RACT guidelines for the control of volatile organic compounds (VOCs).

Examples of the inappropriateness of invoking MACT compliance assurance requirements for RACT guidelines include but are not limited to:

- E.2(a) of the model rule requires Continuous Parameter Monitoring System (CPMS) for control devices. EPA did not include the cost for installing, maintaining, and operating a CPMS in any of the impact assessments for this rulemaking. Most affected facilities in the production segment of the industry will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable

logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work cannot be performed by lease operators during normal inspection visits.

- E.2(f)(1) of the model rule requires the operator to establish minimum and/or maximum values for the operation parameter and operate the control device within the range. As explained in section 9.3.4, this requirement is impractical to meet for either manufacturer certified combustors or combustion controls where the performance test is performed in the field, but for different reasons. This requirement is the same as the NESHAP HH requirement located in §63.773(d)(5)(i)(a) & (c).
- Similar to above, E.2.(d)(1)(iii) of the model rule requires that a flare pilot be assured by a heat detection sensor and continuous controller. Section E.2(a) of the model rule makes this appear to be a CPMS requiring all of the assurance provisions of (c), (f) and (g). This requirement is essentially identical to the one in §63.773(d)(3)(i)(C) with the CPMS general provisions located §63.773(d)(1) requiring to meet (4), (6), & (7). Requiring a pilot monitoring device to meet the requirements for a CPMS is extremely burdensome for any rule but is unprecedented for RACT regulations.
- Compliance Demonstrations (E) and Test Methods (F). EPA reference methods that determine percent reduction on a mass basis, as is specified in Subpart HH major source control requirements where the CTG model rule does not specify percent reduction of a pollutant on a mass basis. This causes the measurement of volume that is not practical or in many cases possible with the types of operations and fluid flows typical for these facilities.

9.2.2 Compliance Assurance Requirements Are Unnecessarily Complex

The use of extensive cross referencing both between sections concerning control devices (i.e., E.1 for initial compliance requirements, F for performance testing, and E.2 for continuous monitoring requirements) and various test methodologies renders the requirements confusing and nearly impossible to follow. These segmented requirements unnecessarily add to the compliance burden, and likely to lead to errors and misunderstanding. Companies that operate stationary sources subject to EPA's NSPS and NESHAP regulations may have personnel whose sole job is to understand EPA's complex requirements. However, many companies regulated by these RACT rules are primarily small businesses that do not have this luxury. API members along with the consultants they have hired have had difficulty in interpreting the requirements for control devices as proposed. There is still not agreement of interpretation within API with many of the provisions.

9.2.3 The Compliance Assurance Requirements For Centrifugal Compressors Are Not Justified

During discussions with EPA, API was told that the control device monitoring and testing requirements of the 2012 rule were retained since few centrifugal compressors were expected to require control and that most of these affected sources would be located at more developed facilities, such as Natural Gas Processing Plants. While this statement may sufficiently explain the retention of some of the monitoring provisions, it does not address the practical considerations in complying with the performance test provisions and the identifying parameter ranges required for the continuous monitoring. Although there are few centrifugal compressors that require

control, almost all of the control devices they are connected to also fed with gases from other sources, such as storage vessels, that bring in the impracticality of flow measurement discussed in Section 9.1.3.

9.2.4 The Proposed Compliance Assurance Requirements For Pneumatic Pumps Have Numerous Problems

There are many issues with the proposed compliance assurance provisions for pneumatic pumps. Following are two major issues associated with the compliance assurance requirements. These are discussed at length in Section 15.0

Compliance Assurance Requirements of an Existing CVS/Control Device Should Not Change

EPA determined that the benefit of controlling the discharge of a pneumatic pump was insufficient to justify the installation of a control device, thus the requirement to only connect new pneumatic pumps to existing CVS/control device. Further, EPA only considered the cost of piping the pump discharge to the CVS but did not include costs for additional compliance assurance (see Section 15.3). Most control devices are expected to be installed due to state minor source NSR permits. These permits have their own compliance assurance requirements which are significantly different those in the CTG model rule, resulting in significant additional cost. These additional costs have not been included in EPA's cost analysis, cannot be justified with the low emission benefits achieved, and add no additional environmental benefit. Thus, API recommends that EPA should not require additional compliance assurance requirements in the CTG model rule for a CVS or control device when a pneumatic pump is connected to it (see Section 15.0).

Clarification is Needed When a Pneumatic Pump Must be Connected to a CVS/Control Device

There is significant uncertainty on when a pneumatic pump must be connected to a control device. Control device is an undefined term and defining it is a necessary first step to resolve this issue (see Sections 10.0 and 15.4.5). Another great source of uncertainty is when a boiler or process heater is considered a control device and when it is part of a process (see Section 10.0). API believes that pneumatic pumps should not be required to be routed to a boiler or heater.

Further, the control device and the pneumatic pump may be owned/operated by two different companies (i.e. chemical injection for gathering system corrosion control at a well site). In this case, even though a control device is at the location, it is not available to the owner/operator of the pneumatic pump (see Section 15.4.6). Finally, instances occur where it is not technically feasible to connect the pneumatic pump to the control device (see 15.3.3).

9.3 Compliance Assurance Requirements For Combustion Control Devices

9.3.1 The Proposed Compliance Assurance Requirements May Discourage The Use Of Enclosed Combustors

The design of enclosed combustors intrinsically yields higher destruction efficiencies than flares because of the heater style of burner and protection from cross wind. The enclosure also creates an induced draft of air that aids complete combustion of heavier (higher molecular weight) hydrocarbon streams. Additionally, the enclosure isolates the flame from sight that may cause concern to some members of the public. These benefits sometimes encourage industry to install the high cost internal (i.e., "enclosed") combustor instead of the commonly used open flame flare. Enclosed combustors do have the ability to be performance tested where the open nature of flares do not. It is ironic that EPA is requiring substantially more burdensome monitoring and performance testing requirements for enclosed combustors in the proposed rule, even though

these combustors have greater environmental benefit than flares. It is counterproductive for the environment to disadvantage enclosed combustors with compliance assurance requirements, just because they are technically feasible. EPA should encourage the use of enclosed combustors by using the same visual inspection requirements as with flares for opacity.

9.3.2 The Continuous Parameter Monitoring System (CPMS) Provisions Are Inappropriate

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. For the reasons stated below, EPA has not justified these requirements and must not include them in the final CTG model rule.

First, these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS.

Second, EPA did not justify the significant additional cost of this continuous monitoring. In fact, EPA did not include costs of monitoring equipment in their capital cost estimates, nor did they include any annual costs associated with the maintenance of this system or for the collection and maintenance of this monitoring data.

9.3.3 The Determination Of CPMS Range Determinations In Field Performance Test Is Technically Impractical

Section E.2(f)(1) of the model rule requires that for any parameter that requires CPMS monitoring, the operator must determine the minimum or maximum value of the parameter that continuously achieves the performance requirements in E.1(a). E.2(f)(1)(i) requires a performance test performed by the operator to determine the minimum or the maximum operating parameter based values measured during the performance test. However, the operator has limited ability to adjust the conditions of the process to test the control device. The performance test must be run at the conditions available when the test is scheduled. The operator is unable to vary the operating conditions to determine the limit of the operating parameter as a manufacturer does when conducting a shop test on an enclosed combustor. Section E.2(f)(1)(i) cannot practically be complied with, because the performance test cannot be completed at the full range of conditions for which the control device will be operated. Furthermore, this goes far beyond what EPA requires for testing control devices for NESHAP HH for area sources that apply to nearly all oil and natural gas production sites and approaches the NESHAP HH requirements for major sources like natural gas processing facilities. For a RACT rule at a remote, unmanned site, it is more reasonable to test the device during the current operating conditions.

9.3.4 It Is Not Technically Feasible To Meet The CPMS Flow Measurement Requirements For Manufacturer Certified Combustion Control Devices

Paragraph E.2(f)(1)(iii) requires that for manufacturer certified enclosed combustors, an operator must install CPMS measurement on the inlet flow to assure that the flow is not greater than the maximum or less than the minimum that the manufacture specifies. As explained in section 9.1.3, the measurement of flow from storage vessels is very difficult, even when only the normal emissions must be measured. With both the minimum and maximum range to be measured, it is

doubtful if a single instrument can measure both values. The pump flow as well is intermittent low pressure, low velocity/flow and difficult to measure as discussed in Section 15.0.

9.4 Compliance Options For Combustion Control Devices

Section E.1(a)(1) specifies four compliance options that can be used to assure compliance with the combustion control device requirements. These options include (1) percent reduction of the pollutant, (2) limiting the concentration in the exhaust, (3) maintaining a minimum combustion zone temperature, and (4) inject the stream into the flames zone of a boiler or process heater. Comments are provided below on options 1 and 2. As explained in Section 10.0 below, option 4 is a direct conflict with the definition of "route to a process", and therefore, API recommends that EPA remove E.1(a)(1)(iv) and (d)(4)(iv).

9.4.1 Percent Reduction Of Pollutant Should Be Based On Volume Not Mass And Should Not Require Measurement of Flow to the Control

The standards for centrifugal compressors, pneumatic pumps, and storage vessels each require a percent reduction.

- For centrifugal compressors, C.2(a) requires that VOC emissions be reduced by 95.0 percent or greater
- For pneumatic pumps located between the wellhead and point of custody transfer, H.2(b)(1) requires that natural gas emissions by 95.0 percent, and
- For storage vessels, A.2(a) requires that VOC emissions be reduced by 95.0 percent

Note that in none of these standards specify the basis for the 95.0 percent reduction. However the initial compliance demonstration requirements in E.1 add the requirement that this percent reduction in emissions be determined on a mass basis. The associated performance test requirements for calculating percent reduction by weight of pollutants requires the measurement of flow to the control device. These requirements were predominantly adopted from the major source NESHAP requirements in Subpart HH that specify control requirements of 95 percent reduction by weight. While mass reduction requirements may be appropriate and specified by Subpart HH, they are burdensome and impractical for RACT requirements for small, remote, dispersed and unmanned production facilities.

Section 9.1.3 above describes the many difficulties encountered when attempting to measure the flow of vapors to a control device at oil and natural gas production sites. EPA has not explained the reason for prescribing the reduction of pollutants to be determined by weight in the compliance demonstration and performance testing requirements when a mass destruction was not specified as part of the control requirements. Conditions of intermittent high/low flow conditions, variable and turbulent flow, and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API

requests EPA to determine percent of TOC reduction through a carbon balance methodology similar to that described in EPA's Flare Efficiency Study Report.¹²

The requirement in E.1(a)(1)(i), E.1(d)(1), and E.1(d)(2) should be modified to require reduction of TOC emissions by 95% on a volumetric concentration basis using a "carbon balance" methodology for analysis of the exhaust stack effluent from an "enclosed combustion device" being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO₂ and O₂, and 10 for CO should be specified for testing of the stack effluent gas. The CO₂ measured using Method 3A should be adjusted downward by the latest published atmospheric CO₂ concentration, as reported from the Mauna Loa monitoring site by NOAA's Earth System Research Laboratory, multiplied by the ratio of O₂ measured in the stack effluent as compared to the ambient O₂ content of 20.8 volume %. (3A measured CO₂ (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O₂ (ppmv)/208,000 (ppmv) ambient O₂ concentration)).

The percent pollutant reduction or destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(\text{CO}_{2c} + \text{CO}) / (\text{CO}_{2c} + \text{CO} + (3 * \text{TOC}))$$

Where:

CO_{2c} = CO₂ ppmv concentration measured in the stack via method 3A minus the ambient CO₂ ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following table shows this calculation and outcome for an assumed stack effluent composition:

Table 9-1 Assumed Stack Effluent Composition

Outlet CO ₂	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O ₂	150,000	
Ambient O ₂	208,000	
Ambient CO ₂	388	

¹² . Technical Report "EPA-600/2-83-052" "FLARE EFFICIENCY STUDY" by Marc McDaniel, July 1983 (see http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf).

Outlet CO _{2c} from combustion	29,720	Outlet CO ₂ - ((Ambient CO ₂ X (Outlet O ₂ /Ambient O ₂))
Destruction Efficiency	99.70%	(CO _{2c} + CO)/(CO _{2c} + CO + (3*TOC))

9.5 EPA Must Revise The Provisions Related To Flares Subject To §60.18

9.5.1 There Are Technical Challenges In Meeting The §60.18 For Flares In Oil and natural gas Production And Gas Processing That Must Be Addressed

Flares are an attractive control device choice for the oil and natural gas industry due to their simplicity, reliability, lower maintenance requirements, and effectiveness in reducing organic compound emissions. The requirements in §60.18 of the 40 CFR part 60 General Provisions were developed by EPA to generally apply to flares. However, these requirements were developed and refined based on industrial flares primarily used at large petroleum refineries and petrochemical plants. As discussed above in section 9.1, there are unique aspects of the oil and natural gas industry that require accommodations in the control device requirements. The following sections suggest changes related to the application of the §60.18 provisions to Subpart OOOO and OOOOa affected facilities that will allow the compliant use of flares in the oil and natural gas industry without compromising their effectiveness in reducing VOC and methane emissions.

9.5.2 The Use Of Electronic Ignition Systems Should Be Allowed

§60.18(c)(2) requires that flares shall be operated with a flame present at all times, as determined by monitoring using a thermocouple or any other equivalent device to detect the presence of a flame.

API continues to believe that an option to use electronic ignition systems should be allowed for the oil and natural gas sector. Since oil and natural gas operations are not always steady state, flares with continuously lit pilots (24/7) can unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emissions stream being burned. An attractive and effective alternative is to allow the use of electronic ignition systems that ensure a flame is present whenever emissions are being routed to the flare.

In addition, many oil and natural gas production sites are remote and unmanned. In these situations, an electronic ignition system has proven to be a more reliable means of ensuring there is always a flame when emissions are routed to the flare than attempting to maintain a continuous pilot.

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903.¹³ Presumably this was published because EPA approves of the design, recognizes its benefits and wanted to promote its use in industry. EPA should not forfeit the benefits of this control technology enhancement by disallowing its use. As an established and

¹³ <http://www3.epa.gov/gasstar/documents/installelectronicflareignitiondevices.pdf>

preferred technology by EPA in the Natural Gas STAR program, operators should not have to petition EPA for approval.

API recognizes the need to ensure that the electronic ignition system is working and that a flame is present at all times when emissions are being routed to the flare. API believes that the existing requirements in §60.18(f)(2) already provides an appropriate requirement: Paragraph (e) states that “Flares used to comply with provisions of this Subpart shall be operated at all times when emissions may be vented to them” and (f)(2) states “The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.” With the simple amendments to F(a)(1) and E.2(d)(1)(iii) shown below, EPA can allow the use of auto-ignition devices while also ensuring compliance.

Specific recommendations for these amendments are provided in section 9.5.5.

9.5.3 Testing Should Not Be Required To Demonstrate Compliance With §60.18(f)(4)

Paragraph 60.18(f)(4) requires that the volumetric flow rate be “*determined by Reference Methods 2, 2A, 2C, or 2D as appropriate*”. As a result, a test will be required for every flare used to comply with the CTG model rule. As discussed in section 9.1, the measurement of flow is impractical and potentially impossible at oil and natural gas production sites. In addition, even if these technical challenges were ignored, EPA’s estimate of impacts did not include significant costs that would be incurred by the industry.

While not specifically referenced in this paragraph, the provisions in §60.8(c) require that performance tests be conducted on conditions that reflect “*representative performance of the affected facility*.” During representative conditions, the exit velocities of the flare at oil and natural gas sites will never approach 400 feet per second. This can be easily demonstrated through the use of engineering calculations rather than testing or direct measurements. Specific changes must be made to F(a) to correct this situation. The recommendations for these amendments are provided in section 9.5.5

The technical challenges related to volumetric flow rate are not unique to storage vessels in the production segment. At many gas processing plants, pressure release devices are often routed to flares along with the emissions from other equipment. While there are typically no emissions from these pressure release devices, they can develop leaks. Under subparts OOOO and OOOOa, these pressure relief devices are subject to §60.482-4a(a) of NSPS subpart VVa. Since these pressure release devices are routed to a “closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device”, they are exempt from the LDAR requirements in §60.482-4a(a) and (b), but are subject to the closed vent system and control device requirements of §60.482-10a. Paragraph §60.482-10a(d) requires flares to comply with §60.18. The leaks that would occur from these pressure release devices would be very low, meaning that the difficulties in measuring the flow to these flares results in costly test programs that are entirely unnecessary given the extremely low flow rates. Therefore, API also recommends that the volumetric flow rate for these flares also be allowed to be determined using engineering calculations. API suggests that paragraphs be added to G.3 to address this technical infeasibility situation. These recommendations for these amendments are provided in section 9.5.5.

9.5.4 Sonic And Other Flares Operated During Maintenance, Startup, Shutdown, And Malfunction Situations Should Not Be Required To Comply With The Exit Velocity Requirements In §60.18(c)(4)

In EPA's September 18, 2015 Federal Register Notice (80 FR 56646), EPA specifically requested comment on the use of pressure-assisted flares in the oil and natural gas industry.

As EPA notes, pressure-assisted, or sonic, flares are designed to exceed §60.18's maximum exit velocity of 400 feet per second. As a result, they do not meet §60.18. Some facilities with potential large volume flows may utilize sonic flares, such as those included at onshore natural gas processing facilities, to control emissions in times of emergency, upsets, or maintenance. Sonic flares offer advantages over traditional low-pressure flares in some applications. For example, some designs allow smokeless operation over the entire operating range without any assist medium. This is a clear benefit for remote areas. Additionally, with no assist medium, energy usage and its related emissions are minimized and there remains no potential for steam/air over-assist. Some designs also offer less low frequency noise and less flame visibility in low profile designs. Sonic flares operate with destruction efficiencies that are at least as equivalent to, and generally greater, than low pressure flares.

Pressure-assisted (sonic) flares are not designed for continuous use, but instead operate in emergency, upset or maintenance situations where high volumes and pressures are sent to the flare. In some scenarios, pressure relief valves subject to LDAR monitoring are routed to sonic flares for the purpose of emergencies or upsets. Maintenance events are also routed to these flares in some cases.

However, a conflict with the velocity limits in §60.18(c)(3) is not limited to the case of pressure-assisted flares. Velocity limits for commonly used low-pressure flares (ground or elevated steam-assisted, air-assisted or unassisted flares) are achievable under representative day-to-day conditions. However, velocity limits for even low-pressure flares can be exceeded under conditions that approach the hydraulic capacity of flares. General application of §60.18(b) to a Subpart without the inclusion of §60.11 or an alternative exemption for periods of emergency, upset or maintenance is problematic.

Flares designed under §60.18(b) may exceed velocity limits during periods of emergency, upset or maintenance. In order to remain in compliance with the velocity limits, flare operators would need to install additional flare capacity for SSM events either by replacing an existing flare or adding additional flares. Therefore, the exemption from the §60.18 maximum velocity requirements should not be limited to pressure-assisted flares, but rather to all flares during periods of emergency, upset, or maintenance. As discussed in section 9.5.6 below, there is substantial evidence that indicates that the performance of flares will be maintained at these higher velocities.

Therefore, in order to allow the use of sonic flares and traditional flares designed under §60.18(b) for the oil and natural gas industry, EPA should exempt flares from the maximum velocity requirements in §60.18(c)(4).

Revisions are needed to F(a) and to G to allow the use of flares in these situations. The recommendations for these amendments are provided in section 9.5.5.

9.5.5 Recommended Model Rule Changes To Address Issues With Flare Requirements

Following are the recommended rule changes related to the issues discussed above that are related to the requirement that flares used for compliance with the CTG model rule comply with the requirements of §60.18.

G.3

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

E.1

(d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (45) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and F(e).

* * * * *

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

* * * * *

(5) You must design and operate a flare in accordance with the requirements of section F.

F(a)(1)

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

E,2(d)(1)

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in E.1(d)(3).

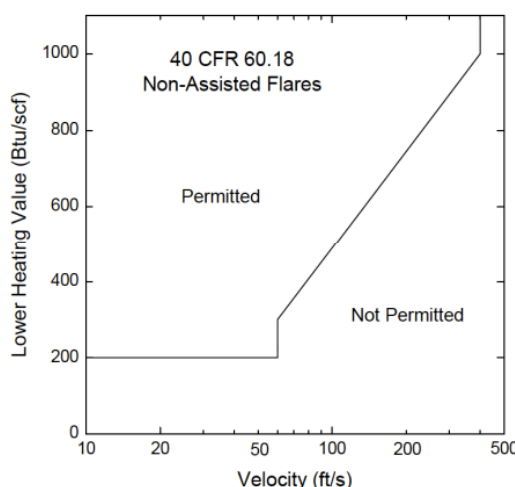
9.5.6 Velocity Limits in §60.18(c)(3) Are Unnecessary To Ensure High Destruction Efficiency in Flares

There is substantial evidence that flares operating with higher exit velocities are effective in reducing emissions. Following is a discussion of this evidence.¹⁴

Origins of Existing Flare Velocity Limits

The velocity limits in 40 CFR 60.18 were originally promulgated on January 21, 1986 and are graphically depicted below. The figure shows flame exit velocities in feet-per-second (fps) along the x-axis and lower heating value of the waste gas in Btu per standard cubic feet (scf) along the y-axis. A minimum heat content is required of 200 Btu/scf for unassisted flares or 300 Btu/scf for assisted flares up to 60 fps, where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps is reached.

Figure 9-1 Current EPA Flare Velocity Limits



This relationship was developed following a series of EPA sponsored tests conducted in the 1980's that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel¹⁵ test and the 1984 Pohl¹⁶ test. The focus of the 1985 Pohl¹⁷ and 1986 Pohl¹⁸ studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 feet per second (fps) have been included in this analysis.

The 1986 limits appear to originate with only four data points from these tests – the average value at the upper limits of each study. The 60 fps, 300 Btu/scf limit for steam-assisted flares was set

¹⁴ Adapted from "A Review of Flare Velocity Limits in 40 CFR 60.18 and 63.11." Prepared for American Petroleum Institute October 26, 2014 by Scott Evans.

¹⁵ McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983

¹⁶ Pohl, J., et. Al.; "Evaluation of the Efficiency of Industrial Flares: Test Results," EPA-600/2-84-095

¹⁷ Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Composition," EPA-600/2-85-106, September 1986

¹⁸ Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: H₂S Gas Mixtures and Pilot Assisted Flares," EPA-600/2-86-080; September 1986

Figure 9-3. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHVVG) is less than 270 Btu/scf, green dots indicate test runs with NHVVG between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

Scatter plot showing CE (%) on the y-axis (70 to 100) versus Velocity (ft/sec) on the x-axis (0 to 100). Data points are categorized by NHV status: <270 (red), 270-500 (green), and >500 (blue). Two specific tests are highlighted with red circles and arrows:

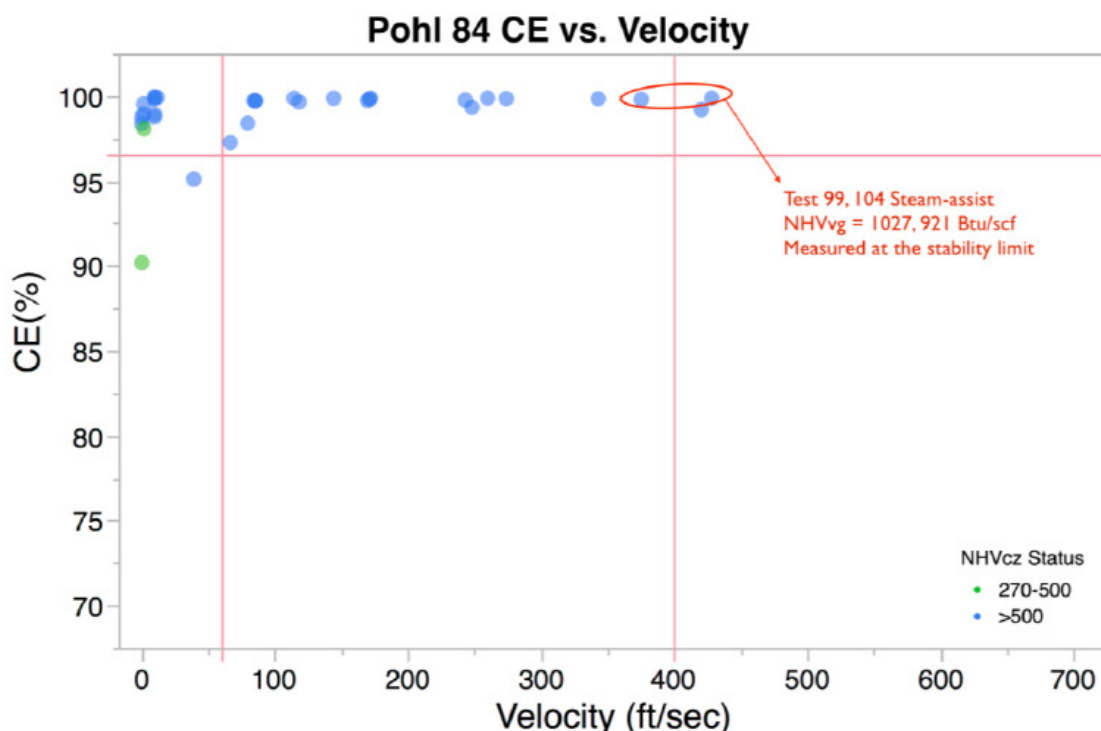
- Test 59 Unassisted: $NHV_{vg} = 205$ Btu/scf (at approximately 45 ft/sec, 99% CE)
- Test 57 - Steam-assisted: $NHV_{vg} = 298$ Btu/scf, $NHV_{cz} = 256$ Btu/scf (at approximately 62 ft/sec, 100% CE)

A horizontal red line is drawn at CE ≈ 96.5%, and a vertical red line is drawn at Velocity = 60 ft/sec.

McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.¹⁶ That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in

Figure 9-3. The data are binned by heat content, where green dots indicate test runs with NHVCZ between 270 and 500 Btu/scf and blue indicate test runs with NHVCZ greater than 500 Btu/scf.

Figure 9-3 A Comparison of Combustion Efficiency vs Velocity for Pohl 1984

Similarly to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

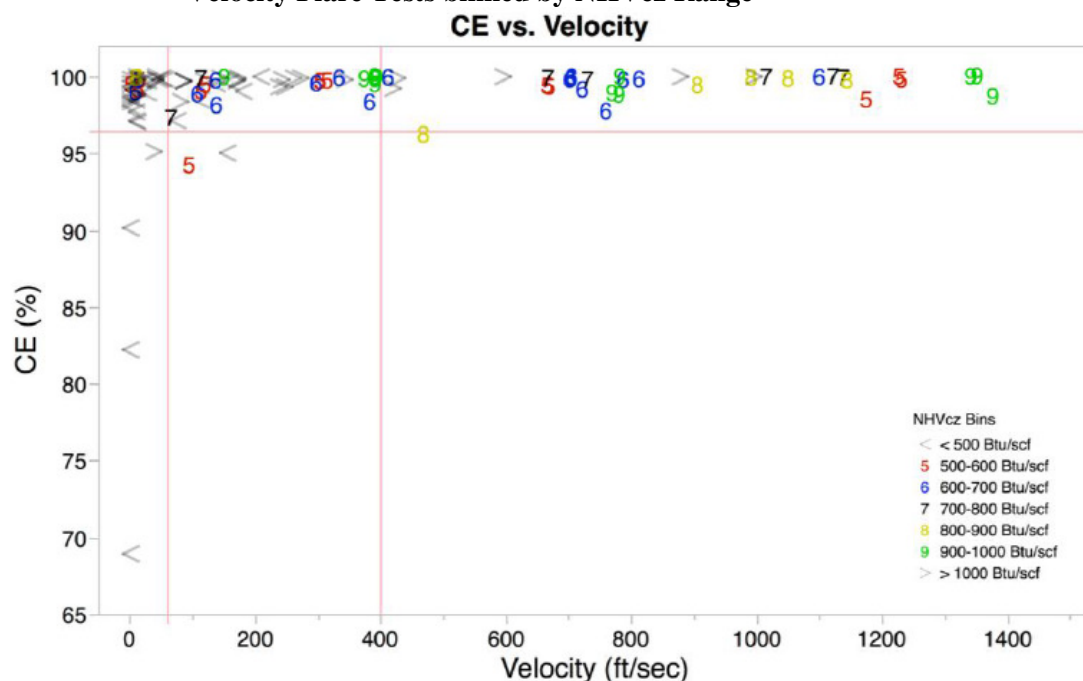
High Velocity Flare Test Data

Figure 9-4 shows all data from publically available high velocity flare tests as of October 2014. Some low velocity data are also included to the extent that they were measured during a test series including high velocity data. Data includes the 1980's flare studies referenced above as well as more recent studies (Marathon Garyville¹⁹ and Dow²⁰). This data is similarly displayed based upon combustion efficiency (CE) as a function of exit velocity in fps. The data is binned by combustion zone net heating value (NHVCZ) in groups of 500 Btu/scf. Only data with NHVcz > 270 are included.

¹⁹ Clean Air Engineering, "Performance Test of Steam-Assisted and Pressure-Assisted Ground Flare Burners with Passive FTIR – Garyville," March 21, 2013

²⁰ Varner, V., Kodesh, Z.; "Emission Testing of Pressure Assisted Flare Burners," Presented at the American Flame Research Committee 2014 Industrial Combustion Symposium, September 2014

Figure 9-4 A Comparison of Combustion Efficiency vs Velocity for All Publically Available High Velocity Flare Tests binned by NHVcz Range



Almost all of the low velocity data that also have low CE have NHVcz values less than 500 Btu/scf. Additionally, virtually all of the test runs with velocity greater than the current limit of 400 fps, were conducted at NHVcz values less than the current 1,000 Btu/scf limit. This graph clearly shows that high combustion efficiency above the current limits is not only possible, but that it is assured based upon available test data.

Flame Stability

The claim is often made that the reason velocity limits are necessary is to ensure “flame stability.” However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

The term "flame stability" simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out. [Pohl 84, p2-3]

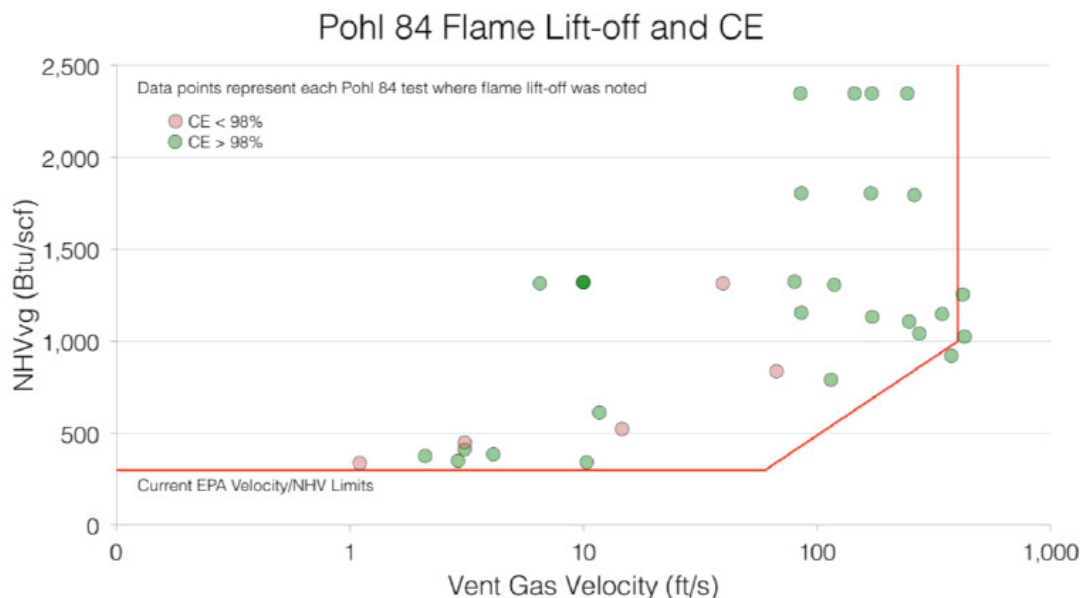
Others²¹ have defined flame stability in terms of “lift-off”, a conditions that occurs when the base of the flame detaches from the flare tip.

While there is no doubt that Pohl’s definition results in unacceptable flare performance, there is little evidence that flame lift-off has any correlation either positive or negative to combustion

²¹ Shore, D., “Improving Flare Design: A Transition From Art-Form to Engineering Science,” Presented at AFRC-JFRC October, 2007.

efficiency. Figure 5 shows every data point from Pohl 84 where flame lift-off was noted in the report.

Figure 9-5 A Comparison of Flame Lift-Off and Combustion Efficiency from Pohl 84



27 of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 9-5 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl's definition... a high velocity flame is stable until it goes out.

There is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the "snuff point." Both the Pohl 84 data and the Marathon Garyville data were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

Conclusion

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This paper reviewed data from the data sets used to establish those federal regulatory velocity limits as well as recent high velocity flare test results.

All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion efficiency (>96.5%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.

The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive.

9.6 While EPA Has Been Testing Various Manufacturer Devices, The Process Has Been Slow

The CTG model rule allows for the use of combustion devices that are tested by the manufacturer which eliminates the need for source testing at the site. This has been allowed under NSPS Subpart OOOO (40 CFR 60, Subpart OOOO) and MACT HH and HHH (40 CFR 63, Subparts HH and HHH), for several years. EPA maintains a list of approved Combustion Control Devices²² on their website. EPA has also stated that the current “approved list” will be adopted for OOOOa. API requests confirmation of this in the response to comments to reflect EPA’s intent.

However, there are several issues with the approval process. First, more than half of the devices listed on the website are characterized as “under review”, and they have maintained this status for a long period of time (one or more years). According to one manufacturer, the approval process should be less than a month. The CTG will result in the need for many more combustion devices to control existing sources, which increases the need to shorten the approval process. Closer inspection revealed that incomplete test reports may be a possible cause for achieving “under review” status, and therefore it may not be a fault of EPA’s process. However, EPA needs to investigate the cause for these long delays in this approval process and correct them.

Second, manufacturers report that relief from propene testing would decrease the testing costs considerably. The requirement for propene testing for combustion devices that will be used at oil and natural gas production facilities seems illogical as there are insignificant amounts of double bond hydrocarbon compounds in natural gas. API requests that F(d)(2) be modified as follows to allow the use of propane to expedite the approval process.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

10.0 EPA MUST ELIMINATE THE CONFUSION AND CONFLICT ASSOCIATED WITH “CONTROL DEVICE” AND “ROUTED TO A PROCESS”

It is clear from the model rule control requirements for centrifugal compressors at C.2(b), pneumatic pumps at H.2(b)(4), and storage vessels at A.2(b)(1) that “route to a process” was intended as an alternative to a control device. For example:

A.2(b)(1): Except as required by paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of Section D.1(a), that is connected through a closed vent system that meets the requirements of section D.1(b), and routed to a control device that meets the conditions specified in paragraph (b)(3)(i) and (ii) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

²² <http://www3.epa.gov/airquality/oilandgas/pdfs/mantesteddevices.pdf>

However, the definitions and provisions related to “control device” and “routed to a process” are inconsistent and confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters. The following sections highlight these issues and suggest a recommendation that will eliminate the confusion and conflicts without any reduction in the effectiveness of the rule.

10.1 Definition Of “Routed To A Process” Should Be Clarified

The CTG model rule includes the following definition:

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold.

The use of “routed to a process” is clear as used in connection to a VRU, as these emissions are recycled and incorporated into a product.

This definition also unmistakably applies to situations where the emissions are combusted in a boiler or process heater. There are three different ways in which hydrocarbon vapors can be fed into a boiler or process heater for destruction – 1) vapors routed to the flame zone, 2) vapors routed to the fuel system as a primary fuel, and 3) vapors routed to the combustion air supply as a secondary fuel. For all three of these methods of introducing hydrocarbon emissions into a boiler or process heater the emissions are clearly “consumed in the same manner as the material that fulfills the same function in the process” Further, the emissions are “transformed by chemical reaction into materials that are not regulated materials”. However, the CTG model rule is not as clear how this definition applies for boilers and process heaters. EPA must clarify this linkage between “routed to a process” and boilers and process heaters throughout the model rule.

Despite the fact that EPA defined routed to a process/route to a process in a manner that would include all situations when emissions are routed to a boiler or process heater, there are instances throughout the model rule where EPA appears to consider boilers and process heaters as control devices. For example, in E.1(a)(1), EPA includes boilers and process heaters in a parenthetical describing a combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater). Similarly, this same parenthetical description of enclosed combustion device in in E.1(d)(1). Further, in the list of “control devices” exempted from performance testing in F(a), there are several specific boiler and process heater examples that are exempted.

One of these exemptions, specifically F(a)(3), exempts boilers or process heater “into which the vent stream is introduced with the primary fuel or is used as the primary fuel.” These seems to indicate that EPA draws a distinction between the three situations described above where emissions are routed to a boiler or process heater (even though they are all three clearly covered by the definition of “routed to a process”).

The recommended changes discussed below resolve this conflict.

10.1.1 NSPS Subparts VV And VVa Include The Concept Of “Fuel Gas”

In the rulemakings for NSPS Subparts VV and VVa, EPA has addressed this same basic situation in a clear and reasonable manner. For example, §60.482-4a(c) states that:

“Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section.”

Further, Subpart VVa includes the following related definitions.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

API believes that this precedent can be utilized to improve the clarity in Subparts OOOO and OOOOa. This recommendation is provided below.

10.1.2 Recommended Change to Definition Of “Routed To A Process Or Route To A Process”

API recommends that the following changes be made to the definition of routed to a process or route to a process” in the CTG model rule.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Salable quality gas means natural gas that meets the flow line or collection system specifications, regardless of whether such gas is sold. **Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.**

API further recommends that the following definition of fuel gas be added.

***Fuel gas* means gases that are combusted to derive useful work or heat.**

10.2 Definitions Of “Control Device”, “Combustion Device”, And “Combustion Control Device”

The confusion discussed above related to boilers and process heaters and routed to a process is exacerbated by the fact that the CTG model rule does not define control device. In addition to this situation that needs to be corrected, the model rule requirements for pneumatic pumps make defining “control device” critical. This is discussed later in Section 15.4.5,

As discussed in Section 10.1.2, the definition of “routed to a process” clearly includes routing emissions to a boiler or process heater to be consumed, yet the CTG model rule discusses boilers and process heaters as control devices in other places.

In addition, the situation is further confused as EPA uses the terms “combustion device”, “combustion control device”, and “enclosed combustion control device” in an arbitrary manner that further confuses the situation. None of these terms are defined in the CTG model rule.

In conjunction with the recommended definitions in Section 10.1.2 **API offers the following definitions to be added to the CTG model rule.**

Control device means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this rule.

Combustion control device means a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.

Enclosed combustion control device means a combustion control device with an enclosure such that the flame is not an open flame.

This definition of control device, along with the definition of “routed to a process or route to a process” recognizes that routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors. Thus, routing pneumatic pump exhaust or compressor blowdown gas to be used as a fuel gas would not make heaters and boilers using these streams part of a control device.

In addition, the following changes are needed throughout the model rule to rectify the inconsistent usage of these terms throughout. These changes also address the changes related to boilers and process heaters and “routed to a process.”

E.1

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a **combustion** control device model tested under section F(d), which meets the criteria in section F(d)(11) and section F(e).

(1) Each combustion **control device** (~~e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater~~), except for a flare, must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

* * * * *

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(d) Each control device used to meet the emission reduction standard in section A.2 for a storage vessel must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a **combustion** control device model tested under F(d), which meets the criteria in F(d)(11) and F(e).

(1) For each enclosed combustion control device (~~e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater~~) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device (~~e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater~~) must be designed and operated in accordance with

one of the performance requirements specified in paragraphs (i) through (iii) of this section.

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

F

(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (75) of this section.

~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~

~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~

(42) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.

(53) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.

(64) A performance test is waived in accordance with §60.8(b).

(75) A **combustion** control device whose model can be demonstrated to meet the performance requirements of E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

* * * * *

~~(b)(3)(iv) Reserved If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

E.2

~~(b) Reserved You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~

~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~

~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~

* * * * *

~~(d)(1)(iv) Reserved For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or $\pm 2.5^{\circ}\text{C}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~

* * * * *

(d)(1)(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the **combustion** control device. The monitoring instrument must have an accuracy of ± 2 percent or better. The flow rate at the inlet to the combustion **control** device must not

exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the **combustion** control device.

11.0 THE PROPOSED BY-PASS DEVICE REQUIREMENTS ARE NOT REASONABLE AND WERE NOT JUSTIFIED BY EPA

EPA failed to consider the cost and technical feasibility of the audible alarm and notification via remote alarm at the nearest field office for non-secured by-pass device requirements. A remote alarm at a field office does not add any additional environmental benefit, where an onsite device meets the intent of the alarm requirements. There are several considerations for a field office to receive data from field locations including onsite equipment, programming, and installation and maintenance. Adding an alarm will require installation of new equipment requiring potentially a facility to be shut down and the equipment purged so that "hot work" can be performed to install the equipment which will result in additional emissions. Furthermore, a company would need a remote transmitter unit (RTU) installed or have an existing RTU with sufficient capacity to transmit a signal from the device to an operations center to notify the operations center. There are also cost from programming, installation, and maintenance of the alarm. Equipment and installation costs are several thousands of dollars for each data point, per site, routed into a system, even if existing monitoring equipment is located onsite. Ongoing support and maintenance of the monitored parameter is required to sustain operation

For bypass devices secured with a car-seal or lock-and-key type configuration, the requirement is for visual verification that the device is secured. The requirements for non-secured devices should be similar and only require verification if the alarm - whether audio or visual - has been triggered. Since there is a flow indicator present, the amount vented would be known. Following are recommended changes to the CTG model rule language:

D.1(b)(3)(i)(A)

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible **and/or visible** alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.

D.2(d)(1)

(d) For each bypass device, except as provided for in section D.1, you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere. **You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere.**

12.0 THERE IS UNNECESSARY OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSEM AND FUGITIVE EMISSION REQUIREMENTS

EPA proposes fugitive monitoring like requirements for closed vent systems, but also includes closed vent systems in the definition of Fugitive Emission Components. This results in CVS being subject to both closed vent system requirements in Section D and the fugitive emission component monitoring requirements in Section I. This creates a situation which is unnecessarily duplicative and redundant. Specifically, EPA has required both optical gas imaging monitoring for the tank cover and the closed vent systems under Section I, as well as annual Method 21 (M21) monitoring and visual inspections for closed vent systems under Section D. This could result in as many as three different leak detection programs at a single facility.

To avoid this conflict, API provides recommendations that will eliminate this overlap while still ensuring that emissions from leaks from closed vent system components are minimized. The problem and API's recommendations are discussed in detail in Section 16.0.

TECHNICAL COMMENTS

13.0 STORAGE VESSELS

13.1 The Cost Analysis For Retrofitting Existing Storage Tanks With Controls Is Inadequate

In section 4.3.1.2 of the Draft CTG, EPA describes the control option of routing emissions to a combustion device. API agrees that a combustor is one of the technically feasible options to reduce VOC emissions from storage vessels. In this section, EPA estimates the cost impacts of a combustor. These costs are summarized in Table 4-5 of the CTG. However, this cost analysis is inadequate in several respects, ranging from simple mathematical errors to the omission of cost elements that EPA includes in their own guidance. Section 10.1.1 summarizes the background for EPA's cost estimate. This is followed by section 10.1.2, which discusses the numerical errors and section 10.1.3, which shows how EPA omitted costs identified in the EPA OAQPS Control Cost Manual from the analysis.

Note that these corrections do not account for the testing, monitoring, and other compliance costs that are included in the CTG model rule, as discussed in section 9.0. If EPA maintains these onerous requirements in the final CTG, they must update the cost analysis further to include these costs.

13.1.1 Basis For Draft CTG Cost Estimate For Combustors For Storage Vessels

EPA evaluated costs for control of vapors from storage vessels as described in the 2012 Technical Support Document (2012 TSD) for NSPS OOOO.²³ As stated in section 7.3 of the 2012 TSD, cost data for a combustor were obtained from an Initial Economic Impact Analysis prepared for the proposed State-only revisions to a Colorado regulation (2008 Colorado EIA),²⁴ which were assumed to be in 2007 dollars. EPA escalated the costs to 2008 dollars using the Chemical Engineering (CE) Indices for 2007 (525.4) and 2008 (575.4),²⁵ or a factor of 1.0952. EPA also added estimated costs for operating and maintenance labor. These cost data are summarized below in Table 13-1.

²³ U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012.

²⁴ Initial Economic Impact Analysis for Proposed State-Only Revisions to the Colorado Air Quality Control Commission's Regulation Number 7, "Emissions of Volatile Organic Compounds." September 18, 2008.

²⁵ Economic Indicators: Chemical Engineering Plant Cost Index. Chemical Engineering Magazine.

Table 13-1 NSPS Subpart OOOO Cost Analyses for Combustor for Storage Vessels

		NSPS 2012 TSD Table 7-5	NSPS 2012 TSD Table 7-5
Cost Item	Basis Year:	2007	(x 1.0952) 2008
Capital Costs Items			
	Combustor	\$16,540	\$18,114
	Freight and Design	\$1,500	\$1,643
	Auto Ignitor	\$1,500	\$1,643
	Surveillance System	\$3,600	\$3,943
	Instrumentation		
	Auxiliary Equipment		
	Combustor Installation	\$6,354	\$6,959
	Indirect Installation		
	Sales Tax		
	Storage Vessel Retrofit		
	Subtotal		
	Contingency		
Total Capital Investment		\$29,494	\$32,302
Annual Costs Items			
Operating Labor	labor hours	130	130
	labor rate	\$33.51	\$36.70
	supervisory hours	19.5	19.5
	supervisory rate	\$52.85	\$57.88
	Operating Labor	\$5,387	\$5,900
Maintenance Labor	labor hours	130	130
	labor rate	\$33.51	\$36.70
	supervisory hours	0	0
	supervisory rate	\$52.85	\$57.88
	Maintenance Labor	\$4,356	\$4,771
	Subtotal Labor	\$9,743	\$10,671
	Maintenance	\$2,000	\$2,190
	Pilot Fuel	\$1,897	\$2,078
	Make-up gas		
	Data Management	\$1,000	\$1,095
	interest rate (%)	7%	7%
	equipment life (years)	15	15
	CRF	0.1098	0.1098
	Capital Recovery (\$/yr)	\$3,238	\$3,547
	Overhead		
	Administrative Charges		
	Property Taxes		
	Insurance		
Total Annual Costs (\$/yr)		\$17,878	\$19,580
Control Threshold (tpy)		6	6
	control efficiency (%)	95%	95%
	emission reductions (tpy)	5.7	5.7
Cost Effectiveness (\$/ton)		\$3,136	\$3,435

EPA evaluated costs in the draft CTG for control of vapors from storage vessels in a similar manner as for NSPS OOOO, with the costs adjusted to a 2012 basis. EPA referenced a more recent version of the Colorado Initial Economic Impact Analysis (2013 Colorado EIA)²⁶ for most of the costs, but relied on the cost given in the 2012 TSD for the surveillance system, with an adjustment of 5.69% to account for changes in cost from 2008 to 2012. In that the draft CTG is applicable to existing storage vessels, and these storage vessels would require certain alterations to accommodate the routing of vapors to a control device, EPA added a cost item in the draft CTG for "Storage Vessel Retrofit." The costs in the draft CTG are summarized in Table 13-2, with a comparison to the costs in the 2012 TSD.

13.1.2 Numerical Errors In The Draft CTG Cost Evaluation

There appear to be two numerical errors in the draft CTG cost data. One is an omission of the non-labor component of maintenance and the other is an understatement of the cost of fuel to maintain the pilot flame. The impacts on cost-effectiveness of these two numerical errors are shown in Table 13-3.

Omission of the Non-Labor Component of Maintenance.

Table 1 of the 2013 Colorado EIA includes a cost of \$2,197 for Maintenance. This should have been understood as maintenance materials, corresponding to the \$2,000 in the 2008 Colorado EIA. As in the 2012 TSD, the Maintenance line item from the Colorado EIA should have been included as a maintenance cost in addition to the cost of maintenance labor.

Miscalculation of the Cost of Pilot Fuel.

The cost of Pilot Fuel is given in Table 1 of the 2013 Colorado EIA as \$768, which is substantially lower than the value of \$2,078 from the 2012 TSD. A footnote to Table 1 of the 2013 Colorado EIA indicates that the cost was based on a fuel cost of \$3.41/ million Btu (MMBtu). A typical high heat value (HHV) for natural gas is 1,028 MMBtu/ million scf (MMscf), or 1.028 MMBtu/ thousand scf. The cost per thousand scf would then be $3.41 \times 1.028 = \$3.51/\text{thousand scf}$. Various sources give values of pilot fuel consumption ranging from 50 scf/hr²⁷ to 70 scf/hr.²⁸ At the lower consumption rate of 50 scf/hr, this would correspond to $3.51 \times 50 \times 8760/1000 = \$1,537/\text{year}$, or twice the cost given in the 2013 Colorado EIA.

Further, this pilot fuel cost (said to be based on the Henry Hub Spot Price in August 2013) of \$3.41/MMBtu does not match the assumed VRU cost offset of recovered gas that is priced at \$4/Mcf (equivalent to \$3.89/MMBtu). While this would not result in a significant increase in the cost of control for a single storage vessel, it could when amplified to include the cost of controls for the entire industry.

²⁶ Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, "Emissions of Volatile Organic Compounds," submitted with Request for Hearing Documents on November 15, 2013.

²⁷ Wyoming Department of Environmental Quality, Division of Air Quality, Proposed Revisions to the Chapter 6, Section 2, Oil and Gas Production Facilities Permitting Guidance, Technical Support Document, September 2013.

²⁸ U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. <http://www.epa.gov/ttn/catc/dir1/cs3-2ch1.pdf>

Table 13-2. NSPS Subpart OOOO versus Draft CTG Cost Analyses for Combustor for Storage Vessels

Cost Item		NSPS 2012 TSD Table 7-5 2008	Draft CTG Table 4-5 2012
Basis Year:			
Capital Costs Items			
Combustor		\$18,114	\$18,169
Freight and Design		\$1,643	\$1,648
Auto Ignitor		\$1,643	\$1,648
Surveillance System		\$3,943	\$3,805
Instrumentation			
Auxiliary Equipment			
Combustor Installation		\$6,959	\$6,980
Indirect Installation			
Sales Tax			
Storage Vessel Retrofit			\$68,736
Subtotal			
Contingency			
Total Capital Investment		\$32,302	\$100,986
Annual Costs Items			
Operating Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$36.70	\$32.00
	<i>supervisory hours</i>	19.5	19.5
	<i>supervisory rate</i>	\$57.88	\$51.03
Operating Labor		\$5,900	\$5,155
Maintenance Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$36.70	\$32.00
	<i>supervisory hours</i>	0	0
	<i>supervisory rate</i>	\$57.88	\$51.03
Maintenance Labor		\$4,771	\$4,160
Subtotal Labor		\$10,671	\$9,315
Maintenance		\$2,190	
Pilot Fuel		\$2,078	\$768
Make-up gas			
Data Management		\$1,095	\$1,057
	<i>interest rate (%)</i>	7%	7%
	<i>equipment life (years)</i>	15	15
	<i>CRF</i>	0.1098	0.1098
Capital Recovery (\$/yr)		\$3,547	\$11,088
Overhead			
Administrative Charges			
Property Taxes			
Insurance			
Total Annual Costs (\$/yr)		\$19,580	\$22,228
Control Threshold (tpy)		6	6
	<i>control efficiency (%)</i>	95%	95%
	<i>emission reductions (tpy)</i>	5.7	5.7
Cost Effectiveness (\$/ton)		\$3,435	\$3,900

Table 13-3. Draft CTG Cost Analyses for Combustor for Storage Vessels –Corrected for Numerical Errors

		Draft CTG	Draft CTG <i>corrected</i>
<u>Cost Item</u>	Basis Year:	<u>Table 4-5</u> 2012	<u>Table 4-5</u> 2012
Capital Costs Items			
	Combustor	\$18,169	\$18,169
	Freight and Design	\$1,648	\$1,648
	Auto Ignitor	\$1,648	\$1,648
	Surveillance System	\$3,805	\$3,805
	Instrumentation		
	Auxiliary Equipment		
	Combustor Installation	\$6,980	\$6,980
	Indirect Installation		
	Sales Tax		
	Storage Vessel Retrofit	\$68,736	\$68,736
	Subtotal		
	Contingency		
Total Capital Investment		\$100,986	\$100,986
Annual Costs Items			
Operating Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	19.5	19.5
	<i>supervisory rate</i>	\$51.03	\$51.03
	Operating Labor	\$5,155	\$5,155
Maintenance Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	0	0
	<i>supervisory rate</i>	\$51.03	\$51.03
	Maintenance Labor	\$4,160	\$4,160
	Subtotal Labor	\$9,315	\$9,315
	Maintenance		\$2,197
	Pilot Fuel	\$768	\$1,537
	Make-up gas		
	Data Management	\$1,057	\$1,057
	<i>interest rate (%)</i>	7%	7%
	<i>equipment life (years)</i>	15	15
	<i>CRF</i>	0.1098	0.1098
	Capital Recovery (\$/yr)	\$11,088	\$11,088
	Overhead		
	Administrative Charges		
	Property Taxes		
	Insurance		
Total Annual Costs (\$/yr)		\$22,228	\$25,194
Control Threshold (tpy)		6	6
	<i>control efficiency (%)</i>	95%	95%
	<i>emission reductions (tpy)</i>	5.7	5.7
Cost Effectiveness (\$/ton)		\$3,900	\$4,420

13.1.3 Omission Of Costs Identified In The EPA OAQPS Control Cost Manual

EPA maintains a Control Cost Manual which has the following stated purpose:

The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed.²⁹

The EPA Control Cost Manual, then, is expressly intended to provide guidance in the evaluation of the cost of control devices. The costs to be included in the evaluation of a flare as a control device are addressed in Section 3.2, Chapter 1 of the EPA Control Cost Manual. These costs include the following line items for Indirect Annual Costs:

- | | |
|--------------------------|---------------------------------------|
| - Overhead | 60% of total labor and material costs |
| - Administrative charges | 2% of Total Capital Investment |
| - Property tax | 1% of Total Capital Investment |
| - Insurance | 1% of Total Capital Investment |

EPA neglected these costs in both the 2012 TSD and the draft CTG, but has offered no rationale for doing so. The omission of these costs, then, appears to be arbitrary and capricious. The impact of these Indirect Annual Costs is shown below in Table 13-4.

13.1.4 Understatement Of Operating And Maintenance Hours

The EPA Control Cost Manual indicates an allowance of 630 hours per year for operation of a flare, and 0.5 hours per shift for maintenance of a flare. Assuming one shift per day, the estimated maintenance labor would be 182 hours. EPA, however, allowed just 130 hours per year for operating the device and another 130 hours per year for maintenance. In the 2012 TSD, EPA acknowledged the higher level of hours in the EPA Control Cost Manual, but reasoned that operating labor would be lower for these devices when used in the oil and natural gas production sector due to most of the sites being unmanned.³⁰ However, operating and maintenance hours would be increased for unmanned sites due to the travel time involved in getting personnel to the sites. It is, then, inappropriate to arbitrarily reduce estimated operating and maintenance hours for these facilities. The impacts of increasing the operating and maintenance hours to the levels indicated by the EPA Control Cost Manual are shown below in Table 13-5.

²⁹ U.S. Environmental Protection Agency, "EPA Air Pollution Control Cost Manual," EPA/452/B-02-001, Sixth Edition, January 2002. http://www3.epa.gov/tncatc1/dir1/c_allchs.pdf

³⁰ U.S. EPA, "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution," Background Supplemental Technical Support Document for the Final New Source Performance Standards, April 2012; page 7-4.

Table 13-4. Draft CTG Cost Analyses for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

		Draft CTG	Draft CTG
		<i>corrected</i>	<i>corrected, plus Indirect Annual Costs</i>
<u>Cost Item</u>	Basis Year:	<u>Table 4-5</u> 2012	<u>Table 4-5</u> 2012
Capital Costs Items			
	Combustor	\$18,169	\$18,169
	Freight and Design	\$1,648	\$1,648
	Auto Ignitor	\$1,648	\$1,648
	Surveillance System Instrumentation Auxiliary Equipment	\$3,805	\$3,805
	Combustor Installation Indirect Installation Sales Tax	\$6,980	\$6,980
	Storage Vessel Retrofit	\$68,736	\$68,736
	Subtotal		
	Contingency		
Total Capital Investment		\$100,986	\$100,986
Annual Costs Items			
Operating Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	19.5	19.5
	<i>supervisory rate</i>	\$51.03	\$51.03
Operating Labor		\$5,155	\$5,155
Maintenance Labor	<i>labor hours</i>	130	130
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	0	0
	<i>supervisory rate</i>	\$51.03	\$51.03
Maintenance Labor		\$4,160	\$4,160
Subtotal Labor		\$9,315	\$9,315
Maintenance		\$2,197	\$2,197
Pilot Fuel		\$1,537	\$1,537
Make-up gas			
Data Management		\$1,057	\$1,057
	<i>interest rate (%)</i>	7%	7%
	<i>equipment life (years)</i>	15	15
	<i>CRF</i>	0.1098	0.1098
Capital Recovery (\$/yr)		\$11,088	\$11,088
Overhead			\$6,907
Administrative Charges			\$2,020
Property Taxes			\$1,010
Insurance			\$1,010
Total Annual Costs (\$/yr)		\$25,194	\$36,141
Control Threshold (tpy)		6	6
	<i>control efficiency (%)</i>	95%	95%
	<i>emission reductions (tpy)</i>	5.7	5.7
Cost Benefit (\$/ton)		\$4,420	\$6,340

**Table 13-5. Draft CTG Cost Analyses for Combustor for Storage Vessels –
Corrected Plus Indirect Annual Costs and Full Labor Hours**

<u>Cost Item</u>		Draft CTG <i>corrected, plus Indirect Annual Costs</i> <u>Table 4-5</u> 2012	Draft CTG <i>corrected, plus Indirect Annual Costs and Full Labor Hours</i> <u>Table 4-5</u> 2012
Basis Year:			
Capital Costs Items			
	Combustor	\$18,169	\$18,169
	Freight and Design	\$1,648	\$1,648
	Auto Ignitor	\$1,648	\$1,648
	Surveillance System Instrumentation Auxiliary Equipment	\$3,805	\$3,805
	Combustor Installation Indirect Installation Sales Tax	\$6,980	\$6,980
	Storage Vessel Retrofit	\$68,736	\$68,736
	Subtotal		
	Contingency		
Total Capital Investment		\$100,986	\$100,986
Annual Costs Items			
Operating Labor	<i>labor hours</i>	130	630
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	19.5	94.5
	<i>supervisory rate</i>	\$51.03	\$51.03
	Operating Labor	\$5,155	\$24,982
Maintenance Labor	<i>labor hours</i>	130	182
	<i>labor rate</i>	\$32.00	\$32.00
	<i>supervisory hours</i>	0	0
	<i>supervisory rate</i>	\$51.03	\$51.03
	Maintenance Labor	\$4,160	\$5,824
Subtotal Labor		\$9,315	\$30,806
Maintenance		\$2,197	\$2,197
Pilot Fuel		\$1,537	\$1,537
Make-up gas			
Data Management		\$1,057	\$1,057
<i>interest rate (%)</i>		7%	7%
<i>equipment life (years)</i>		15	15
<i>CRF</i>		0.1098	0.1098
Capital Recovery (\$/yr)		\$11,088	\$11,088
Overhead		\$6,907	\$19,802
Administrative Charges		\$2,020	\$2,020
Property Taxes		\$1,010	\$1,010
Insurance		\$1,010	\$1,010
Total Annual Costs (\$/yr)		\$36,141	\$70,527
Control Threshold (tpy)		6	6
<i>control efficiency (%)</i>		95%	95%
<i>emission reductions (tpy)</i>		5.7	5.7
Cost Benefit (\$/ton)		\$6,340	\$12,373

13.2 The Emissions Threshold For Controlling Existing Storage Vessels Should Be Higher Than 6 TPY VOC

In section 4.4 of the draft CTG, EPA explains that 6 tpy of VOC was selected as the applicability threshold because this level was found to be “a cost effective applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels”. Table 13-2 through Table 13-4 showed the cost effectiveness calculation at an emissions level of 6 tpy of VOC.

However, as was demonstrated in section 13.1, EPA's cost estimate for combustors for storage vessels was flawed. After adjusting for these flaws, the cost effectiveness values change accordingly for storage vessel emitting 6 tpy VOC.

As was shown in Table 13-4, the cost effectiveness for a 6 tpy VOC storage vessel is estimated to be \$6,340 when the Indirect Annual Costs from the EPA Control Cost Manual are taken into account. This is greater than the value of \$5,700/ton that EPA deemed to be unacceptably high in related rulemaking.³¹ When the Indirect Annual Costs from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 8 tpy would be more appropriate than a threshold of 6 tpy. This is shown in Table 13-6.

Table 13-6 Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs

Total Annual Costs (\$/yr)	\$36,141	\$36,141
Control Threshold (tpy)	6	8
<i>control efficiency (%)</i>	95%	95%
<i>emission reductions (tpy)</i>	5.7	7.6
Cost Effectiveness (\$/ton)	\$6,340	\$4,755

Further, as was shown in Table 13-5, the cost per ton of emission reductions is shown to be \$12,373 for a 6 tpy VOC storage vessel when the full labor hours from the EPA Control Cost Manual. This is also greater than the value of \$5,700/ton that EPA deemed to be unacceptably high in a related rulemaking.³² When the full labor hours from the EPA Control Cost Manual are taken into account, it appears that a control threshold of 15 tpy would be more appropriate than a threshold of 6 tpy. This is summarized in Table 13-7.

Table 13-7. Cost Effectiveness Evaluation for Combustor for Storage Vessels – Corrected Plus Indirect Annual Costs and Full Labor Hours

Total Annual Costs (\$/yr)	\$70,527	\$70,527
Control Threshold (tpy)	6	15
<i>control efficiency (%)</i>	95%	95%
<i>emission reductions (tpy)</i>	5.7	14.25
Cost Benefit (\$/ton)	\$12,373	\$4,949

³¹ 78 FR 58429 (September 23, 2013).

³² 78 FR 58429 (September 23, 2013).

13.3 Adding Control To An Existing Storage Vessel To A Control Device Can Present A Safety Issue

Many existing storage vessels were not initially designed to route emissions to a control device. For these existing tanks, the integrity may not be able to withstand the back pressure from the closed vent system and control device. The high back pressure could result in tank damage or even rupture. Therefore, they will require changes to the tank, or full replacement of the tank, in order to handle the back pressure from the control device and closed vent system without damaging the tank. Most of the storage vessels in the oil and natural gas industry last only 10-15 years maximum and would eventually be subject to NSPS OOOOa due to routine replacement.

13.4 Adding Combustion Control To An Existing Storage Vessel May Cause Negative Environmental Impacts That Are More Significant Than The VOC Reductions

Combustion of gas from storage vessels not only destroys VOCs, it creates NO_x, CO, and CO₂ emissions. EPA acknowledges this on page 4-6 of the draft CTG, as they state that "Combustion and partial combustion of organic pollutants also created secondary pollutant including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates." However, EPA did not attempt to quantify these impacts.

The precursors to ozone formation are both VOCs and NO_x. The net impact of ozone formation depends on the NO_x, VOCs, and sunlight for a particular location. As noted in EPA's Integrated Science Assessment for Ozone³³, "Duncan et. al 2010"³⁴ found that O₃ [ozone] formation over most of the U.S. became more sensitive to NO_x over most of the U.S. from 2005 to 2007 largely because of decreases in NO_x emissions." The ozone formation over most of the U.S. is NO_x limited; therefore, in most areas of the country adding more NO_x could result in increased ozone formation would be counterproductive to the point of CTGs to help reduce ozone formation. Analysis for particular areas could find that the net result of controlling storage vessels actually creates more ozone. EPA should allow the states to determine whether controlling storage vessels creates or reduces ozone prior to having to incorporate the RACT recommendations in this CTG into their SIPs through analysis of the air quality for the particular area.

13.5 EPA's Does Not Define "Maximum Daily Average Throughput"

Paragraph (a) of section A.1 of the model rule states that "The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority". API agrees with this approach, except that the term "maximum daily throughput" is contradictory from both a plain text and mathematical point of view. **API suggests that the following definition be added to section A.6 of the model rule.**

³³ US EPA. 2013a. "Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final)." EPA/600/R-10/076F.

³⁴ Duncan, BN; Yoshida, Y; Olson, JR; Sillman, S; Martin, RV; Lamsal, L; Hu, Y; Pickering, KE; Retscher, C; Allen, DJ. (2010). Application of OMI observations to a space-based indicator of NO_x and VOC controls on surface ozone formation. Atmos Environ 44: 2213-2223.
<http://dx.doi.org/10.1016/j.atmosenv.2010.03.010>

Maximum average daily throughput means the daily average throughput during the 30-day PTE evaluation period that represents steady-state conditions.

13.6 The Lack Of An Alternate Uncontrolled VOC Emission Standard In The CTG Model Rule Leads To Existing Storage Vessels Being Controlled Although Emissions Have Declined Below The Applicability Threshold

Under NSPS subpart OOOO and proposed subpart OOOOa, EPA has allowed for the removal of storage vessel control devices once emissions are below 4 TPY (§60.5395(d)(2) and proposed §60.5395a(a)(3)). In the proposed amendments to subpart OOOO published on April 12, 2013 (78 FR 22126), EPA provided extensive rationale for why it was justified to include this alternative limit for storage vessels.

However, the draft CTG model rule does not include this alternative. API believes that if BSER, as required for NSPS, includes this alternative, then certainly the less stringent RACT should also include it. EPA must either include this alternative 4 TPY limit in the CTG RACT recommendation and model rule, or justify why it is not included.

From a cost effectiveness standpoint, EPA stated that below 4 tpy of VOCs controlling storage vessels was not cost effective under NSPS subpart OOOO, which was published on September 23, 2013. Following are quotes from the preamble for these final amendments (78 FR 58429).

“... our analysis indicates that the cost of controls for each storage vessel affected facility at a VOC emission rate of 4 tpy is approximately \$5,100 per ton. This cost increases to approximately \$6,900 per ton at an emission rate of 3 tpy, and to approximately \$10,000 per ton at 2 tpy. For comparison, we note that, in a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost effective at a cost of \$5,700/ton, which calls into question the cost effectiveness of continuing control of storage vessel affected facilities at an emission rate below 4 tpy.”

“In light of the cost-effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy.”

For RACT, it would definitely not be cost effective below 4 tpy.

13.7 “Well Completion Vessel” Is Not Defined In The CTG Model Rule, Which Could Lead To Confusion

In section A.6 of the model rule, the definition of “storage vessel” includes the following sentence, “A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule.” This sentence contains the following terms, which are not defined in section A.6,

- “well completion vessel”,
- “recovered liquids”,
- “well”,

- “startup of production”, and
- “flowback”.

The omission of these related definitions makes the applicability of RACT toward well completion vessels unclear.

Since the CTG model rule will apply to existing sources only, API believes that well completion vessels would not be subject, as they would be associated with new wells and regulated under the existing NSPS subpart OOOO and proposed OOOOa as potential new, modified, or reconstructed storage vessel affected facilities.

However, in order to avoid confusion, API recommends that the following definitions be added to section A.6 of the model rule. These definitions are consistent with the existing NSPS subpart OOOO and proposed subpart OOOOa (§60.5430 and §60.5430a).

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this rule.

13.8 EPA Has Not Justified The Continuous Parameter Monitoring Requirements In The CTG

In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required for storage vessels. As discussed earlier in Section 9.2.1, these NESHAP-level monitoring requirements are not appropriate for RACT. EPA has not justified these requirements and must not include them in the final CTG model rule.

However, for storage vessels the monitoring requirements in the RACT model rule are even more egregious as these RACT requirements are considerably more stringent than the BSER requirements proposed for NSPS subparts OOOO and OOOOa. For those NSPS, EPA did not propose any parameter monitoring for storage vessel control devices. RACT-level requirements should, by definition, generally be less stringent than BSER. In this case, EPA has included RACT monitoring requirements for storage vessel control device monitoring that are orders of magnitude more stringent than the BSER requirements in the NSPS. They must be removed from the model rule. **API recommends the monitoring requirements for storage vessels be consistent with those for NSPS subpart OOOOa.**

14.0 PNEUMATIC CONTROLLERS

14.1 EPA Must Clarify That Continuous Bleed Pneumatic Controllers With Bleed Rates Less Than 6 Standard Cubic Feet Per Hour Are Not Subject To Any Requirements Under The RACT Recommendation And Model Rule For Pneumatic Controllers From The Wellhead To The Natural Gas Processing Plant Or Point Of Custody Transfer To An Oil Pipeline

The CTG in section 6 proposes that each continuous bleed natural gas-driven pneumatic controllers is the affected facility for RACT by stating the following:

“RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs, including but not limited to responsetime, safety and positive actuation, requiring a bleed rate greater than 6 scfh).”

Furthermore, the CTG states on page 6-3: “It is assumed intermittent, or no-bleed, controllers meet the definition of a low-bleed.”

While API appreciates EPA recognizing the inherent low emissions of intermittent vent controllers, this statement could also be interpreted that for the purpose of this CTG that intermittent vent controllers should be considered continuous low bleed controllers.

Section B.1 provides the applicability requirements of the model rule to pneumatic controllers. Specifically for pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, paragraph B.1(b) says that the VOC control requirements apply to each “single continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.”

Paragraph B.2(c) then requires the following:

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a)(3).

Section B.1(b) is very clear that the rule only applies to pneumatic continuous bleed natural gas-driven controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour. Given the above citations from section 6, it can be interpreted to mean that all existing pneumatic controllers are subject to RACT in the CTG. However, the model rule for pneumatic controllers in Appendix B states that continuous high bleed controllers are the affected facility which is consistent with NSPS but inconsistent with the stated RACT in section 6. API recommends correcting its RACT statement in section 6 to clearly indicate that RACT applies only to continuous high bleed gas-driven pneumatic controllers and that RACT applies only to controllers constructed before August 12, 2011, the proposal date for NSPS which defines new sources.

If instead it is EPA's intent to apply RACT to all pneumatic controllers, this will setup the potential for an operator choosing to delay action until after a RACT rule becomes effective rather than take early action. While RACT is mainly for lowering emissions using emissions control, emission reduction from high bleed pneumatic controllers often requires replacement or when feasible a pilot valve retrofit to make them low bleed or intermittent vent. The cost of retrofit may also be considered a reconstruction of the controller as well in many instances. Replacing a controller with a new one or reconstructing it, will make the controller a new source and no longer an existing source, so would then be subject to NSPS not RACT. If this new replacement or reconstruction occurs before the RACT rule is effective, it could become an existing source subject to all the RACT requirements. Even where existing low bleeds and intermittent vents are already used, an operator may replace them anyway just to ensure being considered a new source rather than an existing source if this CTG doesn't clearly define the dates that separate new sources from existing sources. However, these issues are resolved if RACT applies as we recommend; only high bleed controllers are affected facilities, and existing sources are defined as construction prior to the proposal dates of Subpart OOOO or OOOOa as appropriate.

API disagrees with the CTG recommendation that all controllers should be replaced as described in section 6.5 of the RACT.

The CTG should only stipulate high bleed natural gas pneumatic controllers must be replaced, unless justifiable as consistent with the NSPS. Replacing an existing high bleed controller with a new low bleed controller or intermittent controller would cause the new controller be covered under NSPS and would not be subject to an existing source RACT rule.

API requests that EPA acknowledge this fact and provide a clear statement that continuous bleed pneumatic controllers with bleed rates less than 6 standard cubic feet per hour are not subject to any requirements under the RACT recommendation and Model Rule for pneumatic controllers from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

15.0 PNEUMATIC PUMPS

15.1 Introduction

API appreciates EPA's efforts to simplify the guidelines for pneumatic pump control requirements as well as EPA's recognition that there are limited scenarios for which control of pneumatic pumps will be cost effective. However, from review of proposal and supporting documents, it is clear that EPA did not appreciate some key technical issues as well as some key costs that would be incurred if the rule were finalized as proposed.

Each of these points is expanded upon in this section, but API recommends that the following exemptions should be added to the proposed CTGs for pneumatic pumps:

- Technical Feasibility – If it is not technically feasible to connect a pump to an existing on site control device, there should be an exemption.
- Small or limited use emission pumps (< 53 thousand scf per year emission rate, which is equivalent to a continuous 6 scf/hour emission rate) rate or any pump operating less than 90 days per year).

Additionally, EPA has proposed overly burdensome and costly testing and monitoring requirements for control systems used to control pumps. If control requirements are retained for any types of pneumatic pumps, the model rule should eliminate testing, monitoring, and recordkeeping requirements for the control device that are triggered solely due to the connection of a pneumatic pump exhaust to the closed vent system or control device. Alternatively, EPA should only require control of pumps when an existing NSPS OOOO/OOOOa control device which is already subject to the same requirements as in the proposed rule is present.

Finally, for many technical reasons, API believes it is important that EPA should clarify in the CTGs that the presence of a heater or boiler should not be considered to be equivalent to presence of control device.

Given that the CTGs mirror the requirements under the proposed NSPS OOOOa, API also appreciates EPA's discussion in the NSPS preamble that recognizes the limitations of solar powered pumps, the typical unavailability of electricity at well sites and other remote sites, and the fact that gas-assist lean-glycol recirculation pumps on glycol dehydration units are not pneumatic pumps. API agrees with EPA's approach of defining the affected source as only pumps using natural gas as the pneumatic power source and located at a site with an existing control device. API also agrees with EPA's approach of only requiring control of new, modified or reconstructed pneumatic pumps on sites with existing control devices (combustion control or vapor recovery). However, API has several important issues with the details of the CTG as proposed.

- EPA inappropriately requires an existing control device/system to meet the closed-vent-system, performance testing, monitoring, and recordkeeping requirements of NSPS OOOOa. This is exacerbated by the proposal to require the same measures as for wet-seal centrifugal compressor affected source control devices.
- API believes the capital cost estimate EPA made is low and that several significant cost items are left out of the cost analysis.
- API believes the estimated emissions per pump for diaphragm type pumps is overestimated and the equal proportional split between piston type chemical pumps and diaphragm pumps is incorrect. Due to the limited time available for comment, API did not have time survey members adequately, but there are many more piston pumps installed than diaphragm pumps.
- Because the cost is underestimated and the emissions overestimated, the control actions required by the regulation are not cost effective in many instances.

- EPA failed to recognize important design and process factors that could render routing a pneumatic pump to an existing control device technically infeasible or unsafe.
- Some details of the model rule language are unclear or not defined fully.

Each of these issues is discussed in more detail in the following sections.

15.2 Control Device And Closed Vent System Requirements

As written, control devices not subject to Subpart OOOO or OOOOa would be required to be used to control emissions from pneumatic pumps. It is not clear if this was EPA's intent in writing the model rule. From the lack of consideration for performance requirements, performance testing, closed vent system monitoring, recordkeeping, and reporting compliance costs in the economic analysis, it appears that EPA did not intend for control devices not subject to Subpart OOOO or Subpart OOOOa to be pulled into the monitoring, reporting, and recordkeeping requirements under the CTGs. If EPA maintains a requirement to route higher emitting pneumatic pumps to existing control devices, this should not trigger the performance specifications, performance testing, monitoring, closed vent system monitoring, recordkeeping, and reporting requirements for the control device if it is not already subject to regulation under Subpart OOOO or Subpart OOOOa. This change from the proposed approach would address one of the two critical cost elements ignored by EPA when assessing the cost of control; specifically, the costs of testing, monitoring, reporting, and recordkeeping requirements.

EPA should also provide for routing of pump exhaust from glycol heat medium pumps (typically diaphragm type pumps) to a controlled tank or knock-out drum prior to the control device to provide for buffering the intermittent flow when the pump exhaust stroke occurs. This would provide for more stable flow to the control device and piping system and simplify connecting a pneumatic pump exhaust to an existing control system.

The draft CTG unnecessarily and inappropriately requires existing control devices and closed vent systems to comply with the full suite of requirements identical to those specified for control devices and systems on centrifugal compressor affected facilities degassing tank vents if a new, modified, or reconstructed pneumatic pump affected source is routed to the control device. EPA failed to recognize that the majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. Since centrifugal compressors are rarely used in the production segment and new, modified, or reconstructed centrifugal compressors in the gathering & collection, processing, and transportation & storage segments are almost certainly dry seal equipped, the probability is near zero that an existing control device on well sites or remote facilities would already be subject to the centrifugal compressor affected source requirements for closed vent systems and control devices. Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. Even where an existing control device and closed vent system has applicable requirements under Subpart OOOO, these are almost certainly those requirements for control devices and closed vent systems installed on storage tank affected sources rather than centrifugal compressor affected sources and thus would have new requirements under the proposed rule. This could subject an individual control device and closed vent system to a dual set of requirements if the proposed rule is finalized as proposed. Note that this discussion focuses

on enclosed combustion control devices as sites with VRU's are likely to have electricity and hence no pneumatic pump affected sources.

By requiring existing closed vent systems and control devices to comply with the specified requirements listed in sections D.1, D.2, E.1, and E.2 of the draft CTG retroactively applies unnecessary, burdensome, and costly requirements to existing control devices and systems that were not designed, installed, or intended to comply with these requirements. Note also that none of the additional costs are included in EPA's analysis of the reasonableness of controlling pneumatic pump affected sources and the additional costs are likely to render such control not reasonable - cost analysis details are presented in a separate section of these comments.

- Section D.1 and D.2: An existing closed vent system may not be designed or constructed to meet the standard of "no detectable emissions" specified. Again, this may force retrofit or replacement of the existing piping system to enable meeting the "no detectable emissions" requirement.
- Section E.1: Existing control devices and the piping to them are not likely to have the necessary ports installed to enable performance testing as specified and would have to be taken offline in order to retrofit them if retrofit is even possible.
- Section E.2: Existing control devices are unlikely to have all of the monitoring instruments and capabilities required for continuous compliance demonstration as required and these would have to be retrofitted to the control device. Again, retrofit may not be possible which would leave an operator with no avenue to comply without installing a new control device which EPA already found to be not reasonable from a control cost standpoint. Additionally, the data monitoring, logging and averaging required under E.2.c would require either installation of an entirely new monitoring system or tying the monitoring devices into an existing automation system programmable logic controller (PLC) which may not have the number of input ports necessary nor have the memory and computing power necessary. Due to the typical lack of electrical power, the installation of a monitoring system would also require installation of a solar power system with the necessary power to operate the system and the necessary battery back-up to assure adequate data recovery.

Requiring control devices and covered vent systems, where a pneumatic pump affected source is routed to them, to comply with the performance testing, continuous monitoring, and associated requirements of the draft CTG is not necessary. The exhaust from a pneumatic pump affected source is the same natural gas used for the pilot flame in a combustion control device and as fuel for a boiler or heater. It is not difficult to combust and should not require the same rigor of demonstration for more difficult to combust compounds. In general, the low molecular weight straight chain aliphatic hydrocarbons that characterize the natural gas industry, including associated gas, are easy to combust.

To address the issues regarding retroactive application of the requirements in sections D and E of the CTGs to existing control devices and closed vent systems not already subject to the requirements proposed, API recommends EPA take one of the following approaches.

- Maintain the current definition of pneumatic pump affected source and require that the existing control device and closed vent system comply with whatever existing requirements for testing, monitoring, and reporting exist for the particular site/control device and closed vent system.

-or-

- Redefine the pneumatic pump affected source as only those new, modified, or reconstructed natural gas powered pneumatic pumps installed at a site with an existing control device that is already subject to the requirements contained in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a proposed in the rule.
- To assure the integrity of the newly installed piping routing a new, modified, or reconstructed pneumatic pump affected source to an existing closed vent system or directly to the control device EPA could require an annual leak inspection with an Optical Gas Imaging camera for the newly installed piping to an existing control device or closed vent system.

15.3 Technical Basis For RACT Recommendation

15.3.1 EPA Underestimated The Cost Of The Proposed Control Strategy Which Renders Is Not Cost Effective In Many Situations

In the cost analysis for the proposed control strategy for pneumatic pumps, EPA incorrectly only listed a one-time capital cost impact of \$2,000 for the design and installation of piping to route vapors from the exhaust of a pneumatic pump to an existing control device. This value was based upon Natural Gas Star program data.³⁵ Using a 7% interest rate, EPA estimated the annualized cost of controlling a pneumatic pump at \$285/year. This value is too low and does not include significant cost items required by the rule. As an example, EPA assumed a cost of \$23,252 for tying a wet-seal centrifugal compressor seal-oil degassing tank into an existing control device. (See Section 8.4.4.3 of Technical Support Document for NSPS Subpart OOOOa and Table 5-8 in the draft CTG document.) The low pressure nature of both pneumatic pump exhaust and a seal-oil degassing tank are similar. Unfortunately, the discussion of pneumatic pump control and seal-oil degassing control is not detailed enough to understand the difference in EPA's cost estimates.

API believes the average capital cost (inclusive of engineering) that would be incurred for design evaluation, designing, and construction of the piping to tie a pneumatic pump into an existing control device/system would be closer to \$5,800 and would vary considerably from site to site.

Following are the details of API's initial capital cost estimate.

- Collecting the site specific information on an existing control device/system and performing an engineering evaluation of the ability to safely and technically add pump exhaust gas to the control device/system. 8 hours of engineering time at \$185 per hour = \$1480.
- Evaluating the specific pump's ability to tolerate the exhaust backpressure necessary to route to the existing control device/system; designing the piping necessary to route a pump exhaust to the control device/system; specifying materials, connection points, and connection types for routing a pump exhaust to the control device/system; and writing a work-order and procedure for connecting. Eight (8) hours of engineering time @ \$185 per hour = \$1480.

³⁵ <http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf>.

- Ordering and collecting materials for installing the piping, commissioning a contractor to perform the work, and overseeing the work. Six (6) hours of construction specialist time at \$140 per hour = \$840.
- Travel to the site, installation of the piping for tie-in, verification of the proper functioning of the tie-in and travel from the site. One day of a contract construction crew time at \$2,000 per day = \$2,000.

Utilizing EPA's assumed 7% interest rate, this equates to an annualized initial capital cost of \$826 rather than EPA's value of \$285.

In addition to underestimating the capital costs of routing the emissions to a control device, EPA did not consider other significant initial and reoccurring costs that would be incurred. The draft CTG requires an existing control device and closed vent system with a pneumatic pump routed to them to comply with the same performance testing, closed vent system, continuous monitoring, and recordkeeping and reporting requirements applicable to closed vent systems and control devices specified for centrifugal compressor affected facilities. The majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. The probability is near zero that an existing control device subject to the centrifugal compressor affected source requirements for closed vent systems and control devices will be on a site where a pneumatic pump source is located.

Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. As such, costs not included in EPA's analysis are:

- The costs for an initial M21 demonstration that the closed vent system, at a site not already subject to the requirements under Subpart OOOO, is operating with no detectable emissions.
- The costs for initial and periodic performance testing of a control device that is not already subject to the required performance testing.
- The costs for monthly smoke inspections, including travel to and from the site for a trained visual smoke inspector.
- The costs for design, installation and maintenance of a parametric monitoring system.
- The recordkeeping and reporting cost.

The table below provides a more complete estimate of the costs associated with implementing the proposed rule requirements for pneumatic pumps. This table reflects the true cost of compliance with the CTG, including potential source testing, the need to install monitoring equipment, and the costs of conducting recurring inspection and equipment maintenance that would all be triggered by the proposed compliance requirements. Note that none of the performance testing exemptions listed in E.2(b) are considered. It should be noted that:

- Heaters with a design capacity of 44 MW (150 million BTU/hr) will not occur in the types of sites where pneumatic pump affected sources will be used

- Heaters used at well sites and other remote sites are likely to be seasonally used, or have intermittent firing dependent on heat demand and hence will not be able to accept the exhaust gas from a pneumatic pump as part or all of the fuel at all times
- As discussed previously, an existing control device is almost certainly not already subject to the performance testing requirements of the CTGs and hence not manufacture certified.
- Hazardous waste incinerators or hazardous waste fueled heaters will not occur at the type of sites where pneumatic pump affected sources will be used.

Table 15-1 Pneumatic Pump Control Cost Table

<i>Cost Item</i>	<i>Initial Cost</i>	<i>Annualized Cost</i>
<i>Capital Costs (including engineering)</i>	\$5,800	\$826
<i>Option 1 Combustor Testing (repeat each 5 years)</i>	\$6,000	\$1,200
<i>Option 2 Process Heater Testing (repeat each 5 years)</i>	\$6,000	\$1,200
Annual M21 & Visual CVS Inspection (<i>Contractor or Trained Technician - 1/2 day with vehicle</i>)	\$600	\$600
Monthly 15 min Smoke Check (trained operator inspection - \$160/month)		\$1,800
Flow Monitor, Thermal Dispersion Meter	\$5,000	\$712
CPMS - install measurement device and solar panel	\$9,000	\$1,282
CPMS - Annual Maintenance (contractor 1/2 day)		\$600
Annual CPMS Auditing (trained instrument technician complete with equipment and vehicle - 1/2 day)		\$600
<i>Scenario</i>	<i>Annualized Total</i>	
<i>Sites with Affected Pneumatic Pumps & Combustor field performance test</i>	\$6,908	
<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$6,420	
<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)</i>	\$6,908	
<i>Sites with existing Subpart OOOO or OOOOa affected storage tank with control device</i>	\$3,308	
<i>Sites with existing Subpart OOOO or OOOOa affected compressor with control device</i>	\$826	

Table 15-2 Retrofit Costs for Control Devices

<i>Cost Item</i>	<i>Initial Cost</i>	<i>Annualized Cost</i>
<i>Retrofit control device with new or relocated ports to enable performance testing per Section F. (likely to occur)</i>	\$3,000	\$427
<i>Retrofit closed vent system to meet "no detectable emission" requirement per Section D.1(b) (less likely to occur)</i>	\$3,000	\$427

Table 15-3 Average Pneumatic Pump Emission Rate (Reproduced from TSD)

	Tons/year Methane	Tons/year VOC
Piston Pump	0.38	0.11
Diaphragm Pump	3.46	0.96

Combining the complete estimate of actual costs for routing a pneumatic pump affected source to an existing control device with the emission estimates for piston pumps and diaphragm pumps from the CTGs and Technical Support Document (repeated in proposed NSPS OOOOa rule preamble) yields the following tables of control cost per ton for VOC.

Table 15-4 Piston Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

		Single Pollutant Approach
	<i>Scenario</i>	VOC Only
Production Piston Pumps	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$62,797
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$58,362
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$62,797
	<i>Sites with existing subpart OOOO or OOOOa affected storage tank with control device</i>	\$30,070
	<i>Sites with existing subpart OOOO or OOOOa affected compressor with control device</i>	\$7,509

¹. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

Table 15-5 Diaphragm Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	<i>Scenario</i>	Single Pollutant Approach
		VOC Only
Production Diaphragm Pump	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$7,196
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$6,687
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$7,196
	<i>Sites with existing subpart OOOO or OOOOa affected storage tank with control device</i>	\$3.446
	<i>Sites with existing subpart OOOO or OOOOa affected compressor with control device</i>	\$860

¹. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 14-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard cost effectiveness, the proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: “In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of \$5,700 per ton.**”

As illustrated above, for piston pumps, the control costs exceed the reasonable cost of control per ton for all possible scenarios.

For diaphragm pumps, the cost effectiveness values shown above are lower due to the higher emissions. However, as discussed further in 15.3.4, diaphragm pumps are generally used for heat tracing and as such are not used everywhere and, when they are used do not operate year round. Using a more realistic estimate of 4 months of operation per year, the emissions from these pumps are actually 1/3rd the level assumed by EPA. The table below reflects the cost effectiveness of controlling diaphragm pumps after accounting for their non-year round operation.

Table 15-6 Diaphragm Pump Control Cost Effectiveness (assuming 4 months of annual pump operation)

	<i>Scenario</i>	Single Pollutant Approach
		VOC Only
Production Diaphragm Pump	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$21,587
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$20,062
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$21,587

<i>Sites with existing subpart OOOO or OOOOa affected storage tank with control device</i>	\$10,377
<i>Sites with existing subpart OOOO or OOOOa affected compressor with control device</i>	\$2,581

¹. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 15-2. Inclusion of these costs would only further increase the cost effectiveness ratios.

After accounting for the non-year round operation of pneumatic pumps, the only reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the CTGs. As explained in more detail earlier in these comments, the probability of this occurring is near zero.

This illustrates the need for EPA to revise the draft CTG approach to performance testing and monitoring for control devices and closed vent systems used for pneumatic pump affected sources as previously explained earlier in these comments.

It is important to note that the above costs assume that the control device and closed vent system existing on site has enough design margin to accommodate the tie-in of a pneumatic pump and that such a change to site configuration does not trigger the need for a revision to the site's air permit.

15.3.2 EPA Did Not Consider or Provide For Instances Where Routing A Pneumatic Pump Affected Source To An Existing Control Device Is Not Technically Feasible Or Where The Control Device Belongs To Another Party

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

In some instances an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

EPA should provide exclusion in the CTGs such that routing a pneumatic pump affected source to an existing control device or closed vent system is not required if it is not technically feasible or if the control device is not owned and operated by the site operator. Proposed updated rule language is included in 15.4.1.

If needed, EPA could provide provisions in the rule for an operator to make an engineering determination that an existing control device cannot technically handle the additional gas from a pneumatic pump affected source exhaust, document this determination, and make such a determination available for inspection by EPA or other competent authority.

15.3.3 EPA Did Not Consider How CTG Requirements to Route Pneumatic Pumps To Control Devices Can Potentially Trigger Permitting Requirements.

Under draft CTG, EPA is requiring that the exhaust from pneumatic pumps be controlled by control devices if those devices are present on site.

EPA's analysis of the proposed approach to pneumatic pumps has ignored the fact that such an action may require amending the air permit for a facility simply due connecting a pump to a control device. In many cases, the act of tying a new stream into a combustion control device will result in a change in emissions from a site due to the rerouting, which can trigger permitting. Local permitting requirements are very sensitive to the reality that control devices are subtle and complex engineering structures that have very real physical limits. As discussed above, EPA's proposal for natural gas pneumatic pumps seems to ignore these physical realities.

EPA has not accounted for any time or expense associated with this permitting action, nor have they considered any of the additional burden on permitting authorities. These impacts should be quantified and considered prior to finalizing the CTG requirements that may trigger state permitting requirements. One alternative to this concern is to revise the affected source criteria so that a pneumatic pump would not be an affected source, if it was connected to a control device on site. This could be accomplished by revising the text of H.1 as follows:

Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment ~~for~~ which **has not been connected to** a control device **when one** is located on site.

An additional advantage of this approach is that it clearly removes the addition of monitoring and performance testing currently in the proposed rule. As discussed in Section 15.3.1, these costs were not included in EPA's cost effectiveness analysis, nor should compliance assurance requirements from OOOOa be required for a control device that was installed for another purpose.

15.3.4 EPA Overstated The Emissions, And Therefore The Benefits, Of The Proposed Requirements For Pneumatic Pumps

EPA has overestimated the emissions from diaphragm pumps. As EPA notes in Section 7.2.1 of the CTGs: "Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks." As such, these pumps only during the winter season which represents a fraction of the year on average. Yet, EPA has assumed these pumps operate 8,760 hours per year when estimating emissions. This assumption grossly inflates the actual emissions from these sources. A more realistic estimate would be that these sources would operate 3-4 months during the course of the

year and rarely more than 8 months per year. See discussion of cost effectiveness values in Section 15.3.1, including consideration of operation of diaphragm pumps for 4 months/year.

Diaphragm pumps are also used intermittently to transfer bulk fluids such as engine oil or emptying a sump. When used for these types of service they do not run for long periods, are not large emission sources and should not be covered by the CTGs.

API recognizes the need for EPA to simplify analysis for assessing cost benefits for the development of the CTGs. EPA presents values in Section 7 of the CTGs which are based on a number of assumptions. It should be noted that the exhaust rates from pneumatic pumps are, in reality, based on assumed pump rate, a gas-supply pressure, and a pump model. All of these values vary considerably from site to site and even from pump to pump on a given site. When one reviews several manufacturer's pumps, it is readily apparent that they all have a multiplier factor for calculating required supply pressure and allowable exhaust pressure and these factors vary by over two orders of magnitude from one pump model to the next.

15.4 Applicability/Definitions

15.4.1 The CTG Should Have An Exemption For Limited Use/Low Emission Pumps Such As Chemical Injection Pumps

API believes EPA's intent to regulate pneumatic pumps that have lower emission rates than continuous low bleed pneumatic controllers is inappropriate. EPA has previously determined that continuous bleed pneumatic controller devices emitting less than 6 scf/hour did not require control and EPA continues to support that position in the NSPS OOOOa rule proposal. EPA's Technical support document shows the assumed emission rate from pneumatic piston (chemical and methanol) pumps to be 2.48 scf/hour, which is less than half the 6 scf/hour threshold for continuous bleed pneumatic controllers. The cost effectiveness of controlling such low emitting pumps is substantially above EPA's assumed \$285/ton as described Section 15.3.1. Piston pumps in services with emissions below 52,000 scf/year (equivalent to 6 scf/hour annualized) should be exempt due to the low volume of gas exhausted. Demonstration of emissions below this threshold should be a one-time engineering calculation for individual pumps or a class of pumps in similar service - for example chemical/methanol pumps below a pressure & volume combination which would yield exhausted volumes above the threshold.

There are also natural gas-driven pneumatic pumps, typically diaphragm pumps, that are used intermittently to transfer bulk liquids. These are generally either manually operated as needed or are triggered by a level controller. For instance, there are engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, separator knockout drum pumps, etc. that are used to pump liquids from one place to another. These pumps do not run continuously or even seasonally for long periods, but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, there should be an annual venting limit and an exemption for intermittently operated pumps.

EPA should provide an exemption under the rule for any pump emitting at a rate less than the rate of a continuous low bleed pneumatic controller. Specifically, any pneumatic pump which emits less than 53,000 scf/year (i.e. 6 scf/hour for an entire year) should be exempted. This would provide a reasonable exemption for intermittent use pneumatic pumps which do not have large aggregate emissions, including diaphragm pumps that are operated manually, triggered by a level controller, or operated temporarily or seasonally.

Alternatively, EPA could use the operating time of a pump with exhaust rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document) that would result in 53,000 scf/year of emissions, which is 96.5 days. This could be rounded down to 90 days of operation, or 2,160 hours. This approach would simplify the exemption, as companies would track the hours of operation instead of calculating the exact exhaust rate.

API proposes the following updates to the applicability text under H.1 of the model rule:

Each pneumatic pump, which is a natural gas-driven chemical/methanol or natural gas-driven diaphragm pump located at a natural gas processing plant or located from the wellhead and point of custody transfer to the natural gas transmission and storage segment with an exhaust rate greater than 53,000 scf/year and operates more than 2,160 hours per year and for which a control device owned and operated by the owner and operator of the pump is located on site and not demonstrated to be technically infeasible to control.

15.4.2 The Rule Text Should Exempt Portable Pneumatic Pumps

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. Since these pumps will, by their very nature, result in very low emissions, portable pumps should be exempt from the rule. Such an exemption would be analogous to that provided to portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform) engines relative to the NSPS RICE rules.

API recommends that EPA update the definition of pneumatic pump under the rule to exclude temporary and portable pumps.

EPA should amend the definitions in the draft rule language under Section H to address these temporary and portable sources, i.e. "A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source)." (See revised definition under 15.4.3)

15.4.3 The CTG Text Should Be Clearer On Exclusion Of Lean Glycol Circulation Pumps (Often Referred To As Kimray Pumps) On Dehydration Units (As Intended By The NSPS OOOOa Preamble Language)

EPA's intent is clear in the Preamble (FR 56627) to NSPS Subpart OOOOa that EPA is not proposing to regulate glycol dehydrator pumps under that rule, but the draft CTG text is not as clear on this point.

EPA can improve this by editing the definitions in the CTGs draft rule language. The two definitions below are inconsistent; however, it is noted that neither defined term is used in the CTG text itself. EPA should remove the two definitions below.

~~"Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection."~~

~~"Natural gas-driven chemical/ methanol or diaphragm pump means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas."~~

These definitions should be replaced with the following definition:

“Natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump means a gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a pump subject to the CTGs if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source).”

15.4.4 The Rule Should Allow For Removal Of Control Device – I.E. Pneumatic Pump No Longer Has To Be Controlled If Control No Longer Present

If a control device is no longer needed for the purpose for which it was originally installed, EPA should clarify that any pneumatic pumps that were routed to the device should no longer require control. A control device should not be required to remain in service only for the purpose of controlling one or more pneumatic pumps.

For example, NSPS subpart OOOO allows for removal of control device from a storage vessel if emissions fall below a certain level. Specifically, under the NSPS, EPA has allowed for the removal of control devices once emissions are below 4 TPY (40 CFR 60.5395(d)(2) and 60.5395a(a)(3)). In the preamble to the NSPS OOOO revisions dated April 12, 2013 (Federal Register Vol. 78, No. 71, 22133-22134) EPA also noted that removal of control at 4 TPY will help relieve the control device shortage issue as well as reduce emissions from burning more pilot gas than the waste gas being burned. If a control device is removed, the requirement to route pneumatic pump exhaust to the control device should no longer be applicable.

15.4.5 EPA Must Define “Control Device” In The Context Of Its Use In The Requirements For Pneumatic Pumps

H.2(b)(1) states:

Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section.

Control device is not a defined term and should be specifically defined to clarify EPA's intent which, from review of the complete NSPS OOOOa proposal and TSD, appears to be to utilize combustion control devices and/or VRUs if available. This issue is discussed in Section 10.0, and a definition recommended that will eliminate the issues related to the uncertainty of when the pneumatic pump requirements apply.

However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must make revisions within section H of the CTG model rule to clarify this situation. Specifically, API recommends the following change:

H.2(b)(1) Each natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, for which a control device is located on site, must reduce natural gas emissions by 95 percent, except as provided in paragraph (b)(2) of this section. **For the purpose of this section, boilers,**

process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.

15.4.6 The Control Device Must Be Owned and Operated By The Pump Owner and Operator

EPA must be clear that a control device on site must be owned and operated by the same company that owns and operates the pumps. For instance, the dehydration unit located on a production site may be owned and operated by the gathering company, not the producer. If there is a dehydration unit on site with a control device that is owned and operated by the gathering company, the producer has no right to route pump exhaust to the control device and should not be required to route the pump exhaust to the dehydration control device owned and operated by a separate entity.

15.4.7 Heaters Should Not Be Considered As Existing Control Devices (i.e. Pneumatic Pump Exhaust Should Not Be Required To Be Routed To A Heater Simply Because One Is Present)

The language in section E.1 of the model rule describes requirements that each control device must meet and this list includes process heaters. This language could be misinterpreted to mean that any process heater should be considered a control device and thus, its presence would require routing of a pump exhaust to the heater. It is not believed that this was EPA's intent.

EPA should clarify that routing emissions to a process heater should be considered "routing to a process" and the heater should not be considered as a control device. More discussion on this topic is provided in section 10.0. However, if EPA does not elect to incorporate API's suggested changes in section 10.0, then EPA must make revisions within section H of the CTG model rule to clarify this situation. The recommended changes are shown above in section 15.4.5.

15.4.8 Non-Affected Facilities (e.g., Pumps Not Requiring Controls Under The CTGs Should Not Have Obligations Under The Rule)

H.3(c) states

(c) You own or operate a natural gas-driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in section H.5(a)(1)(i).

EPA should remove the requirements requiring certification for pumps located at sites without control devices. Specifically, H.3(c) should be removed from the draft CTGs.

15.4.9 The CTGs Should Not Include An Ongoing Requirement To Review The Status Of The Addition Of A Control Device

Section H.2 of the draft CTGs states:

(b)(2) You are not required to install a control device solely for the purposes of complying with the 95 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on site by the compliance date specified by your regulatory authority, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

- (i) Submit a certification in accordance with H.5(b)(1)(i).*
- (ii) If you subsequently install a control device, you are no longer required to submit the certification in H.5(b)(1)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with H.5(a)(1)(iii).*

Companies typically do not track serial numbers on pumps, particularly small piston pumps for chemical injection. The pumps are often swapped out and moved around as needed for chemical injection. Typically pumps are purchased in bulk and maintained in a warehouse to install as needed. Trying to keep track of where these pumps are located and a control device is later added will be very difficult.

The applicability of control requirements in the CTGs should be based on an effective date of the CTG and not the construction, modification, or installation of a control device.

15.5 Reporting And Recordkeeping

15.5.1 Remove The Tagging Requirement.

It is unclear what EPA's intent is for requiring tagging of affected natural gas driven pneumatic pumps under H.2(a)(2), H.2(b)(3), and H.3(d). The applicability is clearly stated. The tagging appears to add little value.

API requests that EPA remove the following paragraphs related to tagging:

~~H.2(a)(2) Each natural gas driven pneumatic pump at a natural gas processing plant must be tagged with the date the natural gas driven pneumatic pump is required to comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that gas driven pneumatic pump as required in section H.5(a)(1)(i).~~

~~H.2(b)(3) Each natural gas driven pneumatic pump located between the wellhead and point of custody transfer to the natural gas transmission and storage segment for which a control device is located on site must be tagged with the date that the pneumatic pump must comply with the model rule (as established by the regulatory authority) that allows traceability to the records for that natural gas driven pneumatic pump as required in section H.5(a)(1)(ii).~~

~~H.3(d) You must tag each natural gas driven pneumatic pump subject to VOC emission requirements according to the requirements of section (a)(2) or (b)(3), as applicable.~~

Building on section 15.4.9, if any tagging is retained, it should be to document that (a) no control device was not onsite as of the CTG effective date and therefore no further action would be needed at any time under the CTG or (b) that a pump is located with a control device on site, but the control has been determined to be technically infeasible.

15.5.2 EPA Should Remove The Recordkeeping Requirements For Control Devices And Closed Vent Systems

As discussed in Section 15.3.1, EPA's costs for controlling pneumatic pumps did not include the cost of the recordkeeping and reporting requirements in the cost estimate. The recordkeeping and

reporting requirements that EPA has included are burdensome in some cases and expand requirements to non-affected sources.

- H.3(c) requires certification of non-affected sources (Section 15.4.8).
- H.4 requires testing data to be submitted that is not accounted for in the cost analysis, not cost effective when included, and not needed based on the exhaust gas being natural gas, which is the same as the pilot of the combustion device (Section 15.2). EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements.
- H.5(a)(1)(i) – It is not clear what EPA means by records of “the manufacturer specifications”. EPA should clearly specify what they want here. It is assumed this refers to the make model of the pump.
- H.5(a)(1)(ii) – Having to continue to track the data of a pump being constructed, reconstructed, or modified at a non-natural gas processing plant location that did not have a control device that later has one installed. Pumps should only be triggered at the time the pump is installed. With the movement and replacement of pumps, keeping track of such information will be extremely difficult. (See Section 15.4.9)

In many instances, these controls have been installed under a state permit (or other regulatory requirement) and have compliance assurance requirements associated with those requirements. It is inappropriate to add new compliance assurance requirements that may conflict to the original requirements the control device was installed to meet. Additionally, the control device may not be able to meet or be retrofitted to meet (i.e. install sample ports) to meet the compliance assurance requirements of the CTG model rule.

API recommends the amendments to the draft rule language as outlined for pumps in these rule comments and those below.

H.5(b)(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1)(i) through (iv) of this section.

~~(i) In the initial annual report, a certification that there is no control device on site, if applicable.~~

(ii) An identification of each natural gas-driven pneumatic pump, including the identification information specified in section H.2(a)(2) or (b)(3).

(iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.

(iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

~~(v) If complying with H.2(b)(1) with a control device tested under section F(d), which meets the criteria in section F(d)(11) and section F(e), records specified in paragraphs (a)(1)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

H.5(a)(1) For each applicable natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (iii) of this section onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the model rule (as specified by the regulatory authority), location and

~~manufacturer specifications~~ make and model for each natural gas-driven pneumatic pump.

- (ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in section H.2.
- (iii) ~~Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~
- (iv) ~~Except as specified in paragraph (a)(iv)(G) of this section, records for each control device tested under section F(d) which meets the criteria in section F(d)(11) and section F(e) and used to comply with H.2(b)(1) for each pneumatic pump.~~
 - ~~(A) Make, model and serial number of purchased device.~~
 - ~~(B) Date of purchase.~~
 - ~~(C) Copy of purchase order.~~
 - ~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~
 - ~~(E) Inlet gas flow rate.~~
 - ~~(F) Records of continuous compliance requirements in F(e) as specified in paragraphs (a)(1)(iv)(F)(1) through (4) of this section.~~
 - ~~(1) Records that the pilot flame is present at all times of operation.~~
 - ~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~
 - ~~(3) Records of the maintenance and repair log.~~
 - ~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~
 - (G) As an alternative to the requirements of paragraph (a)(1)(iv)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

16.0 EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In D.2(b) of the CTG model rule, EPA included initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, the model rule includes a fugitive emissions program in Section I that is also based on identifying and repairing leaks. Section I will also apply to covers and closed vent systems, as the definition of "fugitive emissions component" includes "closed vent systems," and "thief hatches or other openings on storage vessels." This results in covers and CVS being subject to both the leak detection and repair requirements in Section I and the leak detection and repair requirements in Section D. This creates a situation which is unnecessarily duplicative and redundant.

Table 16-1 provides a summary of these overlapping requirements.

Table 16-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO

Affected Equipment/Components	D.2		I	
	Inspections	M21	OGI	M21
closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (<i>e.g.</i> , a welded joint between two sections of hard piping or a bolted and gasketed ducting flange)	(a)(2) annual visual inspections for defects	(a)(1) Initial, annual, and after repairs/replacements	Initially, semiannually (could move to quarterly or annual depending on % leakers), and after repair/replacement	Option for use after repair/replacement
Closed vent system components other than a joint, seam, or other connection that is permanently or semi-permanently sealed	(b)(3) annual visual inspections for defects	(b)(1) and (2) Initial, annual, and after repairs/replacements		
Covers	(c) annual visual inspections for defects	n/a		

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the CTG (Table 9-4 and Table 9-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in Section D. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

16.1 Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in the CTG model rule. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

"Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from

regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards."

API recommends the same definition of closed vent system be added to the CTG model rule with an additional clarification (**bold**) that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

*Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.*

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of "routed to a process or route to a process" and "fugitive emissions component", as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

16.2 Remove Cover and Closed Vent Systems Components From Definition Of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of "fugitive emissions component" in I.6 needs to be modified.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, ~~flanges, closed vent systems, thief hatches or other openings on a storage vessels,~~ agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 17.2.1.

16.3 Remove Section D.2

API recommends that all paragraphs of Section D.2 be removed. As shown in Table 16-2 every relevant requirement of D.2 will be addressed by referring to a requirement in Section I, or in the case of the bypass requirements, requirements in D.1. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components.

Table 16-2 Side-by-Side Comparison of CTG Model Rule Section D.2 and Section I Closed Vent System and Cover Requirements

D.2	Section D.2 Requirement	I	Section I Requirement
(a)	CVS Joints, seams and other connectors - Initial M21 and annual visual inspections.	I.2 – I.4	All components – OGI monitoring initial and semi-annual
(b)	Other CVS components - Annual M21 and annual visual inspections		
(c)	Covers - Annual visual inspection		
(d)	Bypass	n/a	Not addressed in section I, but completely addressed in D.1(b)(3)
(e)	M21	not needed	Not needed
(e)(1)-(8)	M21 requirements		
(e)(9)	Repairs - First attempt within 5 days, repair within 15 days.	I.2(f)(1)	Repairs - Repair within 15 days.
(a)(2)	For CVS Joints, seams and other connectors only – monitor using M21 after repair/replacement	I.2(f)(2)	Resurvey (all components) using OGI or M21 within 15 days of repair
(e)(10)	Delay of repair - If technically infeasible without shutdown – do at next shutdown	I.2(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(e)(11)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(e)(12)	Difficult to inspect		
(e)(13)	Records	I.5(a)	Records

The related recommended rule changes throughout the CTG model rule to refer to the analogous sections of Section I rather than Section D.2 are provided in section 16.5.

16.4 The Requirements Do Not Need To Address Covers On Uncontrolled Storage Vessels And Covers And Closed Vent Systems On Storage Vessels Subject To Legally And Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under the CTG model rule.

Under the draft model rule scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

16.5 Recommended Changes To NSPS Subpart OOOOa Related To Closed Vent System And Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout the CTG model rule refer to the fugitive monitoring and repair requirements in Section I rather than the cover and closed vent system requirements in Section D. Following are the specific suggested regulatory changes.

I.1 (f) ~~For fugitive emissions components also subject to the repair provisions of sections D.2(e)(9) through (12) and (f)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers. You must comply with the requirements of paragraphs (f)(1) and (2) of this section.~~

A.3(e) You conduct the initial cover and closed vent system inspections required in section ~~D.2 I~~ within 180 days after the effective date of this rule as established by your regulatory authority.

A.5(a)

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and section ~~D.2 I.5(a)~~, as applicable.

(6) Records of each closed vent system inspection required under section ~~D.2(a) and (b)I~~.

(7) A record of each cover inspection required under section ~~D.2(e)I~~.

(8) If you are subject to the bypass requirements of ~~section D.2(d)D.1(b)(3)~~, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

C.4(a)(4) You conduct the initial cover and closed vent system inspections required in section ~~D.2I~~ within 180 days after the effective date specified by your regulatory authority.

C.6(a)(1)

- (iii) Records of each closed vent system inspection required under section ~~D.2(a) and (b)~~**I**.
- (iv) A record of each cover inspection required under section ~~D.2(e)~~**I**.
- (v) If you are subject to the bypass requirements of section ~~D.2(d)~~**D.1(b)(3)**, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.
- (vi) If you are subject to the closed vent system no detectable emissions requirements of section ~~D.2(a) and (b)~~**I**, a record of the monitoring in accordance with section ~~D.2(e)~~**I.5(a)**.

17.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

17.1 General

The following section addresses comments on EPA's proposed requirements for fugitive component emissions. Comments are organized around the following topics:

- Applicability
- Impacts, Emissions and Costs
- Work Practices and Inspections
- Testing and Monitoring
- Reporting and Recordkeeping.

17.2 Applicability

17.2.1 The Definition Of Fugitives Emissions Component Is Confusing, Which Leads To Duplicative Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 17.2.11).

The definition is also not consistent with the TSD for the rulemaking (Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities, Background Technical Support Document for the Proposed New Source Performance Standards. 40 CFR Part 60, subpart OOOOa, August, 2015). The TSD cites the white paper for the monitoring methods evaluated (Section 5.1 on page 47) and does not include blowdown lines in the description of "potential sources of fugitive emissions", but includes them in the definition of "fugitive emissions component". The white paper clearly states that emissions from blowdown lines/vents are "considered to be vented emissions and not leaks" for the purposes of the paper (page 13).

Furthermore, the types of fugitive emissions components that EPA has proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS Subparts VVa, KKK, and GGGa. Subpart VVa

defines Equipment as “each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart” (§60.481a). Under Subpart KKK, EPA defined Equipment as “each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart” (§60.631). GGGa defines Equipment as “each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment” (§60.591a).

Since these CTGs includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 12.0. Other equipment inappropriately included in this definition includes:

“access doors, ..., thief hatches or other openings on storage vessel, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters.”

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches, which are part of closed vent systems, have complexities of operation and design, as discussed in section 16.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring under Section I of the model rule.

Vents are not fugitive components because they are designed to vent. Compressors are covered in their own section of this rule. Instruments and meters are not defined and some are designed to vent.

The following section in the definition also needs to be deleted as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

~~*“Devices that vent as part of normal operations, such as natural gas driven pneumatic controllers or natural gas driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.”*~~

With the section above in the definition, devices described are not fugitive components if it is not leaking as described. But if it is leaking, it is a fugitive component. Since it cannot be known ahead of time if it is leaking as described, there is no monitoring requirement because it is not a fugitive component until it is determined that it is leaking. These equipment types are not fugitive components, and other directed maintenance programs ensure that this equipment operates as designed.

API's requested revisions to the definition of Fugitive Emissions Component are provided at the end of this section (see Section 0).

17.2.2 States Should Have The Ability To Utilize Existing LDAR Regulations In Their SIPs Rather Than The EPA Model Rule

EPA did not consider the inconsistencies with state LDAR programs (CO, PA, WY, TX, CA, etc.). This creates duplicative and potentially conflicting requirements with no little environmental benefit. If a state has a leak program in place, the CTG should not impact or disrupt the existing state program. If the EPA has approved a SIP, then the state should be allowed to utilize their existing LDAR regulations rather than following the EPA CTG model rule since the EPA has already approved of the state's LDAR program as part of the SIP. This would eliminate duplicity and redundancy in the state and federal rules.

17.2.3 The 15 BOE Exemption In I.1(a) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 boe/day. This exemption might only be useful in the rare event of a modification to a stripper well.

API believes it more appropriate and would prefer that the CTG be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment.

API would prefer that the rule be based on the equipment located at the site rather than some arbitrary production rate. As indicated in Section 17.2.7, API believes that sites with equipment configurations or component counts less than the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

17.2.4 The 15 BOE Exemption Is Not The Only Exemption To Consider

The 15 BOE/day exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions. However, it would be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should also be another threshold to exempt well sites from leak detection. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions.

Text change recommendation to reflect these comments are provided in Section 0.

17.2.5 The Definition Of Well Site For Fugitives Is Problematic And A New Definition For "Central Production Site" Is Needed

EPA has expanded the definition of a well site to include tank batteries not at a well site, as follows:

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements. (CTG I-8)

The proposed definition of "well site" includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The practical result of this error is that EPA's proposed definition of "well site" dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. API's recommended definition is provided in Section 0.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements. While the previous paragraphs discussed the issues with the definition of a "well site", a new definition is needed to more accurately account for

centralized sites. API recommends the terms “central production site” and “transmission compressor station” replace the use of the single term “compressor station”. A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of this section.

17.2.6 EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of “well site” and “fugitive emission component” could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 17.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

17.2.7 Only Sites With Major Equipment (Such As Separator, Heater, Or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

“For the purposes of this guideline, fugitive emissions recommendations would not apply to well sites that only contain wellheads.” (CTG 9.1)

API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome, with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the Technical Support Document (TSD) for NSPS Subpart OOOOa are based on the following assumed equipment and component counts.

Table 17-1 EPA Model Well Site Equipment and Compressor Counts

	<i>Assumed Equipment Counts</i>		<i>Assumed Component Counts</i>	
Gas Well Sites	Wellheads	2	Valves	114
	Separators	2	Connectors	414
	In-line Heaters	1	OELs	14
	Dehydrators	1	PRVs	6
Oil Well Sites	Oil Wellheads	2	Valves	29
	Separators	1	Connectors	104
	Headers	1	OELs	1
	Heater/Treaters	1	PRVs	1

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. It is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

There is a related inconsistency in the CTG text. Section 9.1 (Applicability) says that “for the purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site ... and compressor stations in the production segment”. However, Section 9.4 (Recommended RACT Level of Control) refers to “RACT for the collection of fugitive emission components at well sites ... and gathering and boosting stations”.

17.2.8 Based On EPA's Estimates, LDAR Requirements For Oil Well Sites Are Not Cost Effective. Therefore, Oil Wells Should Be Exempt From The CTG LDAR Requirements

Similar to the proposed low producing well site exemption for fugitives, oil well sites should be exempt from the LDAR requirements as discussed earlier (Section 2.2). This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

17.2.9 EPA Should Establish An Applicability Criteria Based On VOC Content Of The Gas Stream.

Unlike other equipment leak regulations, EPA neglected to include any kind of de minimis threshold concentration for VOC. For the CTG, since it is only related to VOC reduction guidance, it should provide a VOC threshold for LDAR as it does for tanks. API believes that the cost effectiveness calculation (see section 2.7 & 8) supports a VOC Threshold of 7% VOC by weight. API does not believe that even the 1% threshold used in the 1983 fugitive monitoring CTG for Natural Gas Processing Plants is supportable.

17.2.10 Components At Enhanced Oil Recovery Fields Must Be Exempted From The Fugitive Emissions Standards In Subpart OOOOa

Background on Enhance Oil Recovery

Crude oil development and production in U.S. oil reservoirs can include up to three distinct phases of recovery: primary, secondary, and tertiary recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. Secondary and tertiary recovery techniques, which are often referred to as Enhanced Oil Recovery, or EOR, extend a field's productive life generally by injecting water, gas, heat, or chemicals to displace oil and drive it to a production wellbore.

Examples of secondary EOR techniques includes water floods, and tertiary EOR techniques includes thermal recovery floods (e.g., steam), and gas injection floods (e.g., CO₂). These EOR oil recovery techniques are used in oil fields to improve oil recovery after reservoir gas has been produced, and reservoir pressure and primary oil production are very low (e.g., no reservoir energy). In addition, the reservoir gas is artificially or mechanically changed with inert gases. Inert gases include nitrogen, hydrogen sulfide (H₂S), and CO₂. These inert gases may be required to be gathered and process through specialty gas plants prior to sale. EOR is commonly found in older oil fields.

Water flooding is used to increase oil production by injecting a substantial amount of water into the oil reservoir rock voidage and increasing reservoir pressure. The injected water displaces the oil and carries the fluids to production wells. Water to oil ratios can be greater than 90%. In some EOR water floods, H₂S and other inert gases are generated in the reservoir. As a result, surface production equipment (i.e., plant) must be designed to handle high volumes of water and 3-phase fluids, and contain the potential "sour" and inert/contaminated gases for personnel safety reasons.

Thermal flooding is used to improve heavy oil recovery by injecting steam into the oil reservoir. Heavy oil has low viscosity, gas to oil ratio (GOR), and typically an API Gravity <18. The steam increases the heavy oil temperature reducing the viscosity allowing the oil to be produced from the well via artificial lift. The thermal surface equipment is designed to manage high volumes of water, heat the water, inject the steam, produce the hot oil, generally 2-phase separation of the fluids, and contain the low volumes of potential "sour" and contaminated gases for personnel safety reasons. Steam floods can generate substantial concentrations of hydrogen sulfide.

Gas injection (CO₂) flooding is used to improve oil recovery by injecting a miscible gas and water into the oil reservoir. The miscible gas, water, and increased reservoir pressure improves oil recovery and fluid sweep. Gas and water are injected into wells and the oil, water, and contaminated inert gas is recovered from production wells. The surface equipment is designed to manage high volumes of water, high pressure gas (e.g., CO₂ as a liquid), injection system, production/gathering system for the multi-phase liquids, high and low pressure separation of the fluids, and greater than 30% inert and potential "sour" gases. Due to the displacement characteristics of CO₂ and Immediately Dangerous to Life or Health (IDLH) for H₂S, the surface equipment is designed for personnel and public safety reasons.

EOR Gas Gathering Systems and Plants are designed to transport and process the volumes and EOR recovered gases that include CO₂, nitrogen (N₂) and H₂S.

EPA Did Not Consider EOR Operations

Oil production fields that utilize EOR have very different gas stream compositions and characteristics from the types of operations that EPA evaluated in the development of the proposed NSPS Subpart OOOOa and the CTGs. These differences have a significant impact on the VOC emissions. EPA's model plants and representative gas compositions used to evaluate the impacts that drove the regulatory decisions are derived from natural gas fields and natural gas processing plants, and these operations do not represent EOR operations. For example, EPA used a single nationwide gas composition to estimate fugitive emissions from all sources.³⁶ This gas composition includes 3.2% inerts by volume. In the limited time available during the public comment period, API did a very brief survey of member companies and found that the inert content of the gas streams in EOR fields ranged from 14% to over 64% by volume, depending on the type of EOR technique used. Obviously this significant difference in gas composition will have a tremendous impact on the baseline VOC and methane emissions and the emission reductions achieved by the fugitive emission requirements. And without a doubt, the decisions made by EPA regarding the reasonableness of the cost in relation to the VOC and methane emission reductions would not be applicable to EOR fields.

From a careful review of the background information for proposed NSPS Subpart OOOOa after which the CTGs are modeled, it appears that EPA did not consider EOR fields in any manner. A search of the September 18, 2015 preamble, the Background Technical Support Document, and the Regulatory Impact Assessment did not find a single mention of "enhanced oil recovery."

However, while EPA did not consider EOR operations in this rulemaking, clearly they are aware of these operations and the emissions. Subpart W of the GHG reporting program requires the reporting of GHG emissions from EOR operations and defines *enhanced oil recovery as follows*:

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Further, subpart W requires reporting of GHG emissions from two specific EOR operations - EOR injection pump blowdown and EOR hydrocarbon liquids dissolved CO₂. Note that in both instances EPA only requires the reporting of CO₂, indicating EPA's expectation that little or no methane would be emitted. Therefore, not only was EPA aware of these EOR operations, EPA had available GHG data from the GHG reporting program that they could have utilized. But they chose to totally ignore this segment in the industry in all technical evaluations.

Conclusions and Recommendation

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.

³⁶ Memorandum. Brown, Heather P, EC/R Incorporated to Moore, Bruce, EPA/OAQPS/SPPD. Composition of Natural Gas for use in the Oil and Gas Sector Rulemaking. July 28, 2011.

- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for Subpart OOOOa and the CTGs.
- These differences will have a significant impact on the VOC baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the CTGs or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in the CTGs. Recommended CTG changes are provided in Section 0.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in the CTGs without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

17.2.11 Produced Water Injection Facilities Should be Exempt from the Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reasons these facilities should not be included in the fugitive monitoring program:

- They contain operations and activities associated with produced water delivery, storage, and injection.
- These facilities are constructed to manage a producing field's water production.
- Natural gas is not typically associated with these facilities.
- There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled.
- Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 17.2.12.

17.2.12 Recommended Text And Definition Changes Based On Comments In This Section*I.1 Applicability*

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day.

(1) The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads.

(2) The fugitive emissions requirements of this section do not apply to any well site or process unit with a GOR less than 300.

(3) The fugitive emissions requirements of this section do not apply to any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system.

(4) The fugitive emissions requirements of this section do not apply to a well site with one or more wellheads that does not include installation of at least one of the following: a separator, heater, or glycol dehydrator.

(6) The fugitive emissions requirements of this section do not apply to a well site that produces oil with either an API gravity less than 18° or a GOR less than 300 scf.

(7) The fugitive emissions requirements of this section do not apply to an EOR.

(8) The fugitive emissions requirements of this section do not apply to a water injection well.

(b) The collection of fugitive emission components at a central production site or a transmission compressor station ~~located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.~~

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas driven pneumatic controllers or natural gas driven pumps, are not fugitive emissions components, insofar~~

~~as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

~~Well site means one or more contiguous surface sites that are constructed for directly disturbed during the drilling and subsequent operation of an oil or natural gas well, and any, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well. and its associated well site. For the purposes of the fugitive emissions standards at section I.1, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water condensate from wells not located at the well site (e.g., centralized tank batteries). For the purposes of the fugitive emission requirements, a well site that only contains one or more wellheads is not subject to these requirements.~~

17.3 Impacts, Emissions, and Costs

17.3.1 EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.

In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- Conducting leak surveys
- Completing repairs, and
- Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- Training of personnel
- Travel time and costs
- Equipment maintenance (e.g. monitoring device calibration)

The following sections expand on each of these topics in more detail and API provides revised costs that are more representative of actual costs anticipated to comply with the proposed rule. Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of \$2,230 per well site to over \$6,400 per site. As such, the Well Site Program Weighted Average cost effectiveness values (under a Multi-pollutant Method) would increase significantly beyond the already marginal value of \$4,979 per ton of VOC.

When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC. This finding is based solely on corrected costs and does not reflect any changes to the assumed emission reductions, which API believes have been overstated as well.

At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources.

The exception to this is oil wells. As discussed above in section 17.2.8 there is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

17.3.2 EPA Underestimated The Costs Of The Leak Survey And Leak Repairs In The Cost-Effectiveness Evaluation.

In the cost estimation for implementing the LDAR requirements, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site (\$600/single well battery³⁷) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site (\$600/single well battery) and lower than the value provided for a multiple well site (\$1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of \$720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

17.3.3 Many Additional Aspects Beyond The Cost Of The Actual Survey Not Considered By EPA Should Be Included In Cost-Effectiveness Evaluation (E.G., Training, Monitoring Device Calibration, Travel Costs, Etc.)

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey, such as program design and set up. EPA's cost analysis also failed to consider costs associated with training, monitoring device calibration, data management, and transportation. These are significant costs and should be part of EPA's assessment of the costs of the proposed requirements.

API surveyed companies conducting voluntary LDAR programs and compared these costs to EPA's model well site costs for annual LDAR. EPA's well pad model plant costs for semi-annual OGI LDAR surveys. Using EPA's cost spreadsheet for OGI well pad costs posted to the docket,³⁸ API added or updated costs based on company information. API's cost estimate used the same assumptions as EPA's where company data were not available. Key differences in the costs include the following:

- EPA included the cost of a M21 monitoring device (\$10,800), but excluded the cost of the data collection system. EPA's separate cost estimate for conducting M21 LDAR includes a cost of \$14,500 for a data system in conjunction with the M21 monitoring device. It is not clear why EPA excluded this cost from the OGI LDAR estimate. EPA's estimate for developing monitoring plans does not indicate if it is

³⁷ Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.

³⁸ CTG_Section_9_OGI_Well_Pad_Model_Plant_Costs_7-7--2015.xlsx

for the corporate level plan, site level plans, or both. EPA's estimate is approximately one-half the cost provided by companies with voluntary programs.

- EPA's estimate of recordkeeping costs does not account for the need to purchase or expand a data collection system to store all the information associated with an ongoing LDAR program. EPA also does not consider the need for a data analyst to manage the information.
- EPA's costs do not consider the purchase of OGI equipment (~\$100,000 per unit), annual calibration of each OGI unit, or the training required to operate each unit.
- EPA's costs do not consider travel to and from each site to conduct the semi-annual surveys and for additional travel to repair and resurvey components when the repair cannot be completed immediately following the survey.
- EPA assumed a cost of \$2.00 to resurvey repaired components. This cost implies the use of soap bubbles under Section 8.3.3 of M21 to determine if the leak has been repaired. However, as written under §60.5397a (j)(2)(ii)(A), the proposed rule does not specify that soap bubbles can be used to determine if a leak is repaired [§60.5397a (j)(2)(ii)(A) - A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.]. API's cost estimate for resurveying to determine if a leak is repaired is based on determining if the concentration is less than 500 ppm above background.

The following table compares cost information for semi-annual LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs (\$1,590 based on API estimates compared to \$2,096 from EPA's estimate shown in Table 17-2 Corrected Estimate of Monitoring Costs). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is more than twice EPA's estimate.

Table 17-2 Corrected Estimate of Monitoring Costs

Item	API Annual Total Cost (\$)	EPA Annual Cost (\$)	Comment
One-Time Company Level Costs			
Read rule and instructions	\$231.20	\$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	\$7,200.00	\$3,468.00	API members estimate \$7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	\$1,849.60	\$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	\$1,271.60	\$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	\$95,000	Excluded from EPA's analysis	API survey responses ranged from \$90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	\$225,000.00		API survey responses ranged from \$200K-250K

Item	API Annual Total Cost (\$)	EPA Annual Cost (\$)	Comment
FLIR certification Training	\$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	\$10,800	\$10,800	EPA estimate includes cost of M21 monitoring device (\$10,800) but excludes the cost of the data collection system (\$14,500) that was assumed for M21
<i>First Year Total Hours and Cost per Company</i>	<i>\$343,352</i>	<i>\$17,620</i>	Sum of total company costs above
<i>First Year Total Hours and Cost per Well Site</i>	<i>\$15,607</i>	<i>\$801</i>	Assumes company owns 22 well sites

Table 17-3 Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost (\$/yr)	EPA Annual Cost (\$/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	\$2,000.00	Not included	API estimates for annual training ranged from \$1,000 to \$5,000. Conservatively assumed \$2,000/yr
Data Analyst	\$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	\$4,000.00	Not included	API estimates ranged from \$3,000 - \$5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	\$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
<i>Recurring Annual Costs per Company</i>	<i>\$50,000.00</i>	<i>Not Included</i>	Sum of recurring annual costs above
<i>Recurring Annual Costs per Well Site</i>	<i>\$2,272.73</i>	<i>Not Included</i>	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	\$63.05	\$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	\$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	\$462.40	\$1,200.00	EPA cost from CL Report (outside contractor, well pad, \$600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.

Item	API Annual Total Cost (\$/yr)	EPA Annual Cost (\$/yr)	Comment
Repair Cost	\$597.48	\$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours * \$66.24/hr) and 1 fixed offline (1 * 4.0 hours * \$66.24/hr)
M21 Resurvey Costs	\$115.60	\$4.00	EPA's resurvey costs assume cost of \$2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	\$231.20	\$231.20	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
<i>Cost per Well Site (Well site level costs only)</i>	<i>\$1,590</i>	<i>\$2,096</i>	Sum of well site level annual costs
<i>Annual Cost per well site with Amortized Capital Cost</i>	<i>\$6,476</i>	<i>\$2,230</i>	Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest

17.3.4 EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

Section 9.4 of the draft CTG discusses the burden on the operators from the need to hire qualified contractors to perform the monitoring. Most API companies that have implemented voluntary LDAR programs for their upstream operations have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff, and required in many cases, more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand. EPA should provide an initial compliance period of 1 year to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training. In addition, API requests a one-year phase in be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

17.3.5 EPA Did Not Consider Impacts Of Travel To/From Sites By Trained Personnel (Costs And Environmental Impacts)

Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR. A company may have a third party contractor or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average

annual transportation cost per basin is \$34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of \$20,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

17.3.6 Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed model rule requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is \$188,125 with a recurring average annual cost of \$39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at \$60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin. These costs were not included in EPA's evaluation of cost effectiveness.

17.3.7 EPA Significantly Underestimated The Costs Of Developing And Maintaining The Corporate And Site-Specific Monitoring Plans

CTG I.2 and I.5 list the reporting, and recordkeeping requirements. Section I.2 describes companies developing both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements.

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plans, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of \$3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

API member companies estimate the cost for developing a corporate monitoring plan to be \$7,200, and the cost to develop each site-specific monitoring plans to be \$120. Annual recurring costs to keep the plans up to date are estimated to range from \$1,000 to \$3,000.

To count and tag components at a compressor station, costs approximately \$10,000. In a study performed by an API member company which compared three basic leak detection methods: Audio, Visual, and Olfactory (AVO), OGI, and M21. M21 was already being conducted, the additional cost of component counts was \$15 to \$58 per site. However, if done in conjunction with an OGI survey, the cost would be substantially higher. API members estimate a cost of \$120 per well site to develop an initial component count (excluding travel costs), and a recurring annual cost of \$60/site.

In addition, EPA provided no provision for an area-wide monitoring plan. Section I.2 recommends that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

- Technique for determining fugitive emissions.
- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.
- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment - Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.
- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may require a company to handle the program differently than in another part of the country where active drilling is taking place.

The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in (refer to Section 17.3.9).

17.3.8 Fugitive Emissions Program for Gross Emitters

In the preamble for proposed NSPS Subpart OOOO and OOOOa (80 FR 56637), EPA indicated that commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to “gross emitters”.

“Notably, we further identified that many studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources. Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of VOC emissions from leaks come from a minority of components. Commenters noted that emitters are likely due to random occurrences of low-probability but high-emissions conditions.” (CTG 9.4)

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources, where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates.

17.3.9 Recommended Rule Text Revisions Based On Comments In This Section.

(CTG I.2)

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site, **central production site**, and **transmission** compressor station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (e) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and control requirements in section D.

(b) You must develop corporate-wide **or area-wide** fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and compressor stations in accordance with paragraph (c) of this section, ~~and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site specific plan for each collection of fugitive emission components at a well site and each collection of fugitive emission components at a compressor station that covers the elements of both the corporate wide and site specific plans.~~

(c) Your corporate-wide ~~or area-wide~~ monitoring plan must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, as a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitives are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (e) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii).

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of $\leq 10,000$ ppm at a flow rate of ≥ 60 g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

~~(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.~~

~~(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.~~

~~(iv) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.~~

~~(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.~~

~~(B) How the operator will deal with adverse monitoring conditions, such as wind.~~

~~(C) How the operator will deal with interferences (e.g., steam).~~

~~(iii) Training and experience needed prior to performing surveys.~~

~~(iv) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.~~

~~(d) Your site specific monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(3) of this section, as a minimum.~~

~~(1) Deviations from your corporate wide plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.~~

Add to the definitions:

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

17.4 Work Practices/Inspections

17.4.1 Requiring An Initial Survey Requirement Within 30 Days Of Becoming Subject To The CTG Is Not Appropriate For A Number Of Reasons.

“(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.

(b) Each compressor station site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30 days of being subject to VOC emission control requirements of section I.2.” (CTG Appendix I.3)

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements, the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 0.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells.. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to the CTG, the central battery must be surveyed

again a month after the initial survey because of the new well. This time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of the how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 17.4.13).

17.4.2 API Members Find That Recurring LDAR Has A Diminishing Return.

EPA solicited comments on requiring monitoring survey on a quarterly basis. API members find that recurring LDAR has a diminishing return [currently proposed as semiannually]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates, ranging from 0.18% to 0.84% leaks per component for annual LDAR.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)*³⁹ shows that 5,000 ppm leaks were detected

³⁹ Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at

with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of \$5,700 per ton.** In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."

17.4.3 API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components.

EPA solicited comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

"We recommend that the monitoring frequency be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station." (CTG 9.5.1)

API does not support the proposed metrics of one percent and three percent of components, respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components.

To count and tag components at a compressor station, costs ~\$10K and requires continual ever-greening. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was \$15 to \$58 per site. However, if done in conjunction with an OGI method, the cost would be substantially higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of \$120 per well site to count

components initially, with a recurring cost of \$60 per well site to validate and update the counts annually.

17.4.4 Having The Same Frequency Of Monitoring As EPA's NSPS OOOOa Will Be Far Too Burdensome With The Large Number Of Existing Sites Which Are Almost All Unmanned, Dispersed Locations.

The draft August 2015 CTG (EPA-453/P-15-001) proposes semiannual fugitives monitoring of well sites greater than 15 boe/day and gathering/booster stations as RACT (page 9-31). The cost data presented in Table 9-11 shows a cost of \$8,069/ton of VOC reduction for annual OGI inspections, while Table 9-12 shows a cost of \$9,124/ton of VOC reduction for semi-annual OGI inspections. Despite a cost difference of \$1,055/ton of VOC reduction or only 12.3% difference, EPA proposes semiannual OGI inspections as RACT. The small cost difference (based on EPA's analysis) between annual and semi-annual inspections does not justify the semi-annual inspections.

Also, the cost data on page 9-19 of the August 2015 CTG shows an OGI contractor cost estimate of \$600 for a well site and \$2,300 for a gathering/booster station, and repair costs of \$299 for well sites and \$3,436 for gathering/booster stations assuming 1.18% of the components leak and 75% are repaired online and 25% are repaired offline. EPA estimated the cost for resurveying components after offline repair based on \$2.00 per component resurveyed and the assumption that a company purchases M21 instrumentation for \$10,800 and is able to perform the resurveying without needing contractors. EPA assumed annual reports would take one person a total of 4 hours to complete at a cost of \$231.

For comparison purposes, the costs from the Colorado Regulation 7 survey data were the following: OGI survey by contractor - \$200-400 per well site, \$1,321 for gathering/booster stations; excludes equipment rental, which is approximately \$250 per site; Repair costs - \$200 for well sites; Annual reports - \$4,370 average annual report for a company's basin (note that Regulation 7 reports are required on a basin basis).

EPA assumes companies will use a third party for monitoring at \$600 per site and does not include estimated costs for a company to buy and maintain a camera of their own (higher capital cost) or supervisory costs. In the report "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" (March 2014, Prepared for Environmental Defense Fund by ICF International) a more representative cost analysis includes the camera purchase costs as well as transportation and recordkeeping, resulting in an annual cost of \$191,000 (compared to \$4,031 in the EPA OOOOa TSD, assuming quarterly OGI inspections as presented in Table 5-19). This analysis was updated in 2014 in which the annual cost (including cost of repairs inadvertently omitted from the previous analysis) was \$193,000.

17.4.5 Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Component Counts For Each Well Site In Order To Properly Document The Percentage Of Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage.

"We recommend a monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station be conducted at least semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend that the monitoring frequency be increased to quarterly in the

event that two consecutive semiannual monitoring surveys detect fugitive emissions at 1.0 percent or more of the fugitive emissions components at a well site or at 1.0 percent or more of the fugitive emissions components at a compressor station. We also recommend that the monitoring frequency be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. We also recommend that you require that the monitoring frequency return to semiannual if an annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station.” (CTG 9.5.1)

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment, which are combined with EPA assumptions on component counts per equipment.

See Section 17.3.8 regarding API's preference for annual monitoring.

17.4.6 API Opposes Performance-Based Frequency

EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based approach. Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in the comment above, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys. API advocates a fixed annual frequency, regardless of the percent of leaking components.

17.4.7 API Suggests 30 Days An Appropriate Amount Of Time For Repair Of Sources Of Fugitive Emissions At Well Sites

EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team, when authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However a few leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Recent data from Colorado's Regulation 7 indicate that about 5% of

identified leaks required a delay of repair.⁴⁰ It is more reasonable to allow 30 days to do the repairs.

Proposed text revisions are provided in Section 17.4.13.

17.4.8 The current proposal does not allow for multiple attempts to repair identified leaks

In the proposed model rule, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak. Proposed text revisions are provided in Section 17.4.13.

17.4.9 Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Regulation 7 indicate that about 5% of identified leaks required a delay of repair.⁴¹ Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate

⁴⁰ Colorado Air Quality Control Commission, Public meeting on October 15, 2015.

⁴¹ Colorado Air Quality Control Commission, Public Meeting on October 15, 2015.

shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months and OOOOa should be less stringent than what is required under NSPS Subpart VVa. Subpart VVa under §60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair:

- §60.482-9a (a) *Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.*
- (b) *Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.*
- (c) *Delay of repair for valves and connectors will be allowed if:*
- (1) *The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and*
 - (2) *When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.*
- (d) *Delay of repair for pumps will be allowed if:*
- (1) *Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and*
 - (2) *Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.*
- (e) *Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.*

(f) *When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition."*

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Proposed text revisions are provided in Section 17.4.13.

17.4.10 Thresholds for M21 Leak Definition and Repair.

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). EPA also solicits comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA-HQ-OAR-2010-0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found-leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak threshold should be set at 10,000 ppm.

Proposed text revisions are provided in Section 17.4.13.

17.4.11 API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

"We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites and compressor stations." (CTG 9.4)

EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles.

17.4.12 Monitoring Each Fugitive Component for Emissions

CTG I.2(e) – EPA is requiring that “*Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.*” Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. . Here is an example of what the sites look like:

Figure 17-1 Picture of Equipment Building



API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components.

Proposed text revisions are provided in Section 17.4.13.

17.4.13 Recommended Text Revisions Related To Work Practices/Inspections:

I.2(e) Each monitoring survey shall observe each **piece of equipment with** fugitive emissions components **s** for fugitive emissions.

I.2(f)(1) Each identified source is required to monitor fugitive emission components as specified in section I.3 and I.4. Identified fugitive emissions shall be repaired or replaced as soon as practicable, ~~but~~ no later than **4530** calendar days after detection of the fugitive emissions. **Where delays in acquiring replacement parts prevent completion of repairs**

within 30 days, repairs must be completed within 30 days of acquiring parts. If the repair or replacement is technically infeasible or unsafe, or shutdown emissions are larger than what would be reduced to repair during operation of the unit, to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 1530 days after completion of the repair or replacement, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using M21 or optical gas imaging no later than 1530 days of finding such fugitive emissions.

(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 50010,000 ppm above background.

I.3(a) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30180 days of being subject to VOC emission control requirements of section I.

(b) Each compressor station site or central production site with a collection of fugitive emissions components must conduct an initial monitoring survey within 30180 days of being subject to VOC emission control requirements of section I.2.

(a) A monitoring survey of each collection of fugitive emissions components at a well site, a central production site, and a compressor station site subject to VOC emission control requirements under section I shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least nine four months apart.

~~(b) The monitoring frequency specified in paragraph (a) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than three percent of the fugitive emissions components at a well site or at greater than three percent of the fugitive emission components at a compressor station subject to VOC emission control requirements under section I.~~

~~(c) The monitoring frequency specified in paragraph (a) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect no fugitive emissions at less than one percent of the fugitive emissions components at the well site, or less than one percent of the fugitive emissions components at a compressor station subject to VOC emission control requirements under section I. The monitoring frequency shall return to semiannual if a annual survey detects fugitive emissions between one and three percent of the fugitive emissions components at the well site, or between one and three percent of the fugitive emissions components at the compressor station, and shall return to quarterly if a survey detects fugitive emissions at greater than three percent of the fugitive emissions components at the well site, or greater than three percent of the fugitive emissions components at the compressor station.~~

17.5 Testing And Monitoring

17.5.1 EPA Should Provide Flexibility And Allowance For Technology Development.

Ongoing Research and Development Activities

The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of M21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E)

As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totalling some \$35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify - major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired.

ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera (\$90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to \$3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as \$1,000 per site.

EDF Methane “Detectors Challenge” (MDC)

In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and natural gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot

purchases and testing at oil and natural gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and natural gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a “smart” alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The “MDC program refers to cost as a critically important factor and EDF and its partners sought out technologies that could reasonably be expected to be sold for roughly \$1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.

The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called “Phase 1.” Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as “Phase 2” which tested each technology developer’s entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations

An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as “... an instrument that makes visible emissions that may otherwise be invisible to the naked eye.” EPA’s Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)⁴² provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should allow any new technology to be used that is equivalent to OGI or M21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA’s current definition of OGI (i.e. “... an instrument that makes visible emissions that may otherwise be invisible to the naked eye.”). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

17.5.2 The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on “criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining.”

⁴² Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at <http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf>

A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).
- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H₂S concentrations where AVO is more effective than M21. Sites with high levels H₂S should be allowed to use AVO or H₂S monitoring systems to identify leaks at well pads.

17.5.3 Characterizing Performance Using Laser Technology

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since the CTGs do not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

17.5.4 A Streamlined Approval Process Is Needed For Alternative Technologies As These Technologies Become More Prevalent.

EPA should build into its final rule an “on-ramp” that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined “fast-track” process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved

for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level “equivalency” should not be required as EPA has required for using OGI versus M21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow “equivalence test for approving alternative methods. Moreover, the stringency of the process and “equivalency” testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in §60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7⁴³ provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or M21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

17.5.5 Comment On Whether To Allow EPA M21 As An Alternative To OGI For Monitoring, Including The Appropriate EPA M21 Level Repair Threshold

The draft CTG implies that the initial leak surveys must be taken using an OGI. We recommend revising the requirements to specifically state that OGI, M21, or an equivalent method may be used for both the initial survey and repair leak surveys.

In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves M21 for repair confirmation and emissions quantification is not required. According to Section 8.3.3 of M21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under M21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap

⁴³ <https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf>

bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

17.6 Reporting And Recordkeeping

17.6.1 The CTG Should Not Require A Separate Report For Each Well Site.

CTG I.5 (b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

API interprets “each collection of fugitive emissions components” to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations submit the combined reports in one annual report.

17.6.2 The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value.

CTG I.5(a)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed. Under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the CTG it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. Photos of the well site or compressor are not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

A photo of a survey being performed does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator's certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey. In addition, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate.

In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally unmanned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey.

Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. API requests that EPA remove the requirement to take a photograph.

17.6.3 API Strongly Opposes Sending Digital Photographs And Logs To The Permitting Agencies.

EPA solicited comments on whether these [digital photographs and logs] records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens API strongly opposes sending digital photographs and logs to the permitting agencies. EPA's cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there is a real security risk putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with little to no security.

17.6.4 EPA Needs To Greatly Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

“XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and
XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s)."

API requests that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

"XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:
XVII.F.9.a. The number of facilities inspected;
XVII.F.9.b. The total number of inspections;
XVII.F.9.c. The total number of leaks identified, broken out by component type;
XVII.F.9.d. The total number of leaks repaired;
XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and"

17.6.5 Proposed Text Revisions Associated With Reporting and Recordkeeping Requirements.

I.5(a) Records for each monitoring survey shall be maintained as specified in paragraphs (a)(1) through (6) and must contain, at a minimum, the information specified in paragraphs (a)(1) through (a)(6). Records are required to be maintained onsite or at the nearest local field office for at least five years.

(1) Date of the survey.

(2) Location of the survey

(3) A list of leaking components

(4) The date of the first attempt to repair and additional attempts to repair

(5) The date the leak was repaired

(6) The delay of repair list including the basis for placing leaks on the list

(7) The date the leak was remonitored to verify the effectiveness of the repair

~~(2) Beginning and end time of the survey.~~

~~(3) Name of operator(s) performing survey. You must note the training and experience of the operator.~~

~~(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(5) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(6) Documentation of each source of fugitive emissions (e.g. fugitive emissions component), including the information specified in paragraphs (a)(6)(i) through (iv) of this section.~~

~~(i) Location.~~

~~(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station subject to VOC emission control requirements under section I imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photo-graph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(iii) The date of the successful repair of the fugitive emission component.~~

~~(iv) The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

(b) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a **central production site or transmission** compressor station subject to VOC emission control requirements under section I that include the information specified in paragraph (a) of this section for each monitoring survey conducted during the year. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a **central production site or transmission** compressor station subject to VOC emission control requirements under section I may be included in a single annual report.

Attachment A

Technical Review of Western Climate Initiative Proposals to
Meter Fuel and Control Gas

**Technical Review of Western Climate Initiative Proposals to
Meter Fuel and Control Gas**

**Prepared by: David A. Simpson, P.E.
MuleShoe Engineering**

Prepared: February 16, 2010

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Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the “most accurate” volumes if the gas was metered as a “fuel” stream and a “control” stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to “provide the rigor required for either cap-and-trade or offset programs”. The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer’s numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The “Per Company” column below assumes 2,000 wells per company, “Total WCI” column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under “Cost of Implementation” below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well (\$k)	Per Company (\$million)	Total WCI (\$million)
RTU Replacement	\$3.5	\$7	\$350
Host/Database		\$15	\$750
Site Modifications	\$30.0	\$60	\$3,000
Total Capital	\$33.5	\$82	\$4,100
Annual Operating Costs	\$1.5	\$3	\$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate “accuracy” in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different “emissions factor” on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as “on demand” in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators

take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 “turndown ratio”. Turndown ratio is a measure of ability of a measurement device to provide similar “accuracy” over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from “off “ to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer’s estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since “rich” liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

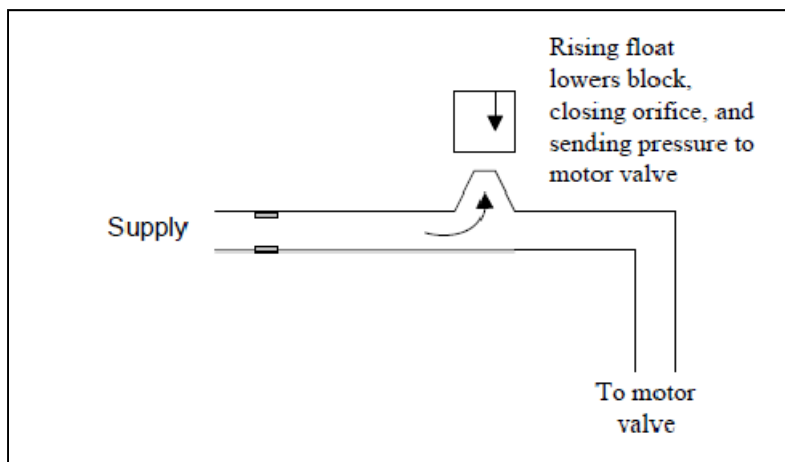
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

4. *Pneumatic devices*

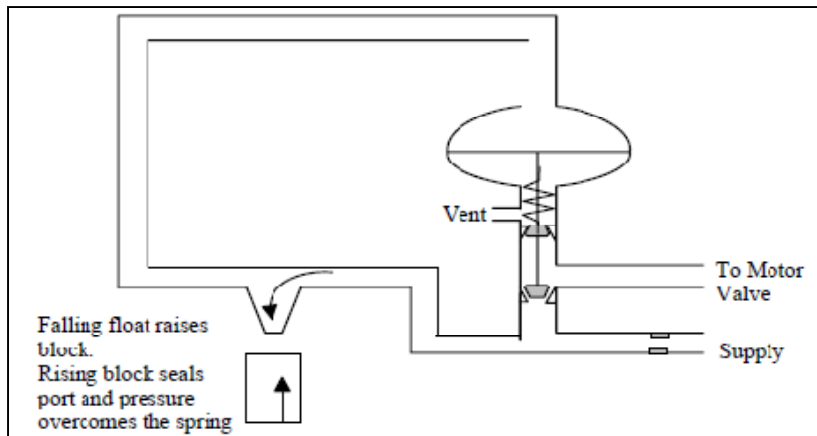
I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either “Throttling” or “Snap Acting”. Bleed characteristic is either “continuous bleed” or “no bleed”. An example of a Continuous Bleed, Throttling controller is shown below



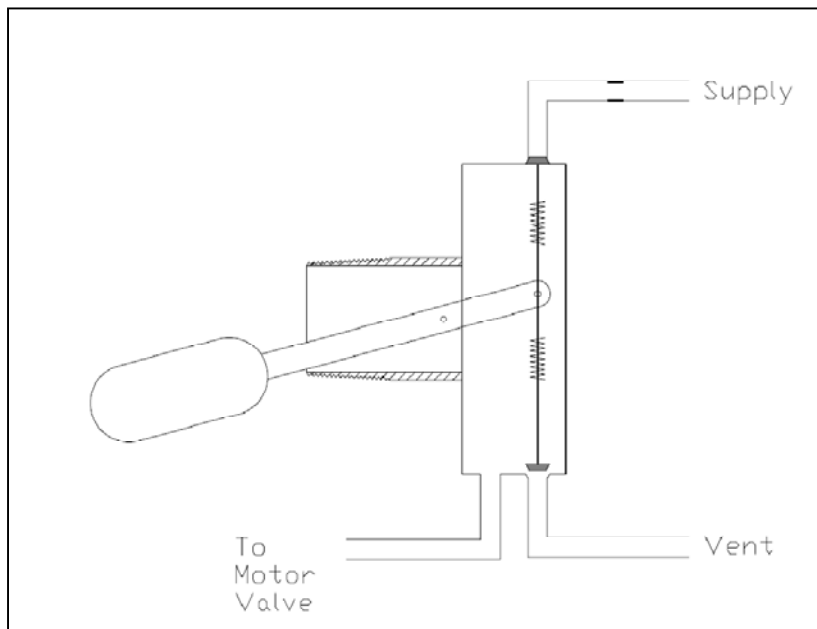
In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled

devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A “No Bleed” controller would look something like:



This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the

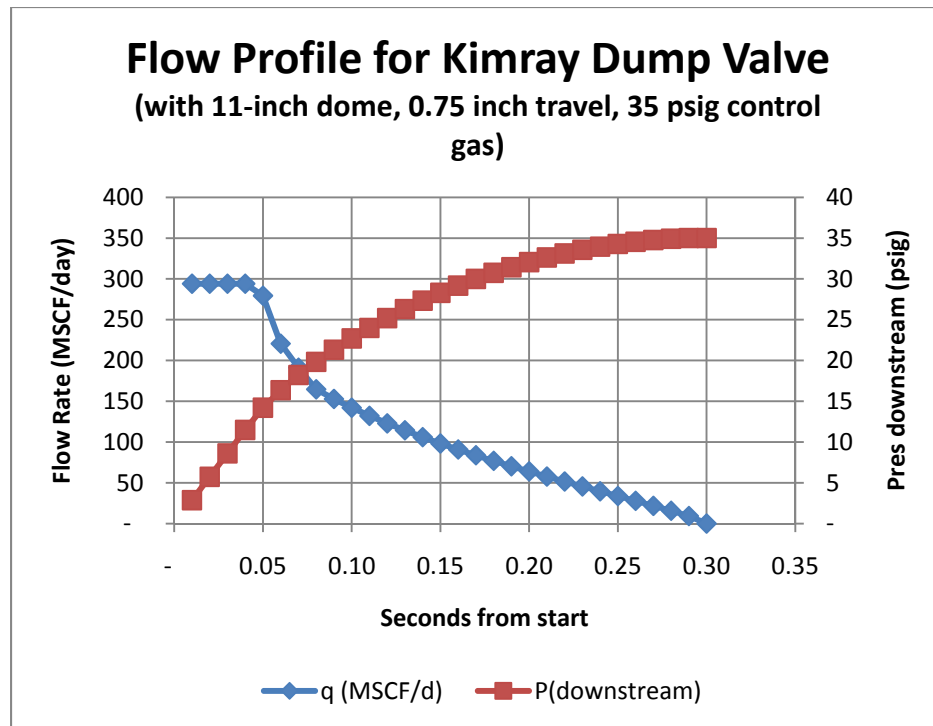
vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it “snaps” open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas is used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing “bleeding” of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can’t be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a “jerky” action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft^3) and the diaphragm dome is 0.04 ft^3 (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft^3 . At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about “meter accuracy” above I always said “accuracy”. “Accuracy” is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of “accuracy” is encompassed in the terms “repeatability” and “uncertainty” which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

“Repeatability” is a measure of a device’s ability to report the same output for a given set of inputs. Many things can impact a device’s repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable

repeatability occurs when the standard deviation of the sample data is within $\pm 0.05\%$ of the mean value.

“Uncertainty” is the “dead band” of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device’s calibrated span. For example, a digital pressure transducer may have a stated uncertainty of $\pm 0.5\%$ which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices’ uncertainty is less than $\pm 2.0\%$ (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is “latency”. Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are “inferential” technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli’s development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. *Gas Analysis*

Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed $\pm 25\%$.

These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

This device has potential, but the smallest meter (1/2" ID) would register zero during pilot flow and would have a dP less than 7 inH₂O (0.25 psi)

while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

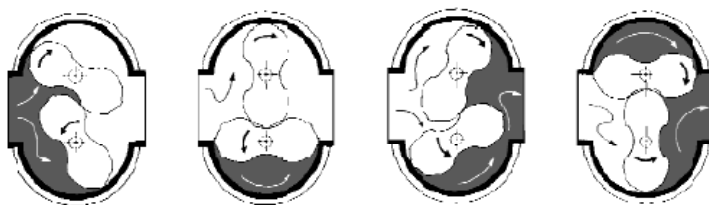
The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to “measuring” gas volumes instead of “inferring” a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. *Diaphragm Meters*

The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. “Household quality” meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H₂S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). “Industrial quality” meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or “yellow metal” is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

The volume of gas discussed in this application kept leading me to devices like “Thermal Dispersion Meters” (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

- a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.
- b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a “valve open” clock on the supply line, which (in conjunction with manufacturer’s data and Engineering analysis) would result in a better volume than attempting to meter the gas.

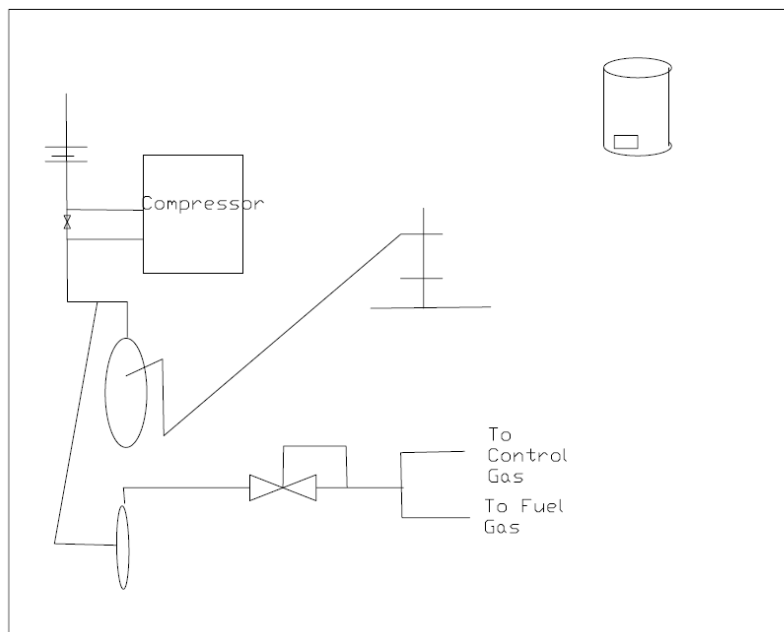
- c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Coriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.
- d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can’t be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

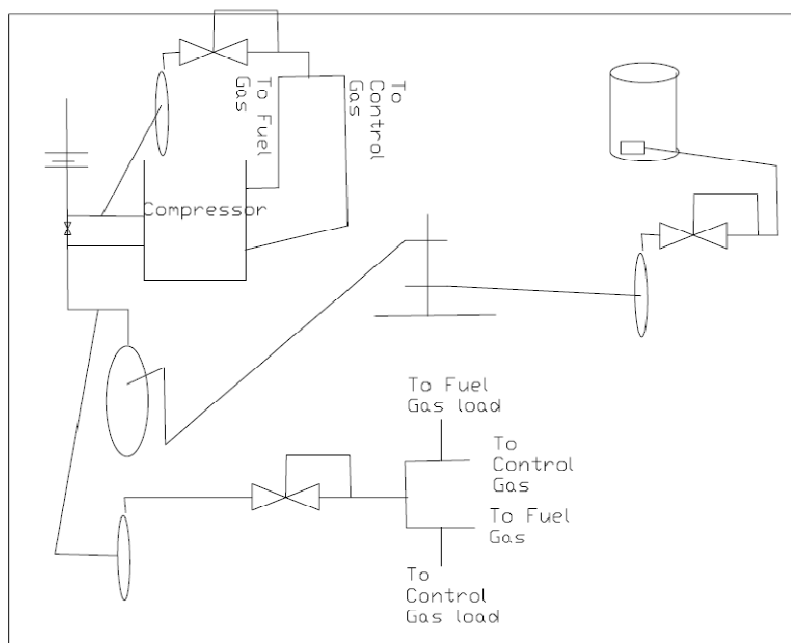
On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a “standard” wellsite where fuel-gas measurement equipment can be “relatively easily” installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since

compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a “typical” wellsite, “typical” automation system, or “typical” host/database modification because there is no such thing. There are companies within the WCI area of operation that don’t have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I’ve worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at

http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at <http://www.capp.ca/GetDoc.aspx?DocID=146286> for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I’ll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of \$4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately \$3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data polling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost \$15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend \$750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At \$1,200/day that is \$12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be \$30,000/well—100,000 wells would cost \$3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a \$5/MMBTU sales price the cost of this lost production is \$600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is \$150,000/year which works out to about \$750/meter/year or \$1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.



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December 17, 2018

The Honorable Andrew Wheeler, Acting Administrator
Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Submitted to www.regulations.gov

**Re: Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector:
Emission Standards for New, Reconstructed, and Modified Sources Reconsideration;
Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018)**

Dear Acting Administrator Wheeler:

The American Petroleum Institute ("API") is pleased to submit the attached comments regarding EPA's reconsideration of the New Source Performance Standards ("NSPS") 40 C.F.R. Part 60 Subpart OOOOa, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Proposed Rule" at 83 Fed. Reg. 52056 (October 15, 2018).

API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's 620 members include large integrated companies as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 40 million Americans. Many of our members are directly impacted by the proposed amendments to the rule.

Throughout the development of the 2012 oil and gas NSPS rule and its amendments in 2016, API has maintained a constructive working relationship with EPA staff to provide operational expertise and emissions data to inform the developments of these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions for new and modified sources and, as a co-benefit, also reduce methane emissions. Importantly, all oil and gas production emission sources that are covered by the previous 2012 and 2016 rules will continue to be effectively addressed. This approach, when combined with the leadership the industry has demonstrated to voluntarily reduce emissions from existing sources, has already proven effective in reducing emissions. Our industry has led the way in its pursuit of improved operations and keeping our product in the pipe, and the industry is incentivized to safely recover and capture methane as it is the primary component of natural gas.

Even as US oil and natural gas production has surged, methane emissions have declined significantly. For example, methane emissions from the natural gas industry have fallen 16 percent even as production increased by 50 percent since 1990. This is effectively a 45% reduction in the rate of emissions, further demonstrating industry's continued progress in minimizing emissions as we maximize efficiency in getting energy to the consumer.

Methane emissions from hydraulically-fractured natural gas well completions have fallen more than 85 percent since 1990, and the increased use of natural gas to fuel the power sector has played the most significant role in achieving 30-year lows in carbon dioxide emissions from power generation that we see today. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment while protecting our nation's energy security. We fully expect that progress will continue.

API supports EPA's reconsideration of the rule and appreciates the proposed changes that provide additional clarity for our industry to maintain compliance. However, the proposed rule includes several missed opportunities and, in many circumstances, has increased the stringency of the rules without securing additional environmental benefit. Overly burdensome recordkeeping and reporting, overlapping regulatory requirements with state leak detection and repair programs, and a reinterpretation of several important aspects of the rule are all examples where further improvement is warranted to balance compliance assurance with securing emissions reductions.

There are significant capital investments and scientific studies underway to advance the development and use of new emission detection technologies; the proposed regulation that requires site-specific approval for each new technology will only stifle this positive development. We hope that EPA continues to significantly streamline this process in the final rule. The rule also fails to reduce the burden of overlapping regulatory requirements that have no

environmental benefit. While the agency agrees that many state leak detection and repair programs are equally effective, significant and duplicative recordkeeping and reporting remain. This is just regulatory burden without environmental benefits, and we encourage the agency to improve the recordkeeping and reporting requirements in the final rule.

We also encourage the EPA to recognize the value of the field data measurements that have been shared with the agency. API collected initial leak survey data during normal operations from more than 4,000 sites and representing more than 2 million components that demonstrates a much lower incidence of leaks when compared to the EPA estimates in the rule. However, the agency has dismissed this data due to hypothetical uncertainties that effectively undermines the credible advantages the use of optical gas imaging cameras provides to our industry by facilitating our ability to find and repair leaks. These findings should inform the final rule because they support an annual frequency as a cost-effective survey frequency at well sites and, importantly, demonstrate that the agency has significantly overestimated the emissions resulting from implementation of this rule as proposed.

In API's petition for reconsideration, we sought a reduction in the administrative burden to operators by revisiting the amount of records required to be maintained and reported for each leak detection survey. The oil and gas sector is unique in that thousands of newly affected sources will, year after year, compound the recordkeeping and reporting burden. However, in the proposed amendments, EPA has *increased* the recordkeeping and reporting requirements to operators without adequately justifying increased costs with respect to the administrative burden these proposed changes would require. The level of data required for recordkeeping and reporting within subpart OOOOa unnecessarily includes significantly more data points than other traditional LDAR programs with fewer affected sources.

API and its members recognize the importance of developing oil and gas resources responsibly, but there is no value to implementing duplicative and costly regulations with little or no environmental benefit. The combined technologies of hydraulic fracturing and horizontal drilling have elevated the United States to global prominence as an energy superpower. Because of the advanced application of these technologies, the United States is now the world's largest producer of oil and natural gas while, at the same time, emissions from the industry continue to decline. This positive trend will continue as many companies engage in multiple voluntary programs and individual efforts to further reduce emissions from oil and gas production. Industry's commitment to reduce emissions is exemplified by The Environmental Partnership, a program that has brought more than 50 of the nation's oil and gas producers together, both large and small and operating across the entire nation, to take concrete actions to reduce emissions. This energy revolution has helped to energize the U.S. economy by driving domestic investment in energy projects, creating jobs, and enhancing U.S. energy and national security interests. We encourage

the agency to consider these positive trends and the important benefits this industry provides as you consider comments on the proposed rule.

Please contact me at toddm@api.org or 202-682-8319 with any additional questions regarding the content of this submittal.

Sincerely,

Matthew Todd

cc: Peter Tsirigotis, USEPA
David Cozzie, USEPA

**API Comments on Oil and Natural Gas Sector:
Emission Standards for New, Reconstructed, and
Modified Sources Reconsideration, 83 Fed. Reg.
52056 (October 15, 2018)
Docket ID: No. EPA-HQ-OAR-2017-0483**

December 17, 2018

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A – API’s Response to EPA’s Analysis of Well Site Fugitive Emissions Monitoring Data

B – API Analysis of Subpart OOOOa Semi-Annual Leak Survey Data

C – Production Flows and Operating Pressure

D – Sample Observation Narrative

**API's Comments on Oil and Natural Gas Sector: Emission Standards for
New, Reconstructed, and Modified Sources Reconsideration
Docket ID No. EPA-HQ-OAR-2017-0483**

1.0 FUGITIVE EMISSIONS AT WELL SITES

1.1 ANNUAL LEAK SURVEY FREQUENCY FOR WELL SITES IS APPROPRIATE

API supports EPA's proposed revision to Subpart OOOOa to establish an annual frequency for leak surveys at new and modified well sites. An annual survey frequency is appropriate for the following reasons:

- EPA has mischaracterized the assumed number of leaking components per well site in their supporting document, citing 1.18% of components leaking (4 components per site) when the underlying emission factors used to estimate overall emissions assume higher leak rates.
- Data from API members surveys conducted under Subpart OOOOa as well as under state and voluntary programs show the average well site has significantly fewer leaking components than EPA assumed in its rulemaking; and thus, much lower baseline emissions prior to implementation of leak requirements.
- Given the much lower rate of leaks being found at well sites, during initial and subsequent leak surveys, there are limited environmental benefits to conducting leak surveys for well sites more often than annually.
- If EPA uses the best available data – data from the large number of surveys completed over the last few years – and reevaluates the benefits and costs from the Subpart OOOOa leak requirements, it will determine that there are less baseline fugitive emissions and, as a result, semi-annual leak surveys are not cost effective for well sites.

API members have been conducting leak surveys for new and modified well sites under Subpart OOOOa since the rule was effective in June 2017. Additionally, members have been conducting surveys under state and voluntary programs for much longer. These data, as well as data from other recent studies^{1,2} indicate that the average facility has very few leaking components, even during the first leak survey.

¹ Lyon, et al. 2016. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites" (<https://pubs.acs.org/doi/pdf/10.1021/acs.est.6b00705>) – Aerial OGI surveys of 8220 well pads in seven basins identified 494 unique emissions sources at 327 well pads (< 4% of sites).

² "Lowering Emissions Across the Piceance," 2018 presentation by HRL Compliance Solutions and Colorado Oil and Gas Association – West Slope. Approximately 42,000 surveys at 2,200 sites found that 94.3% of leak surveys found no (0) leaks.

1.1.1 INDUSTRY DATA SHOWS THE NUMBER OF LEAKS IS LESS THAN THOSE ESTIMATED BY EPA

API previously initiated a data collection and analysis effort from member companies to determine how the implementation of leak monitoring and repair programs might further inform a reduced leak survey frequency. These data were provided to EPA in February 2018 and represented a range of operators across a range of geographies. The data represented observations from over 4,000 well sites, as compared to the 24 oil and gas sites upon which the emission factors in Table 2-4 of the 1995 Protocol for Equipment Leak Emission Estimates (EPA Leak Protocol) (EPA-453/R-95-017) are based. In response to this submittal, EPA provided a summary of its review of the data as part of the docket for this proposal (Docket EPA-HQ-OAR-2017-0483-0036). EPA did not objectively critique the submitted data. Rather than looking at the totality of the data and trends shown, EPA raised questions that could only be answered by a controlled experiment. API is including comments in response to EPA's analysis of the data as Attachment A of this document.

As a follow-up to the data analysis that API provided to EPA in early 2018, API undertook a recent effort to collect Subpart OOOOa data from member companies to understand how data collected under the rule might differ from the broader dataset previously provided to EPA. The reported Subpart OOOOa data include data from both the initial and second annual reporting period and show trends that are entirely consistent with API's earlier dataset and analysis. Specifically, the Subpart OOOOa data show:

- There are large number of sites that have no leaks (58% of initial well site surveys).
- The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. These values are both below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions (See Figure 1 in Comment 1.1.3). In fact, nearly 92% of all surveys conducted across the 2 year period identified 4 or less leaking components per site.

Summary data and analysis of the Subpart OOOOa data from member companies is provided in Attachment B. While EPA previously expressed prior concern about certain aspects of the previous API survey data, API expects that providing these data developed from Subpart OOOOa surveys should adequately address any EPA concerns. The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA's proposed annual survey frequency. API welcomes the opportunity to discuss these data further with EPA.

1.1.2 SUBPART OOOOa BASELINE FUGITIVE EMISSIONS ARE NOT BASED ON 1.18% OF LEAKING COMPONENTS AT THE MODEL PLANT

At the time of the original Subpart OOOOa rulemaking, EPA did not have adequate leak detection and repair data from well sites and compressor stations to develop baseline emission rates. Therefore, EPA relied upon the general oil and gas leak emission factors from the EPA Leak Protocol. Specifically, EPA

applied emission factors in Table 2-4³ to all components estimated within the model plant in order to quantify the baseline emissions in absence of a leak detection and repair program.

The above point is important because EPA and others have often cited that the Agency assumed a leak incidence rate of 1.18% for fugitive components in the analyses to support the development of Subpart OOOOa. EPA discusses this issue extensively in the preamble for the current proposed rulemaking (Section B.1). However, this statement is inaccurate with respect to the emission rates that EPA assumes in the rulemaking to estimate baseline emissions. EPA assumes 1.18% of components at the model plant are leaking with respect to the count of components that require repair. However, this value does not have any bearing on the baseline emissions nor quantified benefits from implementing leak detection and repair (LDAR) at well sites over time.

The figures in Chapter 5 of the EPA Leak Protocol can be used to determine the fraction of different component types that are assumed to be leaking, when applying the Table 2-4 factors to represent a population of components. This is demonstrated in Figures 5-16 through 5-34 of the EPA Leak Protocol. Each component type (connectors, flanges, open-ended lines, etc.) and each service have a different assumed leak fraction (or assumed number of leaking components) embedded within the average emission rate listed in Table 2-4. (See Attachment A of these comments for further discussion of an example figure from Chapter 5 of the EPA Leak Protocol.)

Using the figures and correlation equations within the EPA Leak Protocol, one can calculate that, for the EPA model facility used in the 2016 Subpart OOOOa rulemaking, EPA actually assumed between 1.6% and 2.5% of components at a model well site were leaking, depending on the leak threshold used to define the leak. The lower value represented an assumed 10,000 ppm Method 21 leak definition, and the higher value assumed a 500 ppm leak definition, which is the leak definition finalized within Subpart OOOOa.

We also note that the analysis EPA has done in the 2018 Subpart OOOOa proposal for pressure relief devices (PRDs) on controlled storage vessels follows a similar process to arrive at new emission factors based on newly available data. Similar to the Table 2-4 factors, the proposed emission factor represents yet another assumed fraction of components to be leaking for a particular component type that differs from the 1.18% value EPA cites.

1.1.3 EPA'S ANALYSIS OVERESTIMATES BASELINE WELL SITE EMISSIONS AND EMISSION REDUCTIONS FROM LDAR

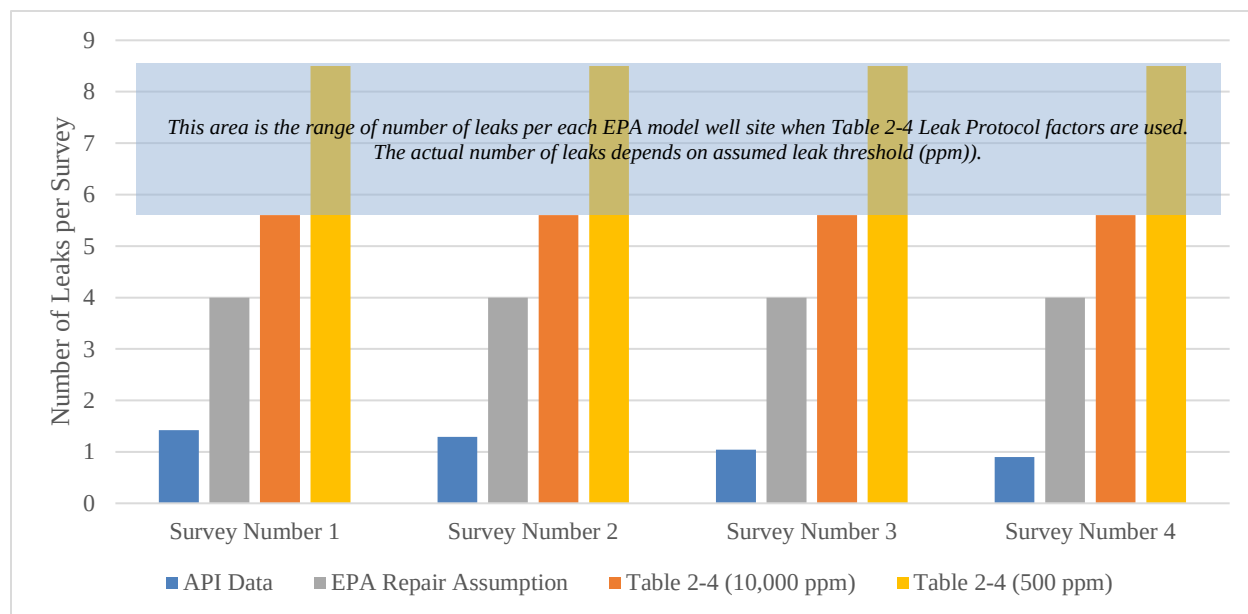
In addition to EPA relying upon the Leak Protocol emission factors that assume a higher percentage of components to be leaking than EPA's stated 1.18%, data from leak surveys conducted at regulated facilities indicate even fewer components are actually leaking. Figure 1 below illustrates the relative magnitude of the over-estimation. This figure was developed by normalizing the following data on a number of leaks per well site basis with the following assumptions:

³ The emission factors developed in Table 2-4 are based upon analysis of leak data from a limited number of facilities using Method 21. Specifically, the protocol is based on only a total of 24 oil and gas sites, as noted on page C-14 of the EPA Leak Protocol.

- Scaled EPA's 1.18% (or 4 leaking component) assumption to the percentage range (1.6% to 2.5%) behind the EPA Leak Protocol Table 2-4 values to estimate the average number of components expected to be leaking.
- Plotted data from API member company Subpart OOOOa surveys showing actual numbers of leaks found during semi-annual surveys.

It is clear that EPA's assumed number of leaking components, and by direct extension, the estimated amount of fugitive emissions are significant overestimates – by a factor of over 2.5 to up to 4 times.

Figure 1. Comparison of Actual Leaks Observed under Subpart OOOOa vs. EPA Model Plant Data Assumptions



1.1.4 LIMITED FORGONE EMISSIONS IMPACT

As part of the proposed rulemaking, EPA estimated the forgone emission reductions associated with impacts of the proposed changes, if finalized. The only forgone emission reductions from this proposal are expected to be from semi-annual leak surveys moving to annual leak surveys. Even with EPA's overestimation of emissions from fugitives and, thus an overestimate of benefits from implementing LDAR requirement, the following benefits are still realized:

- *Relative to only reductions from Subpart OOOOa leak provisions* – EPA estimates indicate that approximately 77-78% of LDAR reductions relative to the benefits from the 2016 Subpart OOOOa rule provisions will still be realized after accounting for state rules that are providing Subpart OOOOa like LDAR benefits (OH, PA, CA, CO, WY in EPA's analysis).
- *Relative to Reductions from all rule provisions* – EPA estimates indicate that approximately 85-87% of the reductions relative to the 2016 Subpart rule will still be realized after accounting for state rules that are providing Subpart OOOOa-like LDAR benefits.

The above statements are important as there are many who are referring to this proposed rulemaking as a major regulatory rollback or action that will result in significant emissions increases. This is inaccurate even with EPA's overestimates. When one accounts for the lower actual mass of reductions that are occurring through implementation of the leak provision, the amount of forgone benefits are even lower.

1.2 LOW PRODUCTION WELL SITES

API endorses the more detailed comments of IPAA and provides the following additional comments.

1. EPA should exempt low production well sites as originally proposed in 2015. As API has stated in prior comments, low production well sites typically have less equipment located on the well site and, therefore, less sources that could result in fugitive emissions. Given that there are no comprehensive studies indicate that low production well sites would have a higher fraction of components leaking than other well sites, it is expected that low production well sites, on average, will have lower emissions than other well sites. The IPAA comments further discuss the issues associated with EPA's reliance on data from a Barnett Shale study to represent low production wells in the Subpart OOOOa rulemaking process.
2. Furthermore, while the production rate does not directly impact the number of fugitive emissions from a site, it can be an appropriate surrogate for correlation in this context. Low production well sites typically operate at reduced operating pressures (i.e., often less than 100 psig) when compared to average production sites.
3. All well sites will eventually become low production well sites. Therefore, Subpart OOOOa affected well sites that become low production well sites should have a pathway to cease or reduce monitoring frequency following 12 consecutive months demonstrating that the production rate has dropped below 15 barrel of oil equivalent (boe) per day after startup of production. At a minimum, EPA should allow for a well that averages less than 15 boe per day over its first (or any) year of operation to immediately cease leak surveys or, if appropriate, reduce frequency.
4. API appreciates that EPA is proposing to include the standard cubic feet per barrel (scf/bbl) of oil ratio in the rule but, API suggests that EPA use the IRS Tax Code definition for boe of 6,000 scf/bbl.

Recommendation:

EPA should exempt low production well sites, as originally proposed in 2015, and allow for a pathway for well sites that become low production well sites due to production decline to reduce or cease monitoring. The determination should allow for demonstrating that the production rate has dropped below 15 barrel of oil equivalent (boe) per day over 12 consecutive months and reference the IRS Tax Code for boe which is 6,000 scf/bbl.

1.2.1 ADDITIONAL RECORDKEEPING AND REPORTING FOR LOW PRODUCTION WELLS

Requiring documentation that a well site meets the criteria of a low production well is appropriate. However, companies should only identify sites within the annual report as low production and not be required to report the production rate determination itself, as proposed in § 60.5420a(b)(7)(i)(E).

Providing identification of this designation should provide appropriate compliance assurance for these well sites. All records can be made available upon request by the Administrator, as necessary, for further review. If EPA were to revisit the exemption for low production well sites as originally proposed, documentation of the production determination including the methodology should be sufficient. No reporting of these well sites should be required.

In addition, there are typographical errors proposed within §60.5420a(c)(15)(iii) since we do not believe it was EPA's intent to require all well sites to document and report production values. The paragraph should refer to biennial monitoring based on the current proposed language, and the cross-reference should be reviewed to correctly refer to the appropriate paragraph (i.e. (g)(1)(ii)), as currently proposed.

Recommendation:

EPA should reduce administrative burden associated with low production wells by requiring documentation of the production rate determination as a recordkeeping requirement only.

EPA should review typographical errors to check for cross-reference issues (e.g. frequency cited in § 60.5420a(c)(15)(iii)).

1.2.2 REQUEST REMOVAL OF “NON-LOW PRODUCTION” DESCRIPTOR FOR LEAK DETECTION APPLICABILITY AND THE ASSOCIATED RECORDKEEPING AND REPORTING OF PRODUCTION VALUES

EPA has introduced the concept of a “non-low production” well for reference to and applicability of the fugitive emission requirements for new and modified locations. This descriptor is unnecessary and should be removed. Reference to and definition of “low production” well site establishes criteria for a subset of production well sites as a threshold less than 15 barrels of oil equivalent per day. It should be inferred that if this criteria is not met, then the well site does not meet this definition and is assumed to produce more than 15 barrels of oil equivalent per day.

Recommendation:

Remove the “non-low production” descriptor from the rule language since usage of the term is unnecessary.

1.3 THE PROPOSED CLARIFICATIONS TO THE DEFINITION OF WELL SITE ARE APPROPRIATE.

API supports EPA's proposed clarification to the definition of well site in § 60.5430a as it pertains to equipment owned and operated by a third-party operator at well sites and Class II disposal wells. We also support the proposed definitions of “*custody meter*” and “*custody meter assembly*.” In addition to exempting meter assemblies at well sites and Class II disposal wells, we also request EPA provide a similar exemption for meter assemblies owned and operated by third parties located at compressor stations and also exempt non-hazardous Class I wells for similar reasons noted.

- Third party owned and operated equipment at well sites: The clarification to exclude meter assemblies from the fugitive emissions standards was necessary and will alleviate legal and logistical issues that arose with compliance with Subpart OOOOa for the small number of components, as API stated in previous comments to the Agency (see August 8, 2017). Meters used in this capacity are calibrated regularly, and any leaks would be detected at the time of calibration.

- Third party owned and operated equipment at compressor stations: The same exemption should apply to custody meter assemblies at compressor stations for the same legal and logistical reasons noted for well sites. The same language provided for well sites would be appropriate to include for compressor stations to account for the correct components.
- Class II Wells: The proposed definition and exemption for Class II disposal wells and disposal facilities is appropriate. As EPA stated in the preamble, the EPA had not considered these types of wells during the development of the fugitive standards in the 2016 Subpart OOOOa. This clarification alleviates confusion to the regulated community. These wells and facilities handle produced water that has already been physically treated to remove hydrocarbon and natural gas prior to the arrival at the facility to avoid loss of revenue. Equipment and components would primarily be in water service and would not directly compare to EPA's model plant analysis accounted for in the technical support documentation.
- Non Hazardous Class I Wells: In addition to exempting Class II disposal wells, we also request EPA exempt non-hazardous Class I wells for similar reasons noted. Like Class II disposal wells, non-hazardous Class I disposal wells were not considered during the development of the fugitive emission standards in the 2016 Subpart OOOOa. Class I disposal wells are regulated by the EPA (<https://www.epa.gov/uic>) and accept industrial waste, which includes Class II waste. Non-hazardous Class I wastes are required to be sampled for laboratory analysis according to their EPA permits.

While it is clear that these components will be excluded from Subpart OOOOa requirements for sources constructed after the October 15, 2018 publication date of the proposed rule (see 42 U.S.C. § 7411(a)(2)), API requests confirmation that affected facilities with the now-excluded components that have been subject to the 2016 version of Subpart OOOOa will no longer be required to comply with Subpart OOOOa requirements for those components once the rule is finalized. Confirming this in the final rule will avoid unnecessary uncertainty and is fully consistent with the rationale EPA has provided for amending the definition of well site.

Recommendation:

EPA should maintain the proposed clarification to the definition of well site in § 60.5430a as it pertains to equipment owned and operated by a third-party operator at well sites and Class II disposal wells and should maintain the proposed definitions of "custody meter" and "custody meter assembly."

In addition to exempting meter assemblies at well sites and Class II disposal wells, EPA should also provide a similar exemption for meter assemblies owned and operated by third parties located at compressor stations. EPA should also exempt non-hazardous Class I disposal wells in addition to Class II wells.

EPA must also provide confirmation that affected facilities with the now-excluded components that have been subject to the 2016 version of Subpart OOOOa will no longer be required to comply with Subpart OOOOa requirements for those components once the rule is finalized.

1.4 MAJOR PRODUCTION AND PROCESSING EQUIPMENT SHOULD NOT INCLUDE REFERENCE TO ANCILLARY EQUIPMENT SUCH AS PNEUMATIC PUMPS AND CONTROLLERS

API supports the concept EPA introduced for classifying major production equipment for purposes of determining whether a well-site facility is considered a wellhead-only facility and the provision that monitoring can cease when the major production equipment is removed. However, the definition of major production and processing equipment proposed by EPA includes reference to smaller auxiliary type equipment including pneumatic pumps and controllers. Pneumatic pumps and controllers should not be considered major equipment for purposes of determining applicability of the fugitive emission requirements, especially given their status as separate affected facilities under Subpart OOOOa. These small ancillary equipment do not contain a significant number of components, if any, and have limited potential to emit fugitive leaks. Therefore, a well site containing only a wellhead and a small chemical injection pump would have similar number of components as a site containing only a wellhead, which EPA has established as not cost-effective. Since the equipment is designed to vent, EPA has appropriately not included the pneumatic equipment within the definition of fugitive components, and this equipment would be excluded from the fugitive emission requirements directly.

Many wells have an emergency shutdown valve that is controlled by a pneumatic controller, which would make this new definition of a wellhead-only facility obsolete in practical application. While we agree the leak detection requirements should target sites that contain large permanent process equipment (condensate or crude oil storage vessels, separators, centrifugal or reciprocating natural gas compressors, dehydration units, or heater treaters) that have more fugitive components, we suggest EPA eliminate reference to auxiliary equipment (pneumatic pumps and pneumatic controllers) within the new definition. It is overly burdensome to broadly require LDAR programs at sites with only minimal supplemental equipment that would result in minimal, if any, emission reductions.

API also requests that EPA further clarify the definition by making “compressors” specific to centrifugal or reciprocating natural gas compressors within the definition.

Recommendation:

Pneumatic pumps and controllers should not be considered major production equipment since their inclusion makes the leak survey exemption obsolete. EPA should also further clarify the definition of major production equipment to add a descriptor to make compressors specific to centrifugal or reciprocating natural gas compressors.

1.5 MODIFICATION

1.5.1 MODIFICATION TO WELL SITES

EPA continues to define a modification to well site through identification of events that can result in an increase in production (i.e., drilling a new well, hydraulic fracturing a well, or hydraulic refracturing a well). These events, in and of themselves, should not be considered a modification. These actions do not necessarily increase the number of fugitive components at a well site, which could increase fugitive emissions at a site. There are a couple of primary considerations that should be made when analyzing whether an NSPS modification has occurred:

1. Has the change resulted in an emission increase? Consistent with the definition of modification for NSPS at 40 C.F.R. § 60.14⁴, one would conclude there has not been a modification simply if a well is fractured or refractured because fugitive emissions are estimated based on EPA supported emission factors that consider only the number and type of components present at a facility. Therefore, if there is not an increase in the number of components, there would be no calculated emission rate increase from the collection of fugitive components and thus, no modification. More specifically, changes to flow or pressure are not factors in the emission estimate. It is noted that this same issue applies to fugitive components at other locations historically subject to LDAR (e.g., refineries, chemical plants, natural gas processing plants) and for those sites, changes to operating pressure or flow are not triggers for modification. Components could be brought into LDAR if there are significant changes to the composition of material (e.g., switch from < 10% VOC to > 10% VOC service), but not due to operating flow or pressure.
2. What is the appropriate comparison when assessing an hourly emission rate increase? Notwithstanding the issues noted immediately above about how fugitive emission rates are calculated, even if one were to consider EPA's argument in the preamble that an increase in flow and/or pressure results in emission increases following a hydraulic fracturing or refracturing event, one should look further back in time than just the moment prior to the operation on the well to determine if the collection of fugitive components experienced a change that increases the hourly emission rate relative to ANY hour in the past operation of collection of fugitive

⁴ § 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

components, including start of production. EPA's definition of modification ignores this important point that has been used to determine whether a modification has occurred under other NSPS rules for years.

API continues to maintain that the amount of production, in and of itself, does not increase nor decrease the amount of fugitive emissions emitted from a site with the same number of fugitive components and same approximate operating pressure⁵. For this scenario, an increase in the number of the fugitive emission components is the only modification that could increase the calculated fugitive emissions. Therefore, as long as major production equipment is not constructed along with the well activities listed (well is drilled, hydraulically fractured, or hydraulically refractured), there is no emissions increase and there is no "modification" as defined in § 60.14.

In the preamble to the proposed rule, EPA provides three justifications for its determination that refracturing a well at an existing well site constitutes a modification of the source pursuant to the Clean Air Act (CAA or "the Act") and EPA's modification rules. 83 Fed. Reg. at 52072-73. In the third of these justifications, EPA states that, even when refracturing does not result in additional equipment at an existing well site, refracturing should nonetheless be deemed a modification because:

"it is possible for increased throughput to these controlled storage vessels at a well site to exceed the design capacity of the vapor control system, which may result in additional emissions from storage vessel thief hatches or other openings."

Id. at 52073. This rationale does not offer a sufficient basis for concluding that a modification has taken place and should be rejected by EPA as a basis for reaching such a conclusion in the final rule.

Modification is defined in Section 111 of the CAA (Section 111) as

"any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

42 U.S.C. § 7411(a)(4) (*emphasis added*). EPA's third justification does not pass the statutory test for a modification. EPA's own words demonstrate that an increase in throughput causing an exceedance of a vapor control system design capacity is only "*possible*" and that such an exceedance only "*may* result in additional emissions." 83 Fed. Reg. at 52703 (*emphasis added*). If there is any possibility, even a remote one, that emissions will not increase (which EPA concedes is the case here), EPA cannot by blanket rule determine that a change will constitute a "modification" under the CAA.

Recommendation:

API requests that EPA update the rule language regarding modifications such that well site is considered modified if an operator drills a new well, hydraulic fractures a well, or hydraulic refractures a well and additional permanent process equipment is added to the site.

⁵ See Attachment C for further discussion regarding how pressure is controlled at well sites such that operating pressure for surface equipment and piping does not generally increase due to changes in well head pressure.

1.5.2 MODIFICATION TO CENTRAL TANK BATTERIES

EPA should not finalize the proposed language that a central tank battery is considered modified for the purposes of the Subpart OOOOa leak provisions when “major production equipment” is removed at the separate surface well site such that it becomes wellhead only. Similar to the above discussion of modification of a well site, the simple act of removing surface equipment at a well site feeding a tank battery does not meet the statutory definition of modification. Without a change to the number of components at the tank battery, there would be no calculated emission rate increase. Further, while API does not agree with EPA’s position on the impact of flow and pressure on fugitive emissions, even if one accepted EPA’s position, EPA must still consider all aspects of this situation. That is, if a well site’s production has declined so much that equipment has been removed and it is now a wellhead-only site, then it is highly likely that the total flow to the tank battery has not increased over a level it had experienced in the past and thus, would not see an emission increase relative to that prior level.

Even if EPA holds that there is a small, albeit unquantifiable, increase in emissions at a tank battery when a well feeding it removes some of its production equipment, API notes that the general provisions found under 40 CFR § 60.14 (e)(2) would address this situation. 40 CFR § 60.14 (e)(2) states:

(e) The following shall not, by themselves, be considered modifications under this part:

...

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

In the situation of removing “major production equipment” from a well site feeding a central tank battery, there would be no capital expenditure at the well site and certainly none at the central tank battery facility.

Further, EPA’s action to try to subject more tank batteries to Subpart OOOOa could prove to be a disincentive to operators with respect to the consolidation of equipment from wells that would actually reduce footprint and minimize emissions. When well sites become wellhead-only facilities, there is a reduction in the overall number of fugitive components. That is, the components do not move to the central tank battery. The central tank battery should only become subject to the leak provisions if major equipment is added to the central tank battery.

Recommendation:

A central tank battery should only become subject to the leak provisions if major production equipment (condensate or crude oil storage vessels, separators, centrifugal or reciprocating natural gas compressors, dehydration units, or heater treaters) are added to the central tank battery following one of the activities in § 60.5365a(i)(3)(i)-(iii) at a well site feeding the tank battery. EPA should not finalize the language proposed that triggers modification at tank battery after removal of major equipment at a separate wellsite.

1.6 COLD WEATHER TECHNICAL LIMITATIONS

1.6.1 API SUPPORTS PROVISIONS FOR ALASKAN NORTH SLOPE AS PROPOSED

We support EPA extending the timeframe for conducting the initial monitoring for all well site and compressor stations located on the Alaskan North Slope. As EPA stated in the preamble 83 Fed. Reg. at

52071, the requirements were warranted due to the area's extreme cold temperature, which is below the temperatures at which the monitoring instruments are designed to operate for approximately half of a year

1.6.2 API CONDITIONALLY SUPPORTS THE REMOVAL OF WAIVER AT § 60.5397A(G)(5)

The removal of the waiver for cold climates is adequate as long as EPA maintains the frequencies proposed in the reconsideration as annual for well sites and at least semi-annual (between 4-6 months) for compressor stations. If these minimum frequencies are not finalized, the waiver at § 60.5397a(g)(5) must be reinstated to account for inclement weather and other harsh conditions that would cause safety issues for personnel or for when temperatures may be below those approved for use of the OGI camera.

2.0 FUGITIVE EMISSIONS AT COMPRESSOR STATIONS.

2.1 EPA SHOULD REDUCE THE SURVEY FREQUENCY AT COMPRESSOR STATIONS AND COMPRESSORS SHOULD NOT BE REQUIRED TO BE SURVEYED IN OPERATING MODE AT LEAST ONCE PER YEAR

API supports the comments submitted by GPA Midstream regarding the appropriate survey frequency for compressor stations. API does not support the proposed rule change that compressors must be surveyed in operating mode at least once per year but rather believes EPA should require operators to conduct surveys with facility operations as they are found when the survey is conducted. The proposed requirement is inappropriate for the following reasons:

- The requirement to ensure engines are surveyed in operating mode will result in situations where an engine will be brought on line just to enable an LDAR survey. This will add a significant logistical burden on operators as load on compressor engines can be unpredictable and may go down without notice just prior to a scheduled LDAR survey.
- The act of starting up and then shutting down (and potentially blowing down) a compressor engine that would not otherwise be required to operate is expected to result in more emissions than might be mitigated by any leak(s) identified in the process of the survey.
- Based on experience conducting 40 CFR Part 98 Subpart W required surveys for transmission compressor stations, it is expected that EPA's proposed requirement will result in the need for multiple survey trips in order to survey all compressors. EPA did not consider the costs for multiple trips when determining cost effectiveness for conducting leak surveys.

Recommendation:

API recommends EPA reduce the survey frequency and that operators conduct leak surveys with facility operations as they are found when the survey is conducted.

2.2 MODIFICATION TO COMPRESSOR STATIONS – EPA SHOULD EDIT RULE TEXT TO ADDRESS VAPOR RECOVERY UNITS (VRUs)

With respect to VRUs, API appreciates the clarification EPA provided (83 Fed. Reg. at 52074), but we ask EPA to add regulatory language to confirm this interpretation that clarifies that a modification is

triggered when an additional compressor is added for the compression of natural gas and that the addition of a VRU compressor was not intended to trigger the leak detection requirements.

3.0 SIMPLIFICATION OF THE LEAK MONITORING PLAN REQUIREMENTS

3.1 THE SITEMAP AND OBSERVATION PATH REQUIREMENTS SHOULD BE DELETED OR MODIFIED BECAUSE THEY ARE OVERLY PRESCRIPTIVE AND DO NOT BEAR A RATIONAL RELATIONSHIP TO THE EMISSIONS REDUCTIONS SOUGHT TO BE ACHIEVED.

API opposes the sitemap and observation path requirements in Subpart OOOOa because these requirements depart from the performance standard principles underlying Section 111 of the CAA in that they unreasonably restrict how industry achieves compliance with fugitive emissions monitoring. This prescriptiveness further has the effect of unnecessarily creating potential violations of the regulations (which EPA describes as deviations, defined as failure to meet rule requirements), even where the required surveys were properly conducted. These burdensome requirements are not only costly and onerous, they also fail to advance EPA's objectives beyond what a performance-based metric would achieve and, for these reasons, do not withstand scrutiny.

API requests that EPA simplify the monitoring plan provisions as follows:

- Remove the sitemap and observation path requirements and replace with a performance objective requiring all regulated components be monitored with the OGI equipment, without prescribing the way that this be achieved within the monitoring plan.

3.1.1 MONITORING PLAN SITEMAP AND OBSERVATION PATH REQUIREMENTS – AND THE RELATED REPORTING AND RECORDKEEPING – ARE OVERLY PRESCRIPTIVE AND UNREASONABLE

EPA's sitemap and observation path requirements should be stricken, or at the very least, modified, because EPA has failed to either (i) provide sufficient reasoning in support of its rationale for these requirements, or (ii) adequately address industry concern over the burdensome nature of strict compliance with them (and consequences of characterizing departures as "deviations"). It is an axiom of administrative law that an agency's explanation of the basis for its decision must include a 'rational connection between the facts found and the choice made.' *Bowen v. Am. Hosp. Ass'n*, 476 U.S. 610, 626 (1986) (quoting *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)). Accordingly, EPA must respond with providing such explanation or change the rule in such a way that meets its objectives and allows industry flexibility in meeting them as well.

As the proposed rule stands now, its requirements and EPA's supporting statements exemplify rulemaking requirements that are not rationally connected to the agency's stated goal and that run fundamentally contrary to the performance standard approach embodied in Section 111 of CAA. At its core, Section 111 directs EPA to issue performance standards but allows affected owners/operators to decide how to meet them. EPA has traditionally recognized that "[g]enerally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally may select any measure or combination of measures that will achieve the emissions

level of the standard.”⁶ While the work practice provisions may be somewhat more specific given the nature of a work practice, the base performance standard approach remains and requires that EPA not impose requirements that are unnecessary or not rationally related to emission reduction. In this case, the observation path requirements are inefficient and provide no greater compliance assurance than a simple statement directing that all regulated components must be observed during the monitoring survey.

3.1.2 A SINGLE DEFINED OBSERVATION PATH IS INEFFICIENT AND COSTLY FOR AFFECTED INDUSTRY, AND PROVIDES NO GREATER COMPLIANCE ASSURANCE.

As EPA makes clear in the June 2016 final rule preamble statement, the fundamental goal of its “observation path” requirement is to ensure that all of the regulated components are reviewed with the OGI instrument. That goal can be met in any number of ways, and EPA’s selection of a defined “observation path” deprives companies of flexibility in achieving the performance requirement to observe the regulated components and also manufactures potential violations by requiring a particular path to be followed even if another pathway would not only ensure that all of the regulated components are reviewed but prevent a modified approach that results in a more effective survey. Such an outcome is the very definition of arbitrary and capricious rulemaking.

The single defined observation path also fails to take into account the sequence of viewing fugitive components. EPA provides no reason why a different route (or even the same route in a different order or with a break in-between), would not meet its goal. In short, the June 2016 final rule failed to justify its restriction that only *one* path may be used as part of the required monitoring surveys when there are many possible routes that would achieve the same objectives, and EPA’s response in the most recent proposal does not cure that failure.

EPA attempts to justify its overly prescriptive requirements in stating that the defined observation path is necessary because it cannot find another way to ensure owners/operators meet their compliance obligations to monitor all of their equipment.⁷ But restricting monitoring surveys to a single path has no bearing on ensuring owners or operators meet their compliance obligations, and such a restriction does little to actually serve the valid objectives enunciated in the rule. For example, an owner/operator could physically view and monitor all of the equipment during a survey but still be in violation of the rule if a small departure from the observation path was taken while en route. If anything, EPA has created more inefficiency for OGI users by tying the requirements of OGI to the more antiquated Method 21 system rather than simply establishing the performance objective for OGI users to meet.

In addition, the costs of creating, maintaining, and updating sitemaps and observation paths are onerous and unnecessarily burdensome on owners/operators at affected facilities. EPA’s statement in the Response to Comments regarding the observation path requirement is problematic because it assumes this

⁶ 79 Fed. Reg. 34960, 34,969 (Proposed Rule for *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*); see also 42 U.S.C. § 7411(b)(5) (“Except as otherwise authorized under subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance”).

⁷ See 81 Fed. Reg. at 35,860 (“[B]ecause we are no longer requiring a traditional log of instrument readings...the rule must provide another way to ensure the compliance obligation to monitor all equipment is met. We believe that the observation path requirement effectively ensures that an operator looks at all the required components...”).

is a “one time” obligation. That assumption is clearly not correct; components change over time, and this now creates a continual update requirement that itself could be violated (e.g., if a company adds a new component and the plan has not been updated, is it in violation of the requirement to have a “fugitive emissions monitoring plan” because a component that may be on a slightly different path is not included). Moreover, EPA’s assumption fails to take into account that owners/operators may now be forced to create entirely new and separate management systems for the sole purpose of maintaining sitemaps and observation paths. While the notion of a “plan” and “observation path” may have intuitive appeal, a closer analysis shows that the layers of requirements to monitor compliance with the plan, the path development, the updates to them, and compliance with following them impose significant costs that the rulemaking has completely ignored to date.

API does not generally disagree with EPA’s overall goals underlying the monitoring survey (namely, to ensure all regulated components are observed). But EPA’s requirements go beyond that which is needed to assure compliance and actually limits the rule in a way that prevents other methods that accomplish the same result. The same result could be achieved with a *simple* requirement – one that ensures that all regulated components are observed without interferences. The 2016 rule entirely failed to address this fundamental issue, and the new proposed rule would perpetuate this fundamental problem with the 2016 requirements.

3.1.3 THE SITEMAP AND OBSERVATION PATH REQUIREMENTS ARE ARTIFICIALLY MANUFACTURING “DEVIATIONS” THAT MUST BE REPORTED AS VIOLATIONS FOR SOME FACILITIES.

EPA has indicated in some documents⁸ that not following the path is “merely” a “deviation,” but a review of the deviation definition strongly suggests that regulators will consider it a violation. Indeed, if EPA wanted to make a deviation clearly not a violation, it would not have defined deviation as a “failure to meet” an obligation and would have used another word, such as “excursion.” EPA has taken such an approach before, e.g., in the Compliance Assurance Monitoring (CAM) rules, 40 C.F.R. part 64, in which the agency provided that excursions were instances in which a monitoring parameter was not met but made clear that this did not constitute a violation. As defined in Subpart OOOOa, however, deviation includes the failure to meet *any* requirement or obligation of the subpart. This logically leads to a conclusion that deviations from the observation path (and thus the monitoring plan) would likely be considered violations.

EPA states that these deviations are “not necessarily deviations from the requirements of the rule” and should even be expected by experienced OGI operators. But this reasoning does not assure owners and operators that they have not committed “deviations” because they are still vulnerable to deviation

⁸ May 2016 RTC, at 4-706, EPA-HQ-OAR-2010-0505-6811; 83 Fed. Reg. at 52078.

reporting under other rules.⁹ For example, some facilities subject to this rule are also subject to Title V permitting requirements. Pursuant to the Title V program, those operators must report all deviations. Those same facilities could also be subject to citations by states that elect to pursue them for their “deviations” from the rule, e.g., failing to follow the observation path as defined. EPA’s assurances that are not reflected in the rule provisions or definitions do nothing to change the enforcement risk faced by these facilities or their obligation to report intermittent compliance status for those facilities subject to Title V permitting. It is possible that the proposal is merely stating that EPA would exercise its enforcement discretion not to pursue deviations (violations) of the observation path and sitemap provisions if they did not make a difference in the effectiveness of the observations, but a commitment to exercise discretion does not make an arbitrary provision rational.¹⁰

3.1.4 EPA SHOULD REVISE THE OBSERVATION PATH REQUIREMENT INTO A GENERAL PERFORMANCE OBJECTIVE.

API agrees with EPA that a monitoring plan is one rational way to implement the OGI requirements. It is the prescriptiveness in the elements of the plan with which API takes issue. Surveyors should ensure they have a clear view of all fugitive components during the surveys. The approach that should be taken to achieve this outcome, however, is one consistent with fundamental CAA Section 111 principles by setting the core requirements but not specifying how an owner/operator achieves those requirements. For example, EPA could specify that observations require the following elements: (1) clear views, (2) monitoring of all equipment, and (3) accurate imaging. Such a regulation would be in line with past CAA Section 111 rules and allow industry flexibility in achieving those metrics. Therefore, EPA should amend the rule to provide that each monitoring plan must include or state the following: *“Each monitoring survey shall be conducted in such a manner to ensure all fugitive components are surveyed.”* No more is required.

A company may elect to create a pathway so that it can prove it observed all required components, but that should not be a requirement of the rule. Fundamentally, companies will need a basis for certifying that they met the requirements of the rule, but there is no reason that EPA should impose a one-way only methodology for doing that. This approach would ensure that all fugitive components are included in the monitoring survey while allowing industry to find the most suitable approach to achieving that objective. The sitemap and observation path currently prescribed by EPA would merely represent one of those approaches.¹¹ An example of the type of description that an operator may choose to include within their plan describing a general process is provided in Attachment D.

⁹ API acknowledges that the proposed rule eliminates some of the reporting requirements that would have required *all* deviations from the monitoring plan – including the observation path – to be reported in the facility’s annual reports required under this subpart.

¹⁰ EPA has also publicly stated that it does not intend to issue guidance on the monitoring plan – this shows EPA has no real intent to ensure that owners and operators are not subjected to unwarranted enforcement as a result of not following the defined observation path closely enough. It is in this sense that deviations will have been *manufactured* by EPA.

¹¹ In this scenario, EPA could also create a “safe harbor” provision that allows using the sitemap and observation path as one way for owners/operators to be deemed in compliance.

If EPA retains a “path” requirement, then departures from the observation path should be considered “excursions” and not deviations. EPA has stated that deviations from the monitoring plan are not necessarily deviations from rule requirements. Thus, “deviation” is not the appropriate label for a departure from the observation path. The definitions for Compliance Assurance Monitoring under 40 C.F.R. part 64 provide for an “excursion,” and that approach should be adopted here (with modification); the). The Compliance Assurance Monitoring definition provides:

“Excursion shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.”

To the extent EPA includes any pathway provisions, deviations should not be considered a failure to meet the requirements of the rule. Instead, EPA could adopt an “excursion” definition along the following lines, based on 40 CFR §64.1:

“An “excursion” shall mean a departure from the observation path, as outlined in § 60.5397a(d), for an established monitoring plan under this part, that does not result in an omission by a monitoring surveyor to view or inspect any required emissions components, and/or does not interfere with the view or accuracy of the OGI equipment or operator in completing the survey of all required emissions components. An excursion is not a deviation from the requirements of this subpart.”

By using “excursion” to define the departure from the observation path, EPA could still identify when departures occurred, and owners and operators would be less vulnerable to “deviation” citations under other rules. A deviation would only occur if the surveys were made without clear views, failed to monitor all required components, and/or did not have accurate imaging. This characterization of a departure also comports with EPA’s current understanding, since EPA states that it does not view all “departures” from the monitoring plan as deviations. An “excursion” would still allow a departure to be taken and noted but not result in a deviation/violation from the requirements of the rule.

4.0 EPA SHOULD DO MORE TO REDUCE AND SIMPLIFY ACTUAL BURDEN ASSOCIATED WITH RECORDKEEPING AND REPORTING

Subpart OOOOa continues to require onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. In this proposal, EPA increased the recordkeeping and reporting requirements under the guise of streamlining requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require.

Furthermore, EPA requires a certifying official submit certification of all information submitted within the annual report in compliance to Subpart OOOOa. API believes that general recordkeeping of leak monitoring surveys provides compliance assurance and validates completion of surveys, including the identification of leaks and their repair.

4.1 REQUIREMENTS CREATE AN UNNECESSARY REGULATORY BURDEN AND ARE THEREFORE AT ODDS WITH EXECUTIVE ORDERS 13771, 13563, AND 12866.

The current proposed rule fails to meet the objectives of Executive Orders (EO) 13771, 13563, and 12866 as a result of the arbitrary restriction imposed on owners and operators to comply with a single defined observation path. Taken together, these Executive Orders direct and encourage federal agencies to reduce regulatory burdens and costs, implement regulations that are cost-effective, and consider the effect and need for the regulations on society, including private industry.

More specifically, EO 13771 directs executive agencies, including the EPA, to reduce regulation and control regulatory costs.¹² EO 13771 provides that “It is the policy of the executive branch to be prudent and financially responsible in the expenditure of funds, from both public and private sources.”¹³ EO 13771 further provides that “the cost of planned regulations be prudently managed and controlled.”¹⁴ In 1993, EO 12866 was issued to announce a regulatory policy that directs federal agencies to “promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need,” and in making such a determination, “to assess all costs and benefits including the alternative of not regulating.”¹⁵ EO 12866 also directs agencies to “design its regulations in the most *cost-effective* manner to achieve the regulatory objective.”¹⁶

In 2011, EO 13563 was issued to be “supplemental to and reaffirms the principles, structures, and definitions governing contemporary regulatory review that were established in Executive Order 12866 of September 30, 1993.”¹⁷ EO 13563 expressly reiterates and affirms that each agency must (among other things) “propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs...” “tailor its regulations to impose the least burden on society ... taking into account...the costs of cumulative regulations,” and “to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt.”¹⁸

As discussed above, EPA has yet to provide a reasoned explanation or guidance as to why its restrictive approach is reasonable. The current proposed rule creates a significant monetary, resource, and management intensive regulatory burden on owners and operators subject to subpart OOOOa that provides little, if any, benefit, and could be achieved by much simpler and more flexible means (e.g. performance objectives for each monitoring survey). Neither the final rule or current proposed rule align with the objectives of these EOs.

Recommendation:

API respectfully requests that EPA carefully consider the objectives in EO 13771, 13563, and 12866 and as a result of that review, delete or substantially modify the requirements as discussed in these comments.

¹² E.O. 13771 of Jan 30, 2017.

¹³ *Id.*

¹⁴ *Id.*

¹⁵ E.O. 12866 of Sept. 30, 1993.

¹⁶ *Id.* (emphasis added).

¹⁷ E.O. 13563 of Jan. 21, 2011.

¹⁸ *Id.* (emphasis added).

4.2 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

EPA continues to ignore the scale of sites that are subject and will become subject to these provisions over time. We continue to request the Agency seek to reduce the administrative burden to operators by reducing the amount of records required to be maintained and reported for each leak survey. API recognizes that it is appropriate to maintain sufficient records to demonstrate that fugitive emissions are adequately identified and subsequently repaired. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted.

4.2.1 RECORDKEEPING FOR FUGITIVES

API appreciates EPA's proposed changes to allow for a unique identifier for survey personnel, protecting the privacy of company employees and contractors.

The general recordkeeping of leak monitoring surveys provides compliance assurance and validates completion of surveys, including the identification of leaks and their repair. The additional photographs required to be maintained do not provide additional assurance beyond the survey records maintained, submitted and certified in the annual report. Maintaining thousands of photographs in addition to the details required to be recorded is additional cost and administrative burden to track and organize. The level of data required for recordkeeping and reporting within Subpart OOOOa already includes significantly more data points than other traditional LDAR programs. As stated in our petition for reconsideration, EPA should reduce the recordkeeping burden for conducting the leak monitoring by removing the digital photo requirement for each OGI survey. At a minimum, EPA should modify the rule to make the photo requirement optional similar to that for reduced emission completion recordkeeping, where the use of photographs is an alternative in place of other recordkeeping requirements.

Within this proposal EPA has also added additional data points that should be eliminated or simplified as we discussed throughout Comment 1.0.

EPA should remove the following recordkeeping requirements:

- Digital photographs.
- When using OGI, ambient temperature, sky conditions, and reference to max wind speed (i.e. document wind speed only).
- Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding
- Number and type of components that were tagged as a result of not being repaired during the monitoring survey.
- Repair methods applied in each attempt to repair beyond identification that the leak was fixed.

This would still retain a substantial amount of the recordkeeping information per survey including:

- Location of each fugitive emission.
- Number and type of components for which fugitive emissions were detected.
- Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

- Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.
- Number and type of fugitive emissions components that were not repaired as required.
- Number and type of components that were tagged as a result of not being repaired during the monitoring survey.
- Repair methods applied in each attempt to repair.
- Number and type of fugitive emission components placed on delay of repair and explanation for each.
- Date of the survey.
- Beginning and end time of the survey.
- Monitoring instrument used.
- Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.
- Wind speed at the time of the survey.
- Narrative of how survey process was performed or statement no excursions from the narrative in the monitoring plan occurred.

Recommendation:

EPA should simplify the recordkeeping and reporting requirements to those that ensure compliance without additional administrative burden. Some examples include removal of the digital photographs and elimination of tracking environmental conditions beyond wind speed. Only elements needed for compliance assurance should be requested within the annual report. Supporting records retained by companies can be made available upon request from the Agency.

4.2.2 REPORTING FOR FUGITIVES

All of the existing reporting requirements are not necessary for the agency to assess whether ongoing compliance is being attained. It is incumbent on all reporting entities to self-report any non-compliance with the regulation. As part of the existing reporting, entities are required to inform the agency of any deviations from requirements. It would substantially reduce the reporting burden if entities were only required to submit limited information that would make known any compliance issues that occurred during the reporting period. In the absence of such issues, it is excessive to require the provision of every detail for every survey of every affected facility.

Recommendation:

API requests that EPA limit the reporting requirements to the most relevant information to assure compliance focused on the identification and subsequent repair of leaking components. We believe this can be achieved by the following data points, which is consistent with the level and format of data state programs require. As we have stated before, supporting records can be made available to the Administrator upon request:

- Site ID

- Date of the survey;
- Number and type of components for which fugitive emissions were detected;
- Number and type of fugitive emissions components that were not repaired as required;
- Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;;
- Deviations from requirements associated with survey frequency and repair time; and
- Identification a well site meets the criteria for wellhead only and will cease monitoring.

4.2.3 NEWLY PROPOSED RECORDKEEPING AND REPORTING ELEMENTS SHOULD BE REMOVED

Additionally, EPA has proposed additional reporting specific to leak monitoring. These data points should not be finalized for reporting as proposed. Examples of these reporting elements include:

- *Low production determination by well site:* The determination should be documented and records retained. The production rate itself should not be reported. If biennial monitoring frequency is retained, companies can provide documentation that the well meets the criteria for being a low production well site. See Comment 1.2.1
- *For wellhead only sites:* API requests EPA simplify the reporting associated with the removal of equipment at a well site resulting in it becoming a wellhead only facility. EPA should simplify the reporting requirements to a one-time notification within the annual report for that well site. If equipment is added back to the site, leak detection would resume, and the well site would have full reporting information associated with it. Therefore, the following information is unnecessary to be recorded or reported:
 - o Date of removal of the last piece of major production and processing equipment
 - o Well ID or separate tank battery ID receiving the production.
 - o Date first piece of major production and processing equipment added back.

4.2.4 REPORTING FOR EQUIVALENT STATE PROGRAMS

State Agencies have recordkeeping and reporting requirements to ensure compliance with their leak detection programs, and. EPA should give proper deference to states for compliance assurance for their state programs. Complying with multiple recordkeeping and reporting schemes for the same site(s) is an enormous administrative burden for operators to maintain with no added environmental benefit. Requiring federal reporting, as EPA has proposed, would require Subpart OOOOa recordkeeping requirements to be met in order to comply with the reporting elements required in § 60.5420a(b)(7). Since EPA has proposed equivalence to the state recordkeeping programs, we also request EPA defer equivalency of reporting. Without doing so will defeat the purpose, and any benefit from EPA approving these state programs in the first place.

Additionally, EPA requires an advance notice within 90 days that a site is complying with the state LDAR program. API recommends that a one-time notification be submitted prior to the first LDAR survey (similar to written / electronic notification process associated with hydraulic fracturing of a well).

Additional comments on this topic are provided in Comment 6.0

4.3 OTHER RECORDKEEPING AND REPORTING SIMPLIFICATION REQUESTS

API has provided comments on recordkeeping and reporting aspects of Subpart OOOOa throughout this comment letter. Below is a list of each topic and the section that can be cross referenced:

- Technical Infeasibility assessments for pneumatic pumps - Comment 8.2
- CVS Inspections – Comment 10.2
- Well Completion Operations that Immediately Start Production – Comment 11.3
- Performance Testing - The previous rule required operators to conduct a visible emissions test only and the change in administrative burden with respect to reporting has not been adequately explained or justified.
 - Was the combustion unit returned to operation from a maintenance or repair activity?
 - Date of visible emissions test
 - Length of the test
 - Amount of time visible emissions present

4.4 TESTING AND REVIEW OF THE CEDRI REPORTING FORM

There are significant changes to the CEDRI forms and API and industry should be afforded more time to review. Some initial feedback includes the following:

- The form includes numerous data elements not required for reporting. EPA should remove any reporting requirement that is listed as optional. These fields are not required and add unnecessary information to an already long list of reporting requirements.
- API believes the form should be tested and reviewed with industry prior to the Final Template's release. The current version has various issues such as cells being locked and drop-downs not working consistently as well as missing relevant options.
- Through the guise of streamlining reporting, EPA has added significantly to data required to be included within the annual report. Many of these data points previously only were required to be maintained through recordkeeping. The administrative burden with respect to reporting has not been adequately explained or justified within the proposed rule.

5.0 PROVISIONS FOR NEW AND EMERGING TECHNOLOGY ALTERNATIVE MEANS OF EMISSION LIMITATION

Less expensive and more effective monitoring technologies will accelerate the production of clean domestic energy, helping to deliver a healthy environment and economy. EPA must revise the AMEL provisions of Subpart OOOOa to unlock the benefits of these emerging technologies.

5.1 API SUPPORTS THE OPTIONS IN THE PROPOSED RULE TO USE MODELING, TO TEST TECHNOLOGIES IN A CONTROLLED TEST ENVIRONMENT, AND TO ALLOW MANUFACTURERS/VENDORS TO APPLY FOR APPROVALS.

5.1.1 MODELING

API strongly supports the inclusion of modeling, in addition to limited field data, to demonstrate the performance of a specific technology. This is a preferred and recommended option to the onerous requirement to gather 12 months of field data. The 2018 Interstate Technology and Regulatory Council (“ITRC”) paper states, “Computer modeling is highly valuable for evaluating emission reduction objectives due to the probabilistic nature of emission rates.”¹⁹ The paper also states that “computer-based modeling, coupled with empirical validation of model accuracy, is a potential solution to rigorously evaluate application efficacy under the most likely encountered meteorological and site conditions. The Fugitive Emissions Abatement Simulation Toolkit (FEAST) model is a virtual gas field simulator that predicts emission reductions of various leak detection and repair programs. An effective demonstration of equivalency could include an empirical evaluation of an application at a structurally complex site such as a gathering compressor station over a time period, such as twelve months, that assesses performance under a wide range of meteorological conditions. If a computer model can accurately predict the detection limit and response time for different sources as a function of environmental parameters, then a probabilistic model can be used to simulate performance at other sites. This approach could allow a scientifically rigorous determination of equivalency while minimizing the number of sites required for field testing.”²⁰ Additionally, modeling is a highly valuable tool in that it allows for comparison of the “end game” of equivalent emissions reductions (i.e., allows for comparison of two approaches/work practices rather than specific technology detection thresholds).

Further, EPA used modeled simulations when it simulated the frequency and distribution of leaks in order to compare OGI to Method 21 and approve OGI as an “alternative work practice to detect leaks from equipment” (“OGI AWP”).²¹ EPA used a Monte Carlo model to evaluate and approve the use of OGI as an alternative work practice (AWP) for fugitive emissions monitoring. “In developing the AWP, EPA sought to design a program for using the optical gas imaging instrument that would provide for emissions reductions of leaking equipment at least as equivalent as the current work practice. To do so, we used the Monte Carlo model for determining what leak rate definition and what monitoring frequency were necessary for the AWP.” At no point in its approval of OGI did EPA require site-specific modeling.

We strongly urge EPA to apply the same logic to AMEL equivalence demonstrations. There is no reason why rigorous statistical modeling, combined with real-world field data and thorough documentation and recordkeeping, should not be sufficient for EPA to make a reasoned decision on broadly approving a new technology.

¹⁹ Interstate Technology and Regulatory Council (ITRC). 2018. Evaluation of Innovative Methane Detection Technologies. Section 5.2 Design Elements. Methane-1. Washington D.C.: Interstate Technology and Regulatory Council, Methane team. <https://methane-1.itrcweb.org>

²⁰ *Id.*

²¹ Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78201 (add date)

5.1.2 CONTROLLED TEST ENVIRONMENT

Use of a controlled test environment, such as Colorado State University's Methane Emissions Technology Evaluation Centre (METEC) to gather field data on the performance of various leak detection technologies and compare their capabilities to current approved methods, such as OGI, would greatly streamline the process of determining equivalence, as well as the lengthy CAA Section 111(h) application and approval process. API appreciates EPA including this option in the proposal and further recommends that a facility such as METEC be recognized by EPA as a facility where all suitable technologies could be tested for equivalency. The team at METEC is currently working to establish a baseline for OGI for this very purpose. In fact, EPA has funded work at METEC toward developing the baseline for OGI. Testing a new technology against a clearly established baseline and following a pre-set methodology for testing would provide consistency and confidence in the process. If manufacturers are aware of baseline emissions reduction for OGI, they would clearly know what standard their technology must meet to be deemed equivalent. As a result, this would streamline the process and allow new technologies to successfully navigate this application and approval process and be deployed faster. This would result in faster, cost-effective emissions reductions.

The ITRC paper referenced above supports this concept and states, "Controlled releases under field conditions are ideal for systems with emission source objectives because they can assess the accuracy of source quantification and/or localization under realistic meteorological conditions. Long-term testing at field sites allows controlled releases to be tested under a diversity of meteorological conditions. Performing multiple controlled releases under each set of conditions can be used to calculate the probability of detection as a function of emission rates and other relevant conditions such as wind speed."²² Therefore, gathering field data at a facility such as METEC would prove extremely useful and could effectively take the place of gathering field data at an active oil and gas well site. API recommends that testing technologies in a controlled test environment, in addition to modeling, to minimize the field data necessary to demonstrate the performance of various technologies and achieve approvals.

5.1.3 VENDORS/MANUFACTURERS SHOULD BE ALLOWED TO APPLY FOR APPROVAL OF EMERGING TECHNOLOGY

Vendors/manufacturers of new leak detection technologies are the experts in this advanced, high-tech area and are the appropriate person(s) to apply for approval of a technology to be used in compliance with Subpart OOOOa for methane and/or VOC leak detection. API appreciates the inclusion of this language in the proposal. However, API recommends that the operator not be required to be a party to the application and approval process as well since the technologies are being developed for broad applicability.

²² *Id.*

5.2 EPA SHOULD ALLOW FOR BASIN-WIDE APPROVALS OF EMERGING TECHNOLOGY FOR USE IN COMPLYING WITH THE LEAK DETECTION REQUIREMENTS IN THE RULE.

One of API's priority concerns in the proposed Subpart OOOOa technical revisions is the requirement to apply for the use of emerging technologies on a site-specific level. Outlined below are the technical and legal reasons why this would be an enormous and unnecessary burden, not feasible to undertake from an administrative and timing perspective, not necessary for showing equivalence to the current method, and will greatly stifle innovation in this very dynamic area of technological advancement.

Numerous technologies are currently being developed and piloted at oil and gas field sites throughout the country. Many of these state-of-the-art technologies in development have the potential to detect leaks faster and more efficiently, which could enable the operators to make timely repairs resulting in less fugitive emissions, resulting in a win-win for both the operator and the environment.

5.2.1 SITE-SPECIFIC VARIABLES CAN BE ADDRESSED IN CONDITIONS REQUIRED FOR THE USE OF THE TECHNOLOGY

In the proposal, EPA states that "we are not changing the requirement that AMEL's be site-specific because we are aware of the variability of this sector and are concerned that the procedures may need to be adjusted based on site-specific conditions (e.g., gas compositions, allowable emission or landscape)."²³ There is no logic behind this statement, and this reasoning does not withstand scrutiny. If a technology is designed to measure methane molecules in the atmosphere, it will measure methane molecules in the atmosphere, regardless of what the site looks like or the gas composition. If there is methane above a certain concentration, the technology should find it. Further, EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions. The approval of the technology could have certain conditions assigned to it that are required to be met in order for the technology to be used at a site, similar to EPA's technology-based approval for OGI that had minimum/maximum temperatures and minimum/maximum distance parameters required to be present, for example.

In response to EPA's mention of landscaping being a site-specific variable, if the landscaping at a particular site impedes the path of the technology to effectively operate, for example, then the technology may not be used at that site until the landscaping is in compliance with the parameters required to be met for the proper operation of the specific technology. Again, this could be a condition for the use of a specific technology at a specific site. Continuous sensors, for example, allow for continuously monitoring a site for leaks and are particularly suited for intermittent leaks at very low thresholds. Day or night time is immaterial for detection by continuous sensors. On the other hand, aerial-based surveys might have limitations flying at night and may use sunlight as reference. As such, these surveys would need to be deployed only during the daytime.

EPA stating that a technology should be able to distinguish allowable emissions as a site-specific variable is irrelevant to the case for a site-specific approval. Every site has allowable emissions that could result in some venting that is allowed if under threshold levels. Differentiating allowable venting, for example, from fugitive emissions leaks could arguably be an issue against the approval of any technology but that

²³ Subpart OOOOa Proposed Technical Revisions, 83 Fed. Reg. 52080 (October 15, 2018)

should not be a reason to disallow approval on a basin-wide level and stifle all development in this important area. An approach where detection may be impacted by allowable emissions may be an approach that is used to direct inspection efforts. Some technologies could be used as a frequent screening tool and may require the operator to visit the site with OGI, for example, to detect the source of the leak(s). But it would flag the large emitter sites and again, enable the operator to find and fix the largest leaks faster.

In the OGI AWP final rule, EPA stated, “the standard is an alternative to the existing work practice and maybe used in place of the existing work practice where feasible and whenever the owner or operator chooses to do so.”²⁴ As this language clearly states, OGI received approval from the EPA, but if a site did not meet the conditions then the technology was deemed not feasible at that site at that time. Similarly, EPA should provide approvals for alternative technologies and include qualifications for their use “where feasible

5.2.2 SITE SPECIFIC DATA IS NOT NECESSARY TO DETERMINE EQUIVALENCY AND RECEIVE APPROVAL PER CLEAN AIR ACT 111(h)

There is no legal impediment to demonstrating that an AMEL is equivalent to a Section 111(h)(1) of CAA standard based on differences between the AMEL and the standard against which it is being evaluated – such as differences in the frequency (e.g., annual, semi-annual, quarterly) over which the monitoring or other requirements must occur. The current regulations for implementing Subpart OOOOa state that EPA “may condition permission [to use an AMEL] on requirements related to the operation and maintenance of the alternative means.” 40 C.F.R. § 60.5398a(a). Such requirements could easily include frequency of the deployment or operation of the AMEL.

The technologies being developed have different methane sensitivity thresholds and can operate at different frequencies. For example, a spectrometer (i.e., laser-based technology) mounted on an airplane can scan over an entire basin in a day. It could do these fly-overs more quickly and efficiently than a person using a hand held OGI camera on foot at a site and therefore, could have a higher frequency assigned to it and this would be a feasible alternative. Based on cost-benefit analysis, some of these emerging technologies have been shown to be favorable and a preferred option for some member operators.

In the OGI AWP, EPA states, “The emission control effectiveness of any work practice is a function of both 1) its ability to detect leakage and 2) the frequency of monitoring. An equivalent work practice may require more frequent monitoring, depending on its mass rate threshold for detecting leaks.”²⁵ If the fly-over technology has a lower sensitivity threshold, it may only find larger leaks, but it could find these larger leaks faster with a more frequent monitoring schedule.

²⁴ Alternative Work Practice to Detect Leaks From Equipment Final Rule (73 Fed. Reg. 78204)

²⁵ Alternative Work Practice to Detect Leaks From Equipment Proposed Rule (71 Fed. Reg. 17404)

EPA further states, “A more frequent monitoring requirement becomes necessary because higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected.”²⁶ Of Equivalency in Section 111(h)(3) is discussed simply as “a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant [under the current work practice].” Based on this standard in the statute, larger leaks found earlier and more frequently should reasonably be able to offset smaller leaks that may not be found as timely.

Further, in referring to OGI in the AWP final rule, EPA stated, “The results show that the AWP will achieve EPA’s goal of detecting leaking equipment from which the majority of emissions arise.”²⁷

Therefore, similar to EPA’s approach in the AWP OGI rulemaking, EPA should focus on basin-wide (or category-wide) mitigation equivalence, not detection equivalence. For example, a one-time aerial-based survey with a more cost effective, less sensitive technology may not be able to detect emissions with the same sensitivity as ground-based technologies, or detection equivalence, but conducting multiple surveys instead of one would mean that any potential fat-tail emission sources are identified ten times faster than a ground-based method. Mitigation equivalence can only be achieved across many sites, because of the relatively few sites that produce the bulk of emissions. Further, basin-wide approaches are likely to be more accurate in terms of estimating total emission reductions than individual site estimates given the high variability in individual site emissions.

EPA can use statistical models such as FEAST to make data-driven decisions about equivalence. EPA can then incorporate basin-specific emissions data into modeling to ensure that its emission reduction objectives are being met. Making decisions based on aggregated data reduces the uncertainty that comes with site-specific estimates. API recommends that site attributes could be obtained from a small number of representative sites in the basin; then that data, coupled with modeling and testing in a controlled test environment would be adequate to determine if equivalency is achieved. Further, once a technology is approved to be used in a specific basin, all new well sites drilled and constructed in that basin going forward will have the opportunity to use that technology without going through the onerous 111(h) application and approval process for each new site or groups of new sites all over again. Again, the proposed approval process is not feasible and would stifle development of leak detection technologies.

Therefore, based on this information and EPA’s logic in this previous OGI AWP rulemaking, once this technology has been deemed equivalent based on emissions reductions achieved in a specific basin, use of the technology in that basin should be the subject of the application for approval. As explained above, the approval could be granted with conditions that would need to be met at each site prior to the technology being used.

²⁶ *Id.*

²⁷ Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78203, (add date)

5.2.3 COMMON SENSE DICTATES BASIN-LEVEL APPROVAL

Clean Air Act section 111(h) requires that an alternative work practice must first be shown to be equivalent and then be subject to a notice and comment period and possible public hearing. Gathering the field data, performing modeling, and showing equivalence will be a lengthy process of at least a year or more. Then the notice and comment period will take months. EPA stated in the Subpart OOOOa final rule that they would make a decision within 6 months of close of the comment period.²⁸ Therefore, realistically, this process would take approximately two years. To do this for every single well site, such as a well or wells on a pad or a centralized tank battery would be unmanageable. It would be lengthy and it is unlikely that a vendor/manufacturer or operator would undertake the effort.

One API member who operates solely in the Permian Basin in Texas reported hundreds well sites subject to the Subpart OOOOa LDAR monitoring for 2018. Going through this 111(h) process for each of these sites in order to use a new, more effective and efficient technology to detect methane emissions for compliance could take at least two years per site. This does not account for the new wells this operator is drilling in the Permian Basin every month (with about 3 wells/pad or well site) and building around 4-6 large centralized tank batteries per year that would also require site-specific approval per the current language in the rule.

API requests that EPA reconsider this site-specific approach and approve a basin-wide (or category-wide) approach. Not doing so would stifle innovation in this technologically advanced, dynamic area. The environmental benefit of the rule could continue to increase if EPA would allow more than handheld OGI cameras or Method 21 to detect leaks in compliance with Subpart OOOOa.

5.2.4 CLEAN AIR ACT SEC. 111(H)(3) DOES NOT CONSTRAIN BASIN-WIDE APPROVALS

EPA should provide a procedure for approving an Alternative Means of Emission Limitation (“AMEL”) under Subpart OOOOa for categories of sources rather than limit an AMEL to an inefficient and unworkable source-by-source application. The structure and language of section 111 and EPA’s decision to allow for similar flexibilities under other CAA provisions confirm that applying an AMEL to source categories is appropriate and lawful.

CAA Section 111 calls on the Administrator to list “categories of stationary sources” that “cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” 42 U.S.C. § 7411(b)(1)(A). The Act then calls on the Administrator to promulgate and subsequently revise every eight years, if appropriate, “standards of performance for new sources within such source category.” *Id.* § 7411(b)(1)(B). The Act defines a standard of performance for purposes of section 111 as:

“a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”

²⁸ Subpart OOOOa Final Rule, 81 Fed. Reg. 35861 (June 3, 2016)

Id. § 7411(a)(1). In the event it is not feasible to establish such a standard, section 111(h)(1) authorizes the Administrator instead to “promulgate a design, equipment, work practice, or operational standard, or combination thereof.” *Id.* § 7411(h)(1). Section 111(h)(1) does not refer to categories of sources or individual sources, but because a section 111(h) standard is intended to replace a standard of performance applicable to an entire source category, the logical inference is that section 111(h) standards also apply to source categories. Section 111(h)(3) provides for an AMEL when:

“after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an [AMEL] will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of [section 111(h)(1)].”

Id. § 111(h)(3). On the face of this language, because any AMEL will serve as a replacement for a category-wide 111(h)(1) standard, any demonstration that an AMEL will achieve an emission reduction at least equivalent to a 111(h)(1) standard could reasonably be made on a category-wide basis and be applied to an entire source category.

Section 111(h)(3) also states, however, that once a successful equivalency demonstration has been made, “the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant.” *Id.* The fact that this provision has been used for the authorization of source-specific AMEL applications should not be interpreted to preclude EPA’s authorization of an AMEL on a source category-wide basis. Indeed, provided an adequate demonstration for a single source within a source category can be made and it can be established that there are no material differences between that source and the other sources in the category that would render the AMEL less than equivalent to a section 111(h)(1) standard, there is no reason, based on the statute, to prohibit category-wide application of AMEL. Indeed, any other number of approaches, including a more generalized approach that does not focus on individual sources for making an adequate category-wide demonstration under Section 111(h)(3) may be available, and EPA should evaluate them on a case-by-case basis.

Allowing for source category-wide AMEL determinations would be consistent not only with the overall structure of section 111 and its focus on category-wide standards under sections 111(b) and 111(h)(1); it is also consistent with the limitation prohibiting EPA from imposing specific technological emission reduction requirements pursuant to Section 111. Section 111(b)(5) states:

“Except as otherwise authorized under subsection (h) ..., nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.”

Id. § 7411(b)(5). Section 111(h)(1) allows EPA, under limited circumstances, to impose a standard “which reflects the best technological system of continuous emission reduction.” Section 111(h)(3) serves as a safety valve on that authority and thereby functions to further the policy set out in Section 111(b)(5). To give full effect to that policy, EPA should allow for category-wide AMEL demonstrations.

Adopting such an interpretation for Section 111(h)(3) would also be consistent with the policy EPA has adopted for the nearly identical provision in Section 112(h)(3), which authorizes an AMEL under the provisions of the CAA governing national emission standards for hazardous air pollutants. EPA’s regulation implementing section 112(h)(3) recognizes that EPA is authorized to approve an AMEL for

“source(s) or category(ies) of sources on which the alternative means will achieve equivalent emission reductions.” 40 C.F.R. § 61.12 (emphasis added). Given the similarities between the programs authorized under Section 111 and section 112 and, in particular, the similarity of Section 111(h)(3) and 112(h)(3), EPA should adopt its policy of applying an AMEL to source categories for Section 111(h)(3) in the same manner as it has done with respect to section 112(h)(3).

Moreover, EPA has adopted similarly flexible approaches under other provisions of the CAA. For example, under the Act’s visibility provisions, EPA must require states to include in their state implementation plans measures reflecting “best available retrofit technology” (“BART”) for certain “major stationary sources.” 42 U.S.C. § 7491(b)(2)(A). The Act further states that BART must control emissions “from such source,” and defines BART as taking into account, among other things, “any existing pollution control technology in use at the source” and “the remaining useful life of the source.” *Id.* § 7491(b)(2)(A), (g)(2). Despite the focus of the statutory language on determinations for individual sources, EPA’s rules allow EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, in lieu of imposing source-specific emission limits or source-specific alternatives to such limits. 40 C.F.R. § 51.208(e)(2). The courts have consistently affirmed the authority of EPA and the states in this regard. *See, e.g., Util. Air Regulatory Grp. v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Central Ariz. Water Conserv. Distr. v. EPA*, 990 F.2d 1531 (9th Cir. 1993). If alternatives to emission limits (or work practice standards) for groups of sources under these provisions are permissible despite the continued references to the term “source,” then surely a source category-wide AMEL is permissible under section 111(h)(3).

6.0 ALTERNATIVE MEANS OF EMISSION LIMITATIONS FOR STATE EQUIVALENCY

6.1 EPA SHOULD RECOGNIZE THE APPROVED STATE PROGRAMS AS WHOLLY EQUIVALENT LDAR PROGRAMS AND FULLY DELEGATE THE IMPLEMENTATION OF THE LDAR MONITORING PROVISIONS TO THESE RESPECTIVE STATES

In the state LDAR program equivalency guidance document EPA provided with this rulemaking, EPA explained that they analyzed the sensitivity thresholds and monitoring frequencies of approved technologies in a number of state programs, as well as other program requirements and, based on all of these variables combined, deemed these various state programs equivalent to Subpart OOOOa’s LDAR program.²⁹ However, EPA is requiring operators to use the fugitive emission component definition from Subpart OOOOa, in addition to the reporting and monitoring plan.

Under the well-established premise of cooperative federalism, EPA should recognize these programs in full, including the states’ recordkeeping and reporting requirements. Cooperative federalism is a central tenet of the Clean Air Act. Over the course of its fifty-year history, the Act has evolved first from a set of general principles intended to guide States as they undertook regulation of air pollution sources to an extensive number of more targeted standards often prescribed by the federal government in the first

²⁹ <https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0041> – Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa dated April 12, 2018. .

instance and then implemented by the states. The principle that the States and the federal government will work in tandem to protect the nation's air resources is embodied throughout the Act. Congress, in section 101(a)(3) of the Act, declared air pollution control to be "the primary responsibility of States and local governments," 42 U.S.C. § 7401(a)(3), with the federal government providing "financial assistance and leadership," *id.* § 7401(a)(4).

For example, pursuant to section 110 of the CAA, while EPA develops the national ambient air quality standards, *see* 42 U.S.C. §§ 7408, 7409, states develop plans, called state implementation plans, to meet those standards. In that context, the U.S. Supreme Court has made clear that "[t]he Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards." *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975). Similarly, under the CAA's visibility provisions, states have broad leeway to develop plans to combat regional haze that EPA cannot second-guess if the states have considered the statutory factors. *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002).

Section 111 of the CAA, the provision at issue here, fits squarely within the cooperative federalism tradition, with section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has ... to implement and enforce such standards." 42 U.S.C. § 7411(c)(1). The Supreme Court has affirmed that these cooperative principles are the heart of the CAA again and again. *See, e.g., Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 470 (2001) ("It is to the States that the CAA assigns initial and primary responsibility for deciding what emissions reductions will be required from which sources."); *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) ("Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent.").

We provide additional comments on specific reporting elements in Comment 4.2.4.

6.2 ALTERNATIVELY, EPA COULD REQUIRE THE FUGITIVE EMISSIONS COMPONENT DEFINITION FROM SUBPART OOOOa TO BE USED WHEN FOLLOWING AN ALTERNATIVE APPROVED STATE PROGRAM, BUT EPA SHOULD NOT REQUIRE A DUPLICATIVE ADMINISTRATIVE BURDEN.

EPA could finalize a hybrid approach and require that, if an operator complies with an "approved" state LDAR program then the operator must follow the fugitive emission comment definition in Subpart OOOOa and assure that all components are included in the surveys (even if the fugitive emissions component definition in the state program is less expansive). However, there should be no reporting, recordkeeping or monitoring plan requirements as that is an administrative burden with no added environmental benefit and further defeats any benefit from EPA approving these state programs in the first place.

6.3 TYPOGRAPHICAL ERRORS WITHIN § 60.5399A

There appear to be typographical errors in the proposal rule regarding state program equivalency. Specifically, EPA appears to only approve Method 21 under Ohio's program; however, EPA's review memo included use of OGI as well. For Pennsylvania, EPA has listed GP-5 twice in the regulatory text. Well sites should be associated with GP-5a and compressor stations with GP-5.

Additionally, EPA only included the Texas Standard Permit but missed the Texas Non-rule Standard Permit³⁰. The Non-rule Standard Permit's LDAR provisions are similar to the Standard Permit. API requests that EPA add the Texas Non-rule Standard Permit to the approved State AMELs.

7.0 STORAGE VESSEL APPLICABILITY

API opposes the proposed changes to regulatory language regarding the determination of Subpart OOOOa applicability for storage vessels. EPA's proposed revisions to the storage vessel applicability language in § 60.5365a(e) and its proposed revisions for the definition of "*maximum average daily throughput*" results in a very impractical and inappropriate method for calculating and using the 30-day production applicability period. EPA's proposed revisions involve EPA in states agencies' authority to issue air permits containing legally and practically enforceable limits on VOC emissions from individual storage tanks and compromises Cooperative Federalism between EPA and state agencies. See: <https://www.epa.gov/home/cooperative-federalism-epa>: "*EPA is embracing cooperative federalism and working collaboratively with states, local government, and tribes to implement laws that protect human health and the environment, rather than dictating one-size-fits-all mandates from Washington.*" (*Emphasis added*).

7.1 TECHNICAL AND PRACTICAL ISSUES WITH THE PROPOSED REVISIONS TO DEFINITION OF "MAXIMUM AVERAGE DAILY THROUGHPUT"

EPA's proposed revised definition of "maximum daily average throughput" is not practical or appropriate. The proposed approach would frequently result in situations where the total emissions resulting from calculations to determine applicability can be multiple times what the actual emissions are for situations when more than one tank is present (which occurs in the vast majority of situations with new storage vessels). Specifically, for a situation where a site has produced fluids flowing to a group of "x number" storage vessels, it would be quite common to end up with emission estimates for individual storage vessels as well as the group as a whole that are "x number" times the actual emissions.

There are a number of different ways in which companies configure groups of tanks, but for the purposes of this discussion, let's focus on an example site with four (4) 400-barrel storage vessels where flow is being routed to one vessel at a time, until that vessel is full, and then to other vessels. If we assume that each vessel takes 7.5 days to fill, at the end of 30 days, we would have 4 full storage vessels containing a total of 1600 barrels of fluids. Applying EPA's proposed approach to this situation would mean that each storage vessel would need to estimate emissions assuming a flow rate of 400 barrels per 7.5 days or 53.3 bbl/day. With four storage vessels present and each calculating this way, EPA's proposed method would result in total emissions based on 53.3×4 , or 213.2 barrels per day of production, when the actual production rate is only 53.3 barrels per day. Of course, to obtain a correct "average production or throughput" the correct answer would be to divide the total 30-day production through each tank by 30 days ($400 \text{ barrels} \times 7.5 \text{ days} / 30 \text{ days} = 100 \text{ barrels}$).

³⁰ https://www.tceq.texas.gov/permitting/air/newsourcereview/chemical/oil_and_gas_sp.html

Additionally, most wells decline significantly over the first year at a rate of up to approximately 50 to 80 percent. Thus, the actual average emissions for the first year may only be an average of approximately 32 barrels per day when one considers production decline. With EPA's assumption in this case, production could be estimated as much as 6.6 times the actual production rate in the first year. Note that Section 7.5.2 of these comments also highlights that EPA is aware of the potential challenges when storage vessels are connected in parallel and has made efforts in the past to try to address this situation.

Additionally, when there are multiple controlled storage vessels at a site (as affected facilities under Subpart OOOOa or covered by a state permit or other limit), they are typically tied into a single control device. That is, the vapors from the collection of storage vessels are collected in a common manifold and routed together to a single emission point, the control device. This fact creates further inconsistency and challenges with EPA's proposed approach for determining applicability as the air emission source in a traditional sense has shifted from a single storage vessel to a single control device associated with a group of storage vessels.

API believes that even the current approach to determining emissions for applicability is conservative since operators must consider only the first 30 days of production, and there is no allowance for a reflection of the reality that production from wells declines over time, often very quickly. API also expects that there would be limited environmental benefit from the proposed change as most new storage vessels that receive oil or condensate are being installed with controls. This issue is discussed further in Section 7.2.

Perhaps for certain lower production scenarios or situations involving low volatility crude, EPA's proposed changes could result in the controlling of vessels that would not otherwise have had them. However, even in this scenario, there would be very low environmental benefit from the controls (due to the low actual emissions). Further, in all likelihood, a situation such as this would result in vessels that will have actual emissions < 4 TPY VOC after just the first 12 months of production. Thus, controls could be removed after just one year and would, in hindsight, prove to have not been cost effective in the first place.

7.1.1 EPA'S PROPOSED CHANGES ARE INCONSISTENT WITH POSITIONS TAKEN DURING THE ORIGINAL SUBPART OOOO RULEMAKING.

It is very difficult and impractical to measure throughput rates through individual storage vessels in a tank battery. EPA has recognized this in the preamble of the proposed Subpart OOOO rule, in proposed amendments to Subpart OOOO, and in EPA responses to public comments on those amendments. Provided below are two excerpts from EPA's Response to Comments document from the Subpart OOOO rulemaking. These excerpts clearly demonstrate that EPA has no intention to require the monitoring of flow to individual storage vessels under the rule. The proposed modifications to the definition of maximum average daily throughput in § 60.5430a certainly appear inconsistent with EPA's previously stated intent.

EPA Response to Public Comments, EPA-HQ-OAR-2010-0505-4546 (April 18, 2012), at 106-107 (Commenter 4178 – Laura Finley, ODEQ)

Comment: One commenter (4178) asserts that it is industry practice to not maintain records of the throughput of each individual tank; rather, total load out records are kept, which only show the total volume, rather than the volume at each individual tank. The commenter believes that

putting the mechanisms in place to be able to track the totals at each individual tank, in addition to the reporting requirements, could prove to be a great burden on industry.

Response: We do not believe that the concerns expressed by the commenter apply under the final rule. The final rule does not determine applicability based on throughput, nor does it require monitoring of throughput. Instead, operators are required to determine at the outset whether a new, modified or reconstructed storage vessel will have uncontrolled VOC emissions equal to or greater than 6 tpy and, if so, must install controls. The operator is not required to track VOC emissions thereafter.

EPA Response to Public Comments, EPA-HQ-OAR-2010-0505-4546 (April 18, 2012), at 126-127

Comment: Several commenters (3560/4258, 4192, 4219, 4228, 4241, 4246, 4266) object to the requirement in the proposed rule to use flow meters to determine the annual throughput of storage vessels...

Response: The final rule does not require the use of liquid throughput flow meters because the applicability of the storage vessel control requirements is determined based on annual VOC emissions, rather than liquid throughput as proposed. As discussed above and in section IX.E of the preamble to the final rule, we made this change in part because we are convinced that VOC emissions from stored fluids in the ONG industry are too variable to be regulated based on an average emission factor. Other factors in our decision to change the applicability metric include the issues raised by these commenters.

Recommendation:

EPA should review the previously stated comments by the Agency (noted above) and re-evaluate whether clarifications are actually needed to the rule regarding storage vessel applicability.

If there are changes ultimately made to the rule, the word maximum has always added confusion with respect to calculating the average daily throughput and should be removed. It is more appropriate that average daily throughput be represented as the total throughput to an individual storage vessel over the 30-day evaluation period specified in § 60.5365a(e)(1) divided by 30 days.

7.2 STORAGE VESSEL APPLICABILITY SHOULD BE OF LITTLE CONCERN WHEN EMISSIONS ARE CONTROLLED

Feedback from API members indicates that the vast majority of new storage vessel batteries currently being designed and installed are equipped with a control device. As long as an operator is controlling storage vessel emissions at well sites or central tank batteries in compliance with “a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority,” it matters little from an environmental perspective that the storage vessels are not subject to Subpart OOOOa compliance, recordkeeping and reporting requirements. In addition, states and operators have focused significant attention and resources to further address the appropriate sizing of storage vessel emissions control systems to ensure adequate handling of initial high production rates and peak flow from dump valves. It is also appropriate to note that, beyond general duty obligations that have always existed with respect to designing and maintaining equipment to minimize emissions,

when new storage vessels are added to a site, it is generally associated with the addition of wells to the site. In that scenario, the fugitive components associated with the closed vent system for the controlled storage vessels would be subject to the Subpart OOOOa fugitive component requirements.

7.3 RESTRICTIONS ON THE USE OF LEGALLY AND PRACTICALLY ENFORCEABLE LIMITS BY STATES, TRIBES, OR LOCAL AGENCIES VIOLATES THE CONCEPT OF COOPERATIVE FEDERALISM

EPA finalized effective rulemaking when it provided the original language in § 60.5395 that allowed an operator to use a legally and practically enforceable limit to keep its storage vessels out of Subpart OOOO. This resulted in the vast majority of new and modified well sites opting to take these limits and incentivized the installation of storage vessel emission controls long before the applicability date of Subpart OOOO. EPA's proposed revisions undermine this incentive and compromise cooperative federalism.

The benefits of this approach are similar to the benefits realized previously with respect to 40 C.F.R. part 63, Subparts HH and HHH, where companies can establish limitations on benzene emissions through enforceable permit conditions to maintain dehydrator operations below levels that trigger the MACT control requirements under those rules.

Additionally, EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to the Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. This has long been an effective approach to reduce recordkeeping burden while directionally reducing potential emissions – the same goal being met with the original Subpart OOOO/OOOOa language and approach.

7.4 HISTORY OF SUBPART OOOO STORAGE VESSEL APPLICABILITY LANGUAGE

A brief look at the history of how the storage vessel applicability methodology and rule language evolved, from the August 23, 2011 proposed Subpart OOOO rule to the June 3, 2016 final Subpart OOOOa rule, further demonstrates that the newly proposed amendments are impractical and unnecessary. Underlined wording is emphasis added.

7.4.1 AUGUST 23, 2011 PROPOSED SUBPART OOOO RULE AND AUGUST 16, 2012 FINAL OOOO RULE

In the original proposal for controlling VOC emissions from storage vessels, in § 60.5365, EPA exempted storage vessels for which either (1) the annual average condensate throughput is less than 1 barrel per day per storage vessel, or (2) the annual average crude oil throughput is less than 20 barrels per day per storage vessel. As explained in the Best System of Emission Reduction (BSER) analysis on pages 7-18 through 7-21 of the July 2011 Technical Support Document. EPA intended to exempt individual storage vessels with less than 6 TPY of VOC emissions. EPA attempted to simplify the applicability method for facility owners by applying a fixed VOC flash emissions factor of 33 lb VOC/bbl of condensate and 1.6 lb VOC/bbl of crude oil. However, public commenters, principally API, noted that the 33 lb VOC/bbl emissions factor was much too high for most condensates and was based on a very flawed storage tank emissions study conducted for TCEQ. It was also pointed out that condensate and crude oil

VOC flash emissions factors vary greatly from basin-to-basin and field-to-field due to the variability of last separator liquid API gravity, composition, temperature and, especially, pressure operating conditions.

EPA received many public comments regarding the costs and impracticability of measuring liquid flow rates to individual storage vessels. (See EPA's Response to Public Comments on Proposed Rule August 23, 2011 (FR 52738)). Therefore, in the August 16, 2012 final rule, EPA revised the storage tank applicability language to a basic VOC emissions determination. In § 60.5365 (a)(1), for well sites with no other wells in production, EPA stated that "...you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology within 30 days after startup...." In § 60.5395 (a)(2), for well sites with one or more wells already in production, EPA stated that "...you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology upon startup."

In the rule preamble on page 49498, EPA addressed the reasoning behind the revisions to storage vessel applicability stating "For storage vesselswith no wells already in production..., the final rule provides a 30-day period from startup for the owner or operator to determine whether the magnitude of VOC emissions from the storage vessel will be at least 6 TPY" and "For storage vessels at well sites with one or more wells already in production....these estimation and installation periods are not provided because an estimate of VOC emissions can be made using information on the liquid production characteristics of existing wells."

It is obvious EPA intended for the 30-day evaluation period to simply be a time period for determining each storage tank's potential annual VOC emissions using any generally accepted model or calculation methodology.

7.4.2 JULY 17, 2014 SUBPART OOOO RECONSIDERATION AMENDMENTS: PROPOSED RULE AND DECEMBER 31, 2014 FINAL RULE

The proposed amendments for storage vessels were simply to (1) amend the provisions for determining storage vessel PTE when vapor recovery is being used for control, (2) add closed cover requirements for other mechanisms besides weighted lid thief hatches, and (3) slightly amend the requirements for storage vessels to clarify notification and other requirements for storage vessels that are removed from service. To that end, EPA proposed adding a definition of "removed from service" to § 60.5430.

However, without any public notice or public comment period, in the final rule EPA introduced the concept of storage vessels being returned to service and possibly being operated in "parallel" with existing storage vessels and how that affects VOC PTE for the two storage vessels. EPA also introduced the concept of calculating VOC PTE based on "maximum average daily throughput for a 30-day period." In the preamble, EPA stated that "Although we believe it is an unlikely occurrence, we note that, when two or more storage vessels receive liquids in parallel, the total throughput is shared between or among the parallel vessels and, in turn, this causes the PTE of each vessel to be a fraction of the total PTE. In these cases, the EPA would consider the parallel storage vessels equivalent to a single vessel with PTE equal to the sum of the PTE of the individual vessels."

EPA revised the definition of *storage vessel* to include the language that "Two or more storage vessels connected in parallel are considered equivalent to a single storage with throughput equal to the total throughput of the storage vessels connected in parallel." EPA also, without any justification, added a definition for "*maximum average daily throughput*" to mean "the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods." EPA also

revised some of the storage vessel applicability language in § 60.5365 to include that “The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section.”

After publication of the final amendments in the Federal Register on December 31, 2014, numerous upstream and midstream O&G companies and trade groups raised concerns about the storage vessel applicability revisions to EPA for: (1) being made final without public notice and comment; and (2) for EPA making assumptions about the operation of storage vessels connected in parallel and/or series without any understanding of how the storage vessels may be operated in practice. Specifically, on February 19, 2015, the Gas Processors Association (GPA) submitted a petition for administrative reconsideration of the December 21, 2014 amendments. The GPA asserted that “it is quite common for multiple storage vessels to be situated next to each other and connected in parallel. Sometimes the storage vessels are operated in parallel, sometimes they are operated in series, and sometimes they are operated one-at-a-time with the connecting valves closed.” The GPA asserted this configuration has existed for decades and that “this language potentially has large impacts to how our members evaluate affected facility status.”

7.4.3 MARCH 23, 2015 OIL AND NATURAL GAS SECTOR: DEFINITIONS OF LOW PRESSURE GAS WELL AND STORAGE VESSEL: PROPOSED RULE AND AUGUST 12, 2015 FINAL RULE

In response to the concerns raised by numerous companies and trade groups including GPA in its petition for reconsideration regarding the finalized revisions to storage vessel applicability language, EPA proposed “to amend the NSPS to remove provisions concerning storage vessels connected or installed in parallel and to revise the definition of “storage vessel”. EPA discussed its original concern about storage vessels connected or installed in parallel in the proposed rule preamble and stated “For the reasons discussed above, we are proposing to remove the regulatory provisions relative to storage vessels ‘installed in parallel’ or ‘connected in parallel.’ Instead, we solicit comment on other approaches to help avoid or discourage installations or operation of storage vessels that would unnecessarily reduce the potential to emit (PTE) of a single storage vessel.” On August 12, 2015, EPA finalized the revisions as proposed.

On pages 14 – 20 of the July 2015 Response to Public Comments on Proposed Rule (80 FR 13180): March 23, 2015), EPA responded to a number of public comments that provide information on EPA ‘s rationale for removing the provisions concerning storage vessels connected or installed in parallel and revising the definition of “storage vessel.”

7.4.4 SEPTEMBER 18, 2015 PROPOSED REVISIONS TO SUBPART OOOO AND SUBPART OOOOa PROPOSAL

In this action, EPA kept the method of determining storage vessel applicability as it was for the final Subpart OOOO amendments.

By keeping the storage vessel applicability language as it was for the final Subpart OOOO amendments, EPA reaffirmed (1) the use of “legally and practically enforceable limits” and (2) no language was necessary to address any concerns with whether storage vessels are operated in series or parallel.

8.0 PNEUMATIC PUMPS

API supports EPA's proposed removal of the "greenfield" site designation and the associated proposed revisions that allow the technical infeasibility determination associated with the control of an affected pneumatic pump at all well site locations. We agree with EPA's determination that this designation should be removed. There are, however, additional technical clarifications related to the pneumatic pump requirements that EPA failed to address:

- Explicit clarification that heaters and boilers need not be considered as either a control device or as "routed to a process" with respect to the requirements in § 60.5393a for pneumatic pumps. This is especially important when reviewing revisions made to § 60.5412a and § 60.5413a with respect to control of centrifugal compressors and storage vessels using a heater or boiler.
- Simplification of the technical infeasibility assessment to account for situations that are common to operators, including situations when control devices are owned and operated by a third party or presence of only a high-pressure flare.

8.1 HEATERS AND BOILERS

EPA has not addressed API's request to clarify how to handle boilers and process heaters with respect to the requirements to control pneumatic pumps by routing to a process or a control device.³¹ By contrast, 40 CFR 63 Subpart HH and Subpart HHH include the following language under the definition of a "control device": *"For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or a closed-vent system."*

By not providing this clarity with respect to pneumatic pumps under Subpart OOOOa, operators must review the technical feasibility of routing pump exhaust emissions to any small heater or boiler added at the well site per § 60.5393a(b)(3)(i) and maintain additional records. For many heaters/boilers used at well sites, the burner capacity will be insufficient to compensate for emission combustion of additional pneumatic diaphragm pump discharge due to their small size, which is generally 0.5-1.25 million BTU/hour. This may result in frequent safety trips and burner flame instability (e.g., ., high temperature limit shutdowns, loss of flame signal, etc.). There are additional safety concerns due to the intermittent, pulsating exhaust of gas when the pump de-pressures because this can cause problems for the pilot or fuel system. Additionally, industry guidelines (i.e., NFPA 86) would prohibit the use of boilers/heaters as control devices based on specific criteria including minimum operating temperature and presence of

³¹ Under Subpart OOOOa, the provisions related to "control device" and "routed to a process" or "route to a process" are unclear with respect to controlling pneumatic pumps. These devices have additional requirements when controlling a storage vessel or wet seal centrifugal compressor that are not appropriate for the control of the intermittent emissions vented from a diaphragm pneumatic pumps.

emission source safety interlocks. Furthermore, small heaters and boilers are not inherently designed for control of emissions.

Consequently, boilers and heaters should not be considered “as routed to a process” nor as a control device with respect to the pneumatic pump requirements in § 60.5393a. We ask EPA to clearly provide this distinction under § 60.5393a(b)(3) to eliminate confusion with other requirements in the rule.³² This will reduce the overall administrative burden by removing the recordkeeping requirements specific to certification of the technical infeasibility of using a small heater at well site with respect to control of pump emissions.³³

Recommendation:

EPA should revise the rule language to clarify that, for the purposes of complying with the pneumatic pump provisions, heaters and boilers should not be considered as “routed to a process” or as a control device.

8.2 SIMPLIFICATION OF TECHNICAL INFEASIBILITY ASSESSMENTS

API submitted in our August 8, 2018 letter a request to simplify and reduce the administrative burden associated with conducting technical infeasibility assessments for situations that are pre-determined to meet the criteria listed in § 60.5393a(b)(5)(iii). If any of these situations were to occur at a well site with an affected pneumatic pump, operators would not be required to perform a full certification of infeasibility, but would document the cause of the infeasibility with respect to the common situations listed. This would alleviate undue burden associated with the technical infeasibility and certification requirements within this rule without posing any environmental dis-benefit.

- ***Exceedance of Maximum Rated Heat Capacity:*** The combustion device has a rated heat capacity that would be exceeded if the discharge of pump were to be sent to it.
- ***Operating pressure of the flare header exceeds the discharge pressure of the pump:*** If a high-pressure flare is installed to control emergency and maintenance blowdowns, it would not be technically feasible to route the low-pressure pump exhaust to the high-pressure flare because the operating pressure of the flare header exceeds the discharge pressure of the pump. For a flare to properly combust emissions and meet the destruction efficiency, the flare must be designed to manage either a high pressure or low pressure flow and for specific volumes being sent to it. A low-pressure exhaust would not adequately flow to the flare tip and result in inadequate

³² In § 60.5412a(a)(1) and (d)(1)(iv), states that introducing the vent stream into the flame zone of the boiler and heater would be using the boiler or heater as a control device. At the same time, § 60.5412a(a)(1)(iv) and (d)(1)(iv)(D), requires the vent stream to be introduced with the primary fuel or use the vent stream as a primary fuel which would be routing the stream to a process. EPA has two conflicting requirements together in the same section. Inferring from the revisions in this proposal, EPA appears to distinguish the issue of whether a boiler/heater is a control or process device by where the vent stream to be combusted is placed. In § 60.5413a(a)(3)), boilers/heaters are exempt from testing requirements if the vent stream is tied into the primary fuel or is the primary fuel for the heater firebox. This exemption indicates that EPA treats boilers/heaters as a process device. Conversely, if the vent stream is directed at the flame zone, then the boiler/heater appears to be considered a control device under the rule per § 60.5412a(a)(1) and (d)(1)(iv).

³³ If EPA continues to intend heaters and boilers be considered for reducing emissions from diaphragm pneumatic pumps, heaters and boilers should only be considered as process devices, which is inherent of their operational use; with additional provisions streamlining the technical infeasibility assessment.

combustion of the exhaust. A separate flare would have to be installed to route the low-pressure exhaust from the pump which would not be cost-effective to install, as demonstrated in EPA's Regulatory Impact Analysis.

- ***Existing third-party control device on location:*** A company cannot legally route pump exhaust emissions to an existing third-party control device at a site. In addition, since the control device owner designs the equipment, the pump owner could not attempt to certify that the control device owned or operated by a third party is of sufficient design and capacity as specified in the certification requirements under § 60.5411a(d)(1). This is less likely to be an issue when a site location is being originally designed, but presents issues for existing locations where a new diaphragm pneumatic pump may be installed. Some examples of third-party control devices that an owner or operator of the pump could not route to include:
 - *Gathering Company Dehydration Unit Flare:* In some instances, a control device for the dehydration unit on a production site may be owned and operated by a gathering and collection system operator. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.
 - *Reboiler for Dehydration Unit:* The reboiler for glycol dehydration unit and the dehydration unit may be owned or operated by the gathering company while the pump is owned by the production company. The production site owner would not have authority to route a pump to the dehydration unit reboiler.
 - *NGL Recovery Unit Flare:* There are instances where a natural gas liquids (NGL) recovery unit with a flare are owned by a third party, such as a gathering company, that is located at a production site with a pump that is owned by the production company.
- ***Presence of Small Boiler or Small Process Heater:*** Comment 8.1 outlines technical challenges with use of boilers and heaters with respect to control of a pneumatic pump. If EPA does not provide clarification for handling boilers and heaters with respect to control of pneumatic pumps, then simplification of the technical infeasibility assessment must be provided based on the stated technical considerations.

Recommendation:

EPA should reduce the administrative burden associated with conducting technical infeasibility assessments for situations that are pre-determined to meet the criteria listed in § 60.5393a(b)(5)(iii). Any of the following situations should be considered to represent common technically infeasible situations and such situations should not require further assessment: (1) Flare or other combustion device has a rated heat capacity that would be exceeded if the discharge of pump were to be routed to it; (2) Operating pressure of the flare header exceeds the discharge pressure of the pump; and (3) The control device is not owned and operated by the owner/operator of the pneumatic pump.

8.3 THE 90-DAY EXEMPTION BASED ON CALENDAR DAYS SHOULD ALSO ALLOW FOR 2,160 HOURS OF OPERATION IN § 60.5365A(H)(2)

API requests the use of a non-resettable run-time meter or automation to track hours of operation of a pneumatic pump to demonstrate that pumps that operate only occasionally operate less than 2,160 hours in addition to the current 90-day exemption. Allowing the use of a run-time meter or other automation to demonstrate operation below 2,160 hours per year would allow greater flexibility in documentation and

better compliance demonstration that the pump runs less than 90 days a year. There are a number of pumps that might run for less than an hour every day or two, such as a water transfer pump. Such a pump would have very low annual emissions yet could still trigger the rule under the current language due to the nature of its operation.

EPA should maintain the current 90-day exemption in addition to this option. To be clear, 2,160 hours is the equivalent timing of a pneumatic to a pump that operates 24 hours per day for 90 days. EPA's background documentation established the 90-day exemption assuming 24 hours of operation of a pump based on a pump emission rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document).

8.4 CROSS REFERENCE ISSUES IDENTIFIED FOR PNEUMATIC PUMP CLOSED VENT SYSTEM REQUIREMENTS

Although dependent on how pneumatic pump closed vent systems are handled in the final revision to Subpart OOOOa, API notes that there are numerous issues with the references to the closed vent system requirements proposed by EPA, including:

- There are no references to § 60.5415a and § 60.5416a found in § 60.5393a. Only § 60.5410a, §§ 60.5411a, and 60.5420a are referenced in 60.5393a and these sections do not reference 60.5415a or 60.5416a. This is very confusing because operators subject to pumps may not read these sections to know that they are subject to them if that, in fact, is EPA's intent.
- § 60.5415a(b) references both pumps and centrifugal compressors though the reporting requirements in § 60.5415a(b)(3) which include requirements that only apply to centrifugal compressors [including § 60.5420a(b)(3), § 60.5420a(c)(2), (7), (9), (10), and (11)]. API recommends that pneumatic pumps be split from centrifugal compressors in this section to make it clear the applicable reporting and recordkeeping requirements that apply to pneumatic pumps. Pneumatic pumps should only be subject to § 60.5420a(b)(1) and (8) and § 60.5420a(c)(6), (8), (16), and (17).
- Though it may be an oversight, § 60.5416a(b) still includes pneumatic pumps for the requirement to do Method 21 monitoring of the closed vent systems.
- Under § 60.5416a(c)(2), EPA has included reference to pneumatic pumps in the cover requirements listed in § 60.5416a(c)(2), although pumps do not have covers and are not subject to the cover requirements under § 60.5411a(b). We believe this is a cross-reference typographical error.
- There is no date upon which § 60.5416a(a) and (b) no longer apply and § 60.5416a(c) applies to the closed vent systems of pneumatic pumps. Therefore, it is unclear for operators whether or not sites already subject should change inspection methods for the closed vent system or keep using the existing method. Clear dates should be incorporated in the rule stating that it applies to existing Subpart OOOOa pumps and new as of publication of the proposal on October 15, 2018. EPA should also consider additional flexibility of assurance for pump CVS as discussed in Comment 10.0.

9.0 CERTIFICATION BY AN IN-HOUSE ENGINEER OR QUALIFIED PROFESSIONAL ENGINEER

9.1 IN-HOUSE ENGINEER OR QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION CHANGES

API supports changing the requirement to require a qualified professional engineer for the CVS certification but the proposed changes to the rule to allow the use of an in-house engineer for certification still result in costs and difficulties in certifying:

- The technical infeasibility for routing pneumatic diaphragm pumps to a control device or process under § 60.5393a(b)(5), and
- The closed vent system (CVS) under § 60.5411(d)(1) for centrifugal compressor well seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

Some challenges that will remain even with allowing an in-house engineer include the following:

- EPA has not defined in-house engineer, as to whether the engineer must be a full-time employee or could be a consultant working “in-house” for the company.
- Most in-house engineers and Professional Engineers (PE’s) are not bonded and insured, thus are not willing to certify that they are “*aware there are penalties for knowingly submitting false information.*” Some engineers fear that this statement could result in prosecution of individuals versus the company or the responsible official certifying the entire report.
- If an engineer (PE or in-house) did not design the whole system, they are unwilling to certify the CVS system. The new amendments are still not adequate.
- EPA underestimated the cost for an engineering certification as detailed in Comment 9.2

As stated in our December 8, 2017 letter to EPA, API maintains that a technical assessment of a closed vent system by a qualified engineer is an appropriate action for compliance assurance of the emission standards for storage vessels, compressors and pneumatic pumps. Documentation of this technical assessment should provide adequate compliance assurance that can be made available upon request to EPA. EPA should remove the certification statement in § 60.5411(d)(1)(i). The certification requirement and specific certification language that EPA includes in § 60.5411(d)(1)(i) presents numerous challenges and unintended costs beyond what EPA considered during this proposal. The certification process and statement itself does not add significant environmental benefit nor additional compliance assurance since there are provisions in place for ongoing compliance specific to the operation of closed vent systems, a general duty for all operators to minimize environmental impacts, and the annual report must be approved by a certifying official.

- There is already a ‘general duty obligation’ in § 60.11(d) for owners and operators to ensure proper operation and maintenance of equipment. The engineering certification statement does not relieve companies of this duty.
- The certifying official is already required to sign the report certifying the company’s compliance with all applicable provisions.
- There are direct costs associated with the engineer certification process, whether companies support in-house licensure of engineers or leverage third parties.

- Engineering documentation showing that the closed vent system was properly designed or that a control was technically infeasible as part of the recordkeeping requirements should provide adequate compliance assurance. These records can be made available by request to the Administrator, as necessary.

Recommendation:

EPA should eliminate the certification statement in § 60.5411(d)(1)(i). If EPA retains the certification statement within the technical assessment, we request EPA should replace the descriptor of “in-house” to allow an engineer with knowledge/oversight of the system design. EPA should review the certification language with respect to liabilities for the engineer providing the assessment. The certifying official is already required to attest to their company’s compliance with all applicable provisions. Any inclusion of discussion of liabilities for the engineer themselves only confuses EPA’s intent that a professional engineer is not required.

9.2 EPA UNDERESTIMATED THE COST OF AN ENGINEERING CERTIFICATION

API members report costs ranging from \$2,000 - \$9,000 per certification; with actual cost dependent on the site complexity and, thus the amount of engineering design time involved. EPA estimates each certification by a professional engineer would cost only \$547 and an in-house engineer would cost only \$358. These costs are based on only four hours of staff level engineer time for the in-house engineer and on only two hours of work by a professional engineer. This level of cost does not match the inherent time required to have knowledge of the system prior to the certification; especially given the language and liability included within the certification language.

10.0 CLOSED VENT SYSTEM AND COVER REQUIREMENTS

API appreciates that EPA has made efforts to propose changes to the pneumatic pump closed vent system requirements versus requiring annual Method 21 inspections of the pump closed vent system. EPA has proposed to align pneumatic pump CVS inspections with the requirements for storage vessel CVS inspection. API has discussed different approaches to the pump CVS requirements with EPA and would like to clarify our position.

- API request EPA further increase flexibility pertaining to the closed vent system requirements for pneumatic pumps by allowing the option to perform monthly AVO inspections or allow annual OGI or Method 21 inspections.
- API requests simplification of the recordkeeping and reporting requirements for the CVS inspections. Consistent with our position on other recordkeeping and reporting, EPA should focus on the most important elements and not require data that does not provide direct value.

10.1 EPA SHOULD INCREASE FLEXIBILITY IN PNEUMATIC PUMP CLOSED VENT SYSTEM INSPECTIONS

Unlike closed vent systems that are used to route storage vessels to a control device, a closed vent system with respect to control of pneumatic pump emissions is simply a hard piece of pipe with connectors or

flanges. While the technical feasibility of routing pneumatic pump emissions to a control device presents many technical challenges, as described in previous comments, once the pump is routed to a control device through a closed vent system, the closed vent system itself is fairly simple in design. Given the simplicity and low potential for leaks or defects along the piping, EPA could and should allow increased flexibility in implementation of the no-detectable emission limit along this piece of pipe by allowing multiple options to perform inspections including monthly AVO, annual OGI, or annual Method 21. EPA has considered OGI an equivalent method under the leak detection and repair requirements and the hard piping of the closed vent system for the pump for defects can be performed the same as looking at fugitive components.

Practically speaking, for sites where monthly AVO is being performed on an affected storage vessel, many companies would prefer to do monthly AVO. For sites subject to Subpart OOOOa leak requirements and no Subpart OOOOa storage vessels, companies are more likely to prefer to conduct annual OGI inspection.

Recommendation:

EPA should further increase flexibility pertaining to the closed vent system requirements for pneumatic pumps by allowing the option to perform monthly AVO inspections or allow annual OGI or Method 21 inspections.

10.2 SIMPLIFY RECORDKEEPING AND REPORTING FROM MONTHLY AVO

EPA is requiring that operators collect and report a great amount of information for closed vent system AVO inspections. This data collection increases the time that it takes to do these inspections and increases burden of such inspections without providing a clear environmental benefit. API requests that the reporting requirements for both storage vessels (in § 60.5420a(b)(6)(ix)) and pumps (in § 60.5420a(b)(8)(iv)) be eliminated and not finalized as proposed.

API requests that the recordkeeping requirements be further simplified, consistent with previous comments, and limited to the following:

- Site ID
- Date of the inspection;
- Number and type of defects identified;
- Number and type of defects that were not repaired as required; and
- Number and type of defects placed on delay of repair and explanation for each delay of repair.

API also requests that EPA remove the requirements for recordkeeping under § 60.5420a(c)(6), (7) & (8) and reporting under § 60.5420a(b)(8)(iv) for pumps for covers because pneumatic pumps do not have covers and are not subject to § 60.5411a(b). We believe this is likely a typographical error in the proposed rule.

11.0 WELL COMPLETIONS OPERATIONS

11.1 API SUPPORTS CLARIFICATIONS REGARDING SEPARATOR LOCATION AND DEFINITION OF FLOWBACK; SEEKING ADDITIONAL CLARITY IN PROPOSED DEFINITIONS

We support EPA's proposed clarifications regarding well completion operations in § 60.5375a(a)(1)(iii) that explicitly allow use of nearby separators during flowback and provide the distinction that certain activities that occur prior to flowback including screenouts, plug drill outs and coil tubing cleanouts are not intended to be part of flowback as defined. There are additional minor clarifications required with respect to the newly proposed definitions for these activities as follows:

- *Coil Tubing Cleanouts* include mechanical methods to remove solids and/or debris from a wellbore. The process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface.
- *Plug Drill-outs* are the removal of a plug (or plugs) that were used to isolate different sections of the well.
- *Screenouts* are attempts to clear proppant from the wellbore in order to carry the proppant out of the well.

11.2 PROPOSED DEFINITION OF PERMANENT SEPARATOR

In § 60.5420(b)(2) and (c)(1), EPA introduces the term "*permanent separator*." The definition EPA provides in § 60.5430a for "*permanent separator*" describes temporary actions, which is contrary to the inherent meaning of the word permanent. Specifically, EPA defines the usage of the permanent separator as handling flowback between the initial flowback period and the startup of production, which is temporary in nature.

Recommendation:

To mitigate confusion on the flowback requirements, API suggests not finalizing the proposed definition of permanent separator and removing reference of the term for purposes of recordkeeping and reporting § 60.5420(b)(2) and (c)(1). The completion log requirements would not require a separate category since the daily log includes the time period described in this definition.

11.3 RECORDKEEPING AND REPORTING FOR COMPLETION OPERATIONS THAT IMMEDIATELY START PRODUCTION SHOULD BE SIMPLIFIED

In some locations, operators are able to start production immediately following well cleanup activities. In these cases, the flowback period, including both the initial flowback stage and separation flowback stages as defined in § 60.5430a, is bypassed and the well immediately starts production following well cleanup activities. For wells where it is possible to immediately start up production, we request simplification of the recordkeeping and reporting burden associated with maintaining the daily completion log. The simplification of these records is requested to reduce administrative burden since the daily completion log information is not relevant after startup of production.

Recommendation:

For well completions operations that immediately start production, API recommends that EPA only require the following for recordkeeping and reporting: 1) the United States Well Number, 2) the Well Completion ID, 3) Identification that the well immediately starts production (i.e. there is no initial flowback stage or separation flowback stage), 4) the date of startup of production (in lieu of Date of Onset of Flowback Following Hydraulic Fracturing or Refracturing).

12.0 OTHER TOPICS**12.1 THE EQUATION DEFINED FOR CAPITAL EXPENSE REMAINS UNREPRESENTATIVE OF CURRENT ECONOMIC CONDITIONS.**

API believes that the definition of Capital Expenditure (and the equation listed in Subpart OOOOa) is unrepresentative of current economic conditions. It was meant to model inflation in the late 1970s and early 1980s, as stated in EPA-FR-1984-Vol 49 No 105, P 22603. API requests that EPA utilize a ratio of Consumer Price Indices (CPI), as noted in our original comments and as used in the “Civil Monetary Penalty Inflation Adjustment Rule” published in the Federal Register on July 1, 2016 and located at <http://federalregister.gov/a/2016-15411>. As we stated in our December 4, 2015 comments, the equation proposed by the EPA unrepresentatively overstates the effect of inflation in terms of discounting the value of B. We maintain that a Consumer Price Index (CPI) based equation is more appropriate for use in discounting inflation in current economic conditions.³⁴ API proposes that EPA use a CPI based equation to discount B (valued at 4.5% for our industry) as shown: $Y = (\text{CPI of date of construction or reconstruction} / \text{CPI of date of component price data})$.

An example of the effect of the improper use of inflation is that gas plants that are built after 1982 trigger “modification” with as little as a single valve added to the process unit. Many times these process units may require large replacements of “equipment” (as defined in the regulation) to comply with this change and permanent plant shutdowns may occur as a result because these replacements are uneconomic.

We incorporate by reference the following docket previously submitted to EPA by GPA on this issue. <https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7237> (page 42).

³⁴ Refer to Comment 16 in API’s December 4, 2015 Comment letter at EPA-HQ-OAR-2010-0505-6884

Attachment A
API's Response to EPA's Analysis of Well Site
Fugitive Emissions Monitoring Data

API's Response to EPA's Analysis of Well Site Fugitive Emissions Monitoring Data

Memo dated April 17, 2018
EPA-HQ-OAR-2017-0483-0036

EPA released a memo summarizing the Agency's review and analysis of the leak detection and repair (LDAR) data submitted by API in early 2018 (see Docket: EPA-HQ-OAR-2017-0483). EPA's memo discusses their view of data uncertainty associated with the data provided and presents EPA's rationale for why these uncertainties contribute to the inability of EPA to rely on the data directly with respect to the current proposed amendments. API members collected leak detection data from over 4,000 well sites across the country and submitted these data to help the Agency better understand trends with actual leak incidence occurring at well sites. API believes EPA's analysis and conclusion that the data cannot be relied upon is flawed for several reasons as detailed below by topic.

Additionally, the tone and content of EPA's memo suggest inherent bias by the agency. That is, the Agency's analysis implies that there must be flaws in the dataset as the results represented lower leak rates than EPA appears to have expected. This inference is particularly concerning as no data or explanation for EPA's expectations are provided. The data relied upon by EPA in developing its estimates for leaks from well sites comes from the 1995 EPA Leak Protocol document where values based on a small sample size of oil and gas operations. The 1995 Protocol was also derived from oil and gas facilities whose designs are expected to be significantly different than modern sites subject to Subpart OOOOa.

A. EPA Concern with Uncertainty of Well Site Age

Summary of Issue: EPA's stated concern is that the dataset did not provide the age of the wells. EPA asserts new wells *"could be expected to have a lower-than average incidence of fugitive emissions because components have not yet experienced degradation via wear and tear or lack of maintenance."*

API Response: API does not agree with EPA's assertion, but more importantly, we do not understand how this is a limitation to the data provided. By nature, New Source Performance Standards, like Subpart OOOOa, are directed at new and modified sources. Our dataset was focused on providing the initial leak incidence rates being observed by members at the type of facilities that EPA has regulated under Subpart OOOOa.

If EPA truly believes new well sites are expected to have lower than average leak incidence, this would directly conflict with EPA's reasoning for requiring new sources to perform leak detection within 60 days of startup. We would further question how EPA has estimated the baseline emissions for new well sites within their cost-effectiveness analysis since the model plants do not distinguish between new and modified locations. Furthermore, by EPA's logic, any inclusion of older wells undergoing the first OGI survey in API's dataset would only provide a higher than "average" initial leak incidence than a collection of only new wells. This would infer API's data is conservative with respect to types of well sites subject to the NSPS.

B. EPA Concern with Uncertainty of OGI Procedures and Environmental Conditions During Surveys

Summary of Issue: EPA expresses concern about the specific methods used in conjunction with the OGI surveys that led to the API dataset and concludes: *“Without standardization of monitoring procedures, or knowledge of which programs this initial monitoring was conducted under, it is not possible to determine the quality of the monitoring data and whether the survey operator accounted for environmental conditions and interferences during the survey.”*

API Response: It seems EPA is expecting wide variability in the environmental conditions when OGI is used and thus, even though this dataset is large, such variability is so great that the average of the data is not useful. API believes this position is unreasonable and overly pessimistic with respect to the ability to use OGI instruments. While API appreciates the potential variability between equipment and the exact methods used in conjunction with the OGI camera, many of the survey data provided were collected under compliance obligations, either under Subpart OOOOa directly and/or another state program. API also believes that the dataset is quite large and covers many geographies and operators and is superior to the small dataset behind the 1995 EPA leak protocol document. Furthermore, it is difficult to understand how EPA can make these statements with respect to the OGI data provided by API and, in the same proposed rulemaking, rely upon OGI data collected through a helicopter survey in order to make assumptions specific to thief hatches and pressure relief valves.

With respect to environmental conditions and interferences, EPA states that lack of knowledge on wind speed and weather conditions effectively limits the use of the data provided. First, not all state programs have required capturing this type of information and therefore, it does not exist for some of the survey data. Perhaps more importantly, while API understands that Subpart OOOOa requires capturing this information, the fact is that EPA does not have any quantifiable method to include or exclude data based on it. Therefore, the assertion that the data cannot be used because the wind speed and weather condition information is missing is unreasonable.

While certain conditions, such as high wind speed, can make it more difficult to identify small leaks, operators are unlikely to perform surveys during high winds (and other limiting conditions). API believes it is also important to acknowledge that study after study shows that the majority of emissions come from the largest leaks. Even if one were to accept EPA’s inference that some small leaks were missed during surveys, the mass of such leaks would have little impact on the overall expected emissions.

Lastly, industry has invested extensive resources in the use of OGI cameras. The cost to implement a leak detection and repair program is not insignificant. It is impractical to assume that companies are not properly using the technology after making such high investments in equipment and manpower.

C. EPA Concern with Uncertainty of Universe of Components Monitored

Summary of Issue: EPA expressed concern about whether or not all the components covered by Subpart OOOOa were surveyed since not all surveys were performed under the NSPS.

API Response: API member companies indicate that their staff and contractors generally make a record of all leaks identified during OGI surveys. Reasons for this include:

- A desire to not confuse staff completing the surveys with regard to what components are to be surveyed under different regulatory programs, and operators want to get the maximum benefit of mobilization for a given survey.
- Companies want to know that identified leaks are repaired to capture the natural gas for sales.

API believes that the universe of components in our dataset is, on average, more exhaustive than the components covered by Subpart OOOOa. Additionally, EPA’s concern about the universe of components that are monitored may be coming from a different industry context. For example, a refinery or chemical plant will have components and entire sections of facilities that are not subject to LDAR under federal regulations. This is because certain streams may be low in VOC content and, therefore, are not subject to monitoring. For oil and gas well sites and compressor stations, there is no such applicability criteria. This means all the components at a well site or compressor station are subject to the leak survey. While closed vent systems under Subpart OOOOa undergo separate compliance measures through implementation of separate inspections, operators do not typically distinguish these components separately when using the OGI for reasons stated above, i.e. operators seek maximum benefit for conducting leak surveys.

D. EPA Concern with Uncertainty of Production Rates of Well Sites

Summary of Issue: There is no information provided on the production rates of the well sites included in the dataset and EPA did not want to misapply the data.

API Response: Production data are not easily associated with leak data based on the recordkeeping associated with leak detection surveys. In the absence of information on wells that are low production, we assumed all well sites in our dataset produce more than 15 barrels of oil equivalent per day.

E. EPA Concern with Uncertainty of Equipment Counts

Summary of Issue 1: EPA expressed concern about the accuracy of API’s data, stating: *“Of the 4,117 well sites included in the dataset, only 95 of these well sites had known equipment counts. Equipment counts for the remaining 4,022 well sites were estimated using the default average component counts for onshore natural gas and crude oil production equipment listed in 40 CFR part 98, subpart W, Tables W-1B and W-1C.”*

EPA goes on to state: *“Additionally, the counts in subpart W do not accurately reflect the entire universe of components that could be present at a well site. For example, for natural gas production equipment, Table W1B only lists estimated counts for valves, connectors, open-ended lines, and pressure relief devices on wellheads, separators, piping, compressors, heaters, and dehydrators. It does not include sources like storage vessels, where thief hatches would be a potential source of fugitive emissions.”*

API Response to Issue 1: API is concerned by EPA’s logic on the use of estimating components in the above statements for several reasons:

- 1) EPA has mis-categorized the data. There were 95 well sites that had a known level of actual components stated. We believe this was a typo in the memo. As EPA states, the additional 4,022 sites used known equipment counts to estimate the number of components using a

generally accepted approach that EPA has established under the Greenhouse Gas Reporting Program at 40 C.F.R. part 98, Subpart W.

- 2) The component count methodology under Subpart W have been the basis for the GHG reporting rule for several years, so it seems inappropriate for EPA to assert that the methodology is inadequate in estimating number of fugitive components.
- 3) While EPA infers it was inappropriate for API to use these Subpart W component factors in our analysis, these are the same component factors EPA uses in the development of the model plant. We fail to understand how our application of these factors in estimating components based on known equipment at our well sites is different than EPA's methodology of establishing the number of components at the model plants using the same factors.
- 4) By EPA's stated example, the component counts provided in our dataset are estimated lower than what EPA feels might be representative, indicating our data were conservative. In other words, the leak incidence values in the dataset would be even lower when these additional components are added to each well site; in addition to the Subpart W factors already estimated.
- 5) We reviewed the average components based on the actual equipment listed in our data compared to the average number of components EPA had used during the final rulemaking in Subpart OOOOa (which were available during the time the API data was compiled). While our data show slightly higher components for Oil Wells Associated with Gas, our gas well sites contain, on average, about 100 less components than EPA's gas well site model plant for the final rulemaking.

We also note that EPA has reduced the number of estimated component counts in their newly released model plant for both gas well and oil well sites. This directly conflicts with EPA's stated concerns that our dataset had underestimated the total number of components with respect to estimating the leak incidence.

EPA Model Plant Categories in Final Rule	EPA Model Plant Components in Final Rule	Average Components from API Data	Model Plant Counts in Proposed Rulemaking
Gas Well Sites	671	580	610
Oil Well Sites (GOR < 300)	127	Not applicable, data only include light crude oil wells with associated gas.	127
Oil Well w/ Associated Gas (GOR > 300)	314	347	257

Summary of Issue 2: *“An estimated component count will likely bias the leak rate, as the leak rate is directly correlated to the number of components present and monitored. Whether the leak rate is biased high or low would depend on whether the fugitive components are over or under estimated.”*

API Response to Issue 2: We agree the total number of components at the site is an important factor when considering the overall leak incidence rate. In this context, a site with only 40 total estimated components should not be equally compared to a location with 1,000 estimated total components. To account for this variation, we applied a weighted average to specifically account for the number of total components estimated at the site. We continue to maintain that this was a correct approach and one that directly addresses the variation and uncertainty in using estimated component factors. We discuss this more in our response to EPA’s concerns with the calculated leak rates.

Summary of Issue 3: EPA states, *“Furthermore, because the equipment counts do not include components like thief hatches, it calls into question whether these types of components were monitored during the surveys. As previously discussed, the presented information is limited as to whether the universe of fugitive emissions components required under the 2016 NSPS OOOOa were monitored during the surveys, potentially biasing the leak rates; the equipment counts further reinforce this concern.”*

API Response to Issue 3: As discussed in API’s response to Section C above, the assertion that API members are not surveying all potential fugitive components is unfounded and is simply inaccurate. Further, the methodology used to determine an estimate of total components at a well site does not influence or impact the number or type of leaking components identified within the leak records. For EPA to make any linkage or assumption between the approach to estimate the number of components and the count of leaks identified is unfounded. Our analysis included review of records maintained when conducting initial leak surveys at 4,117 well sites. We then paired this information with separate records that describe the number and type of equipment located at these well sites. Information regarding equipment to estimate the number of components of these sites based on an approach developed by EPA to estimate fugitive components. This was a large undertaking by member companies to collect and organize data in order to present information in, what was believed to be, a useful format for the Agency.

F. EPA’s Concern with the Uncertainty of Zero-leak Rates

Summary of Issue: EPA claims the dataset contained an unusual number of well sites reporting no fugitive emissions during the monitoring surveys. *“Of the 4,117 well sites, 44% reported no fugitive emissions. This extremely high percentage of well sites with a zero-leak rate reinforces concerns related to the proper use of OGI and the need for standardization in the way that OGI is performed in monitoring surveys, as previously discussed.”*

API Response: EPA asserts the zero-leak findings in our data are unusually high but does not present any basis for this claim. Our data is based on real world results of implementing leak detection and repair program at well sites which are indicative of the locations subject to the NSPS. We have submitted multiple rounds of data in various formats that continue to show this similar trend. These statements are troublesome as they express a level of bias by the Agency with respect to our operations and have no supporting merit for comparison. We also disagree that more stringent standardization of OGI procedures would show different results. Each monitoring survey is conducted to ensure all components are surveyed. EPA continues to erroneously equate the sources at well sites and compressor stations covered under

Subpart OOOOa with sources covered by traditional LDAR programs such as chemical plants and refineries, which are large, complex facilities containing tens of thousands or more components. These facilities require a team of full-time dedicated staff on-site to manage the significant demands associated with running a “traditional LDAR” program. This is very different from managing surveys containing a relatively small number of total components at hundreds (and eventually thousands) of un-manned, remote production facilities.

G. EPA’s Concern with Leak Rates

Summary of Issue 1: EPA believes a weighted average does not address the average leak rate at individual well sites.

API Response: By definition, a weighted average is similar to a straight average except that instead of each of the data points contributing equally to the final average some data points contribute more than others. As we discuss above, we believe variation in the total number of components at the well site is an important factor to be considered when reviewing the leak incidence in appropriate context. In fact, we have previously submitted comments asking that sites with less components than what EPA estimates in the model plant be exempt from leak detection programs because of this issue.

Some specific points about our data based on statements by EPA:

- There was one state, Ohio, where out of 37 locations surveyed, no leaks were identified. First, we point out that the Pennsylvanian Basin (Eastern Overthrust Area) includes portions of Ohio. EPA should consider that some Pennsylvania Basin wells may be located in Ohio and review the data in its entirety. Second, all of these locations were identified as single gas well sites containing separators, heaters and some piping. These locations each have an estimated total components count less than 200. Based on the equipment located at these sites, we do not find it unreasonable to assume no leaks were found based on the equipment identified. Lastly, we continue to point out that operations at well sites are vastly different than what EPA might expect at larger, more complex facilities.
- Well sites in Alaska average around 30 wells per well site compared to EPA’s model plant of only two wells. The total component counts we estimated at these well sites are, therefore, likely underestimated for these assets. This means the leak incidence calculated for these locations is overly conservative in its estimation.

Summary of Issue 2: EPA states a 1.18% leak incidence was assumed at well sites.

API Response: EPA assumed that 1.18% percent of components, or four components, were leaking in order to estimate the count of components that would require repair. With respect to quantification of baseline emissions, EPA applied emission factors to the population of components within the model plant, i.e. the emission factor was multiplied against all components at the well site. That is, EPA did not estimate baseline emissions assuming only four components leak at the site. It is misleading for EPA to continue to make erroneous statements with respect to the number of leaks assumed in their analysis and their associated emissions.

Figures 5-16 through 5-34 of the EPA Leak Protocol clearly demonstrate that the emission factors within Table 2-4 correspond to a specific fraction (or number) of components that are assumed to be leaking. To

make this point clear, Figure 5-25 from EPA Leak Protocol is provided below for reference and depicts this correlation between emission rates and leak incidence rates.

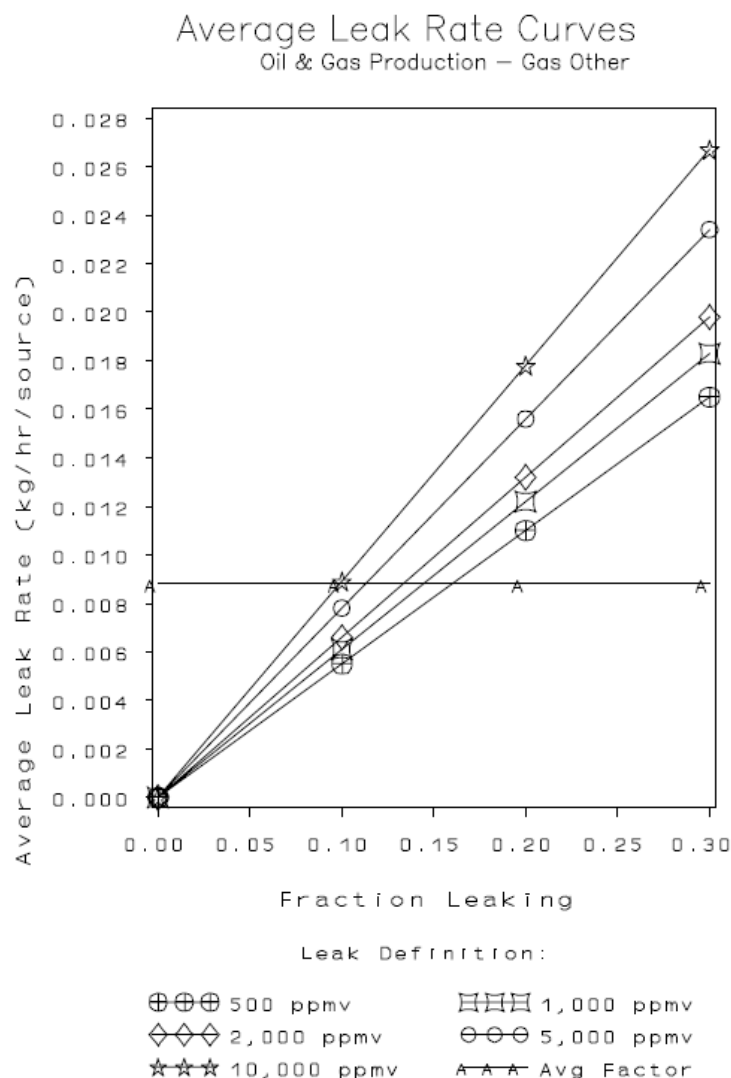


Figure 5-25. Oil and Gas Production Gas Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

As Figure 5-25 clearly depicts, the average leak factor from Table 2-4 for “other” equipment at gas production sites is 8.83 E-03 kg/hr/source, as demarcated by the horizontal line. This emission rate directly corresponds to a fraction of leaking components that ranges from nearly 0.1 to 0.16 (or 10 to 16%) of “other” components, depending on the leak definition applied. Similarly, one can look at the Figures in Chapter 5 of the EPA Leak Protocol and determine the fraction of all component types that are assumed to be leaking when one uses the Table 2-4 factors to represent a population of components. Each component type (connectors, flanges, open-ended lines, etc.) has a different assumed leak fraction embedded within the average emission factor rate.

The following table summarizes the fraction of leaking components assumed within the Table 2-4 Emission Factors based on a leak definition of 500 ppm and 10,000 ppm.

Type of Component	Original EPA Basis for Emissions from Leaks (Table 2-4): (kg/hr/comp) ¹	Percent of Components Leaking @500 ppm using Table 5-7 correlations	Fraction of Components Leaking @10,000 ppm using Table 5-7 correlations
Valves	0.0045	6.42%	4.57%
Flanges	0.00039	0.90%	0.47%
Connectors	0.0002	1.20%	0.73%
OEL	0.002	5.39%	3.61%
PRV	0.0088	15.97%	9.75%

Using the figures and correlation equations within the EPA leak protocol, one can calculate that, for the EPA model facility assumed in the 2016 Subpart OOOOa rulemaking, EPA actually assumed between 1.6% and 2.5% of components at a model well site were leaking, depending on the leak threshold used to define the leak. The lower value represents an assumed 10,000 ppm Method 21 leak definition and the higher value assumes a 500 ppm leak definition, which is the leak definition finalized within Subpart OOOOa.

We also note that the analysis EPA developed in support of the 2018 Subpart OOOOa proposal for thief hatches follows a similar process to arrive at a new emission factor. The new emission factor for thief hatches is based on newly available data, and similar to the Table 2-4 factors, the newly proposed emission factor represents yet another assumed leak fraction for that particular component type.

H. Response to Emission Rates

Summary of Issue: EPA does not agree with the approach within the analysis to apply correlation factors from the EPA protocol document because the data is based on Method 21 data and not on OGI. EPA makes the following statements about the correlations in the EPA Leak Protocol: *“The equations in Table 5-7 are based on specific leak definitions when using Method 21. These equations do not apply to monitoring using OGI... Even using the most conservative of the equations in Table 5-7 does not provide reasonable accuracy because OGI data is not expected to correlate point-by-point to Method 21 data. If it were possible to develop equations for OGI, they are unlikely to resemble the equations in Table 5-7. Additionally, as previously noted in Section 4.0 of this memorandum, we did not use these equations to determine the leak rate for OGI. Since we didn’t determine the leak fractions from the equations in Table 5-7, we do not believe it is appropriate to scale the emissions factors that we used with the leak fraction back calculated from the equations in Table 5-7.”*

API Response: EPA does not oppose the approach in our analysis, but rather, only opposes its application to OGI data. EPA’s rationale for dismissing our analysis on the basis that data within the EPA Leak Protocol are based on Method 21 data contradicts EPA’s own approach within the model plant

analysis that applies emission factors based on the same data. Specifically, EPA relied upon the general oil and gas leak emission factors from the 1995 Protocol for Equipment Leak Emission Estimates that are summarized in Table 2-4. As discussed above, these emission factors were developed from Method 21 data and applied to all components within the model plant as a representation of average leaks across all components within a population with an unknown initial leak incidence. The same application of the emission estimating methodology was applied for the model plant cost-benefit analysis for both Method 21 and OGI as EPA did not use separate emission factors to quantify baseline emissions based on leak detection techniques.

Further, it is noted that both the emission factors in Table 2-4 and the correlation equations from Chapter 5 of the EPA Leak Protocol are derived from Method 21 data – in fact, both the factors and collection of equations come from the very same Method 21 data. EPA did not rely upon the correlation equations in Chapter 5 directly. However, EPA did, in fact, rely upon Method 21 based emission factors to estimate the emissions from well sites that would be subject to OGI by relying on Table 2-4.

API did not object to the use of Table 2-4 in the original rulemaking as it was the best available data at the time. However, now that large amounts of data are available and are indicating that, for the average site, EPA has over-estimated the fraction of components leaking. It is both appropriate and necessary to reflect that in determining what frequency of leak survey is cost-effective and the net benefits that will actually be realized through implementation of Subpart OOOOa.

Recognizing that there are no correlation equations yet developed for OGI similar to what exists for Method 21, API reminds EPA of its determinations made during the Subpart OOOOa rulemaking when establishing Method 21 as an alternative to OGI, which was determined to be BSER:

“Available data show that OGI can detect fugitive emissions at a concentration of at least 10,000 ppm when restricting its use during certain environmental conditions such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal. Because an OGI instrument can only visualize emissions and not the corresponding concentration, any components with visible emissions, including those emissions that are less than 10,000 ppm, would be repaired.”

In other words, there is a high confidence that OGI will identify leaks over 10,000 and, in many cases, will also identify leaks at lower concentration levels. API therefore believes that applying EPA’s Method 21 correlation equations, based on a 10,000 ppm Method 21 leak threshold and a known leak incidence, is justified. In fact, it is a conservative approach since, in most conditions, OGI will identify leaks that are less than 10,000 ppm, thereby increasing the incidence rate for identification of leaks.

Further, we believe that, in absence of emission factor correlation data specific to OGI, the approach we used to derive more representative emission factors based on the known incidence rate is appropriate given EPA’s usage of similar Method 21 based data within the protocol and further detailed in the above comment on leak incidence rate.

API appreciates the opportunity to discuss approaches for updating EPA’s analysis in light of the data we have provided and additional data we expect to provide from Subpart OOOOa surveys.

Attachment B

API Analysis of Subpart OOOOa Semi-Annual Leak Survey Data

API Initial Analysis of Subpart OOOOa Fugitive Emissions Monitoring Data December 17, 2018

As a follow-up to our review of the data API provided to EPA in early 2018, API undertook a recent effort to collect Subpart OOOOa data from member companies to understand how data collected under the rule might differ from the broader dataset previously provided to EPA. The reported Subpart OOOOa data include data from both the initial and second reporting period and show trends that are entirely consistent with API's earlier dataset and analysis. Specifically, the Subpart OOOOa data show:

- There are large number of sites that have no leaks (58% of initial well site surveys).
- The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. Both values being well below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions.

These data confirm that EPA's initial assumption regarding the number of components leaking at well sites (and the corresponding mass of emissions) was significantly overestimated. API further believes that an evaluation of this data and any larger datasets from Subpart OOOOa data will confirm that a semi-annual survey frequency is not necessary or cost-effective for well sites.

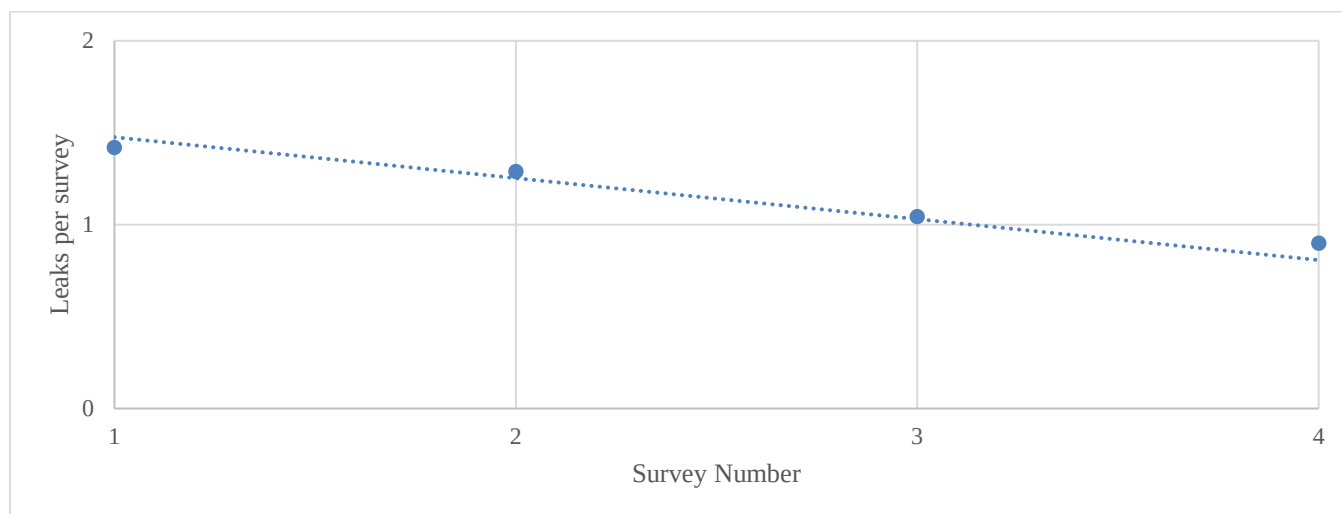
The remainder of this document provides an initial summary of the Subpart OOOOa dataset evaluated by API. API is continuing to analyze the data and welcomes the opportunity to discuss the data with EPA.

Summary of Leak Survey Dataset

- Two years of Subpart OOOOa Leak Survey Data for Sites Monitored at a Semi-Annual Frequency
- Over 6,000 total surveys across 3,482 sites
- Represents data from 13 different operators
- Surveys performed at sites located in: Kansas, Louisiana, North Dakota, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming
- For Initial Surveys at Sites Monitored at Semi-Annual Frequency – 58% of initial surveys found no (0) leaks
- Average number of leaks found per site = 1.42 for first survey and declines for subsequent surveys.

The following graphic illustrates the average count of leaks found per leak survey. As can be seen, the count of components found leaking averages around 1.4 components and steadily declines with each subsequent survey. While there is a decline over time as one would expect, the key observation from the data is that there are very few leaks being detected, on average, even during the initial leak survey.

Figure 1. Average Count of Leaks Found per Leak Survey Monitored per § 60.5397a



The table below summarizes the number of semi-annual survey data by company.

Company ID	Number of Leak Surveys
AA	904
BB	79
CC	156
DD	63
EE	1070
FF	497
GG	552
HH	39
II	730
JJ	121
KK	317
LL	727
MM	765

The table below summarizes the number of sites and leaks available from semi-annual survey data by survey number.

Survey Number	Total Number of Leak Surveys	Total Number of Leaks	Leaks per Survey
1	3,367	4,779	1.42
2	1,776	2,290	1.29
3	721	752	1.04
4	119	107	0.90

Summary of Findings

Figure 2 below illustrates the distribution of the number of leaks found during initial and subsequent semi-annual leak surveys. Observations from these data:

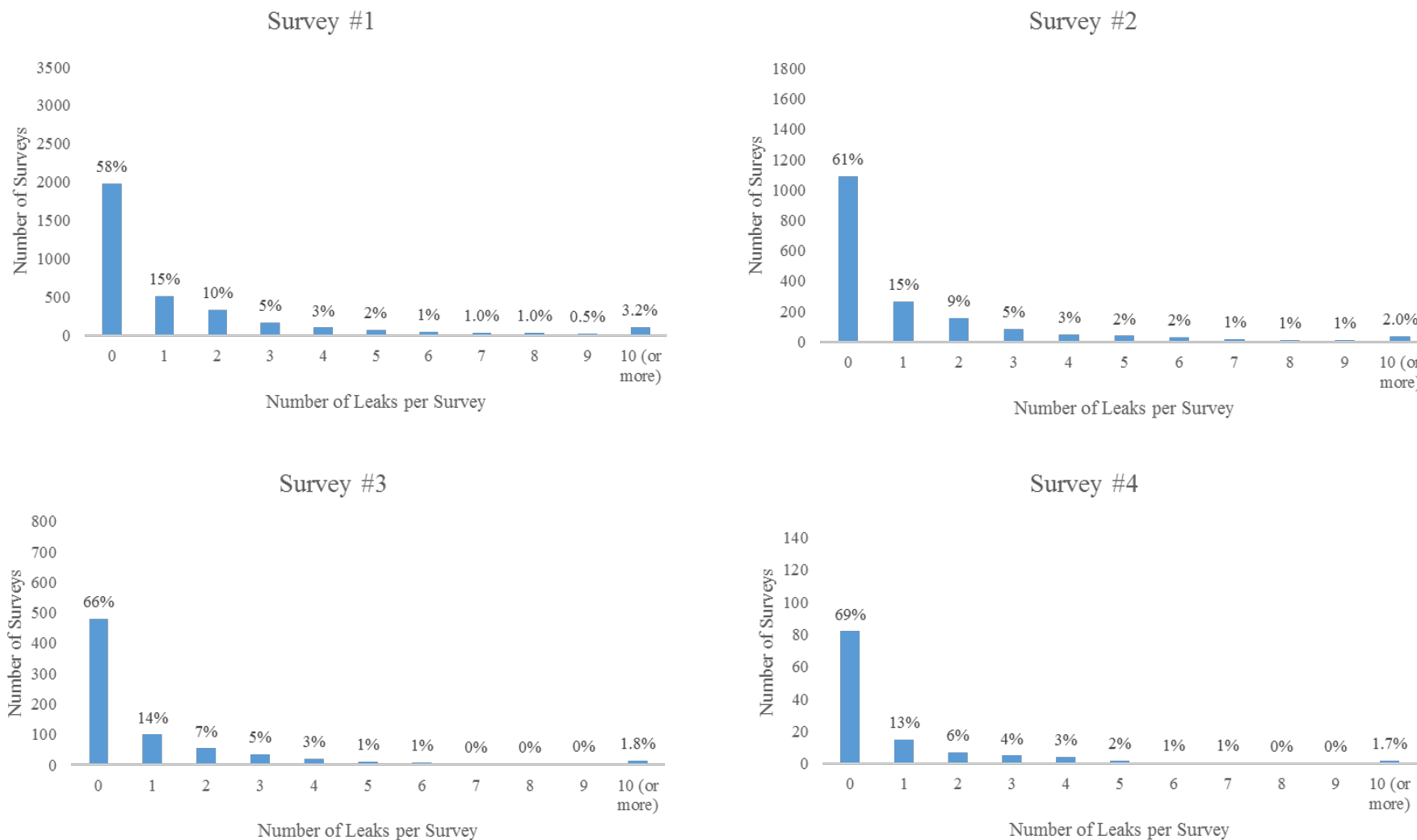
- A large percentage sites have no or very few leaks.
- With subsequent surveys, the percentages of sites with 0 or 1 leaks increases and the percentage of sites with 2 or more leaks decreases.
- Notably, while 3.2% of sites found 10 or more leaks in the initial survey, the percentage of sites with 10 or more leaks in subsequent surveys declines, going from 3.2% to 2.2% by the second survey and to 1.8% of sites by the third survey.

Conclusion

The Subpart OOOOa data described above confirm that the vast majority of well sites have very few leaking components – 92% of surveys identified 4 or less leaking components – with over half the surveys identifying no leaking components at all. In fact, approximately 60% of all surveys did not find any leaks. These data also are consistent with API’s previously submitted data and confirm that EPA overestimated the number of leaking components at the average well site used within the model plant.

While EPA previously expressed prior concern about certain aspects of the previous API survey data, API expects that providing these data developed from Subpart OOOOa surveys should adequately address any EPA concerns. The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA’s proposed annual survey frequency. While the dataset were not produced from a controlled experiment with a collection of well sites undergoing semi-annual monitoring and another set undergoing annual monitoring, the data clearly indicate that moving to an annual frequency will not result in an appreciable increase in emissions. API welcomes the opportunity to discuss these data further with EPA.

Figure 2. Semi-Annual Leak Survey Data Monitored per § 60.5397a Comparing Number of Leaks Found per Survey over Two Years



Attachment C

Production Flows and Operating Pressure

Discussion on Production Flows and Operating Pressures

EPA’s discussions in the preamble regarding increased production from refracturing a well (83 Fed Reg. at 52073), leads to the statement that “[T]he increase in production rate requires an increase to either the operating pressure and/or the duration of or frequency of flow events” is incorrect. The cited theory that to increase flow across a given cross-sectional area requires an increase in pressure is certainly true for a static system where the cross-sectional area is fixed. However, production flow through wellheads, process lines, separators and other equipment at a well site is a dynamic system in which pressure control valves adjust the cross-sectional area of their valve ports to moderate flow in order to maintain desired operating pressures. This allows a production unit to operate at the same approximate operating pressure over a wide range of flow rates.

Typically, the operating pressure of the first and/or second separator at a well site, or at a central tank battery with process equipment, is kept at a set pressure with a pressure control valve that allows more or less gas flow to the sales line. However, for production sites only, the most important control valves are “choke valves” on the wellhead.

The following is from EnggCyclopedia³⁵:

“Choke valve is a type of control valves, mostly used in oil and gas production wells to control the flow of well fluids being produced. Another purpose that the choke valves serve is to kill the pressure from reservoir and to regulate the downstream pressure in the flowlines. Choke valves allow fluid flow through a very small opening, designed to kill the reservoir pressure while regulating the well production. The reservoir fluids can contain sand particles. Hence the choke valves are usually designed to handle an erosive service.

Typically oil and gas producing wells have two choke valves in series, one non-regulating choke valve and one regulating choke valve downstream to the non-regulating choke valve.

Non-regulating choke valves

Function of the non-regulating choke valve is to act as an on-off valve and kill the reservoir pressure to a desired operating value in the flowline. The opening in the choke valve is sized to kill the pressure when valve is fully open. The non-regulating choke valve is not used for flow regulation and hence is not sized for controlling the flow. Over the life of an oil production well, the reservoir pressure drop as fluids are depleted from the reservoirs. Hence with dropping reservoir pressure, the non-regulating valves may have to be changed to maintain the same well production levels. Hence over the life of an oil production well, the non-regulating choke valves can be replaced with valves having increasingly larger openings for flow.

Regulating choke valves

The regulating choke valve is a flow control valve that is designed to maintain a steady production level in the flowlines and production header. Regulating choke valve is an automatic valve and valve opening can be controlled via electric or pneumatic signal from the control panel to regulate the flow in downstream flowlines.”

³⁵ <https://www.enggcyclopedia.com/2012/03/choke-valves/>

Therefore, in the case of a successful refracturing of a well which restores much of the well's reservoir pressure and results in an increased production rate, a regulating choke valve would adjust to maintain the desired operating pressure and, if needed, a non-regulating choke valve could manually be replaced with a valve having a smaller opening for flow."

Thus, the fugitive components downstream of wellhead valve would not necessarily experience an increase in pressure even though flow increased.

Attachment D

Sample Observation Narrative

The following is one example of a sample narrative to describe a general process a company could use to describe an observation path as discussed in detail in Comment 3.0.

Observation Path at Well Site: The path shall start at the wellhead or inlet header and move along any lines attached containing the possibility of leaking fugitive emissions. This path should encompass any storage and process vessels on the site. The physical path followed by the inspector will differ from site to site due to the construction layout of each well site. The inspector will need to adjust distance from components based on camera lens, wind speed, and any adverse monitoring conditions to identify any fugitive emissions from all applicable components.

Observation Path at Compressor Station: The path shall start at the inlet header and move along any piping containing the possibility of leaking fugitive emissions. This path should encompass any storage and process vessels on the site. The physical path followed by the inspector will differ from site to site due to the construction layout of each compressor station. The inspector will need to adjust distance from components based on camera lens, wind speed, and any adverse monitoring conditions to identify any fugitive emissions from all applicable components.

Deviation from Observation Path: Any deviations from this monitoring path will need to be recorded on the survey sheet. In the event that no deviations from the monitoring path occur, inspector will note there were no deviations from the monitoring path.



December 4, 2015

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2010-0505

Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, CO2 emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (Control Techniques Guidelines, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,



Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

Attachment

**API Comments on the Proposed Rulemaking –
Standards of Performance for New Stationary
Sources: Oil and Natural Gas Production and
Natural Gas Transmission and Distribution**

December 4, 2015

Docket ID No. EPA-HQ-OAR-2010-0505

EXECUTIVE SUMMARY

As detailed in our comments, API has numerous concerns with EPA's proposed New Source Performance Standard (NSPS) rulemaking for the oil and natural gas sector (40 CFR Part 60, Subpart OOOOa). EPA has indicated the desire to finalize the proposed rule in June of 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments and develop a final rule that protects the environment and does not hinder America's energy renaissance. This is an unrealistic schedule for issuing a complex rule with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final rule to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of the proposed rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has justified the proposed regulation using economic studies on "average model facilities" without determining whether the resulting proposed control requirements are appropriate for the entire range of sources included in the source category. The proposed rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, while relying on unsound legal justification. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

Direct Regulation of Methane is Unlawful

Issue – Section 111 of the Clean Air Act (CAA) requires the Agency to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA §111(b)(1)(A). It is unlawful for EPA to regulate only methane from oil and natural gas sources based on an endangerment finding that is largely attributable to other GHG pollutants from non-stationary sources. In the 2009 endangerment finding for motor vehicles, EPA found that "carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change." See, e.g., 74 Fed. Reg. at 66519. Given that EPA concluded that carbon dioxide from motor vehicles—not methane—is the "driver of climate change," EPA cannot rely on that past finding in a rule that regulates only methane. EPA has not shown that there is a rational basis for concluding that methane, a single element of the aggregate pollutant GHGs, meets the endangerment standard called for in the CAA, or that upstream oil and natural gas sources are a significant contributor of methane. Both showings are legal prerequisites before EPA may propose Subpart OOOOa.

Recommendation – EPA must make both an endangerment and significant contribution finding for each pollutant that it seeks to regulate for a given source category. In this case, an endangerment finding must be made for methane specifically, and a significant contribution finding must be made for the proposed covered sources.

Refer to Comments 3.0 and 4.0 for detailed comments on this matter.

Direct Regulation of Methane is Unnecessary

Issue – In the proposed rule, EPA states that, for some of the regulated affected facilities, direct regulation of methane accomplishes no further reduction in methane emissions than would occur through regulation of VOC alone. EPA recognizes that under its proposal, the same controls would be required for VOC and methane as are currently required for VOC under Subpart OOOO. EPA's decision to directly regulate methane from those same sources covered by OOOO, despite this admission - which means that no significant additional methane emissions reductions will occur - is arbitrary and capricious. There is no rational basis for taking the wholly discretionary action of regulating methane or GHGs from this part of the oil and natural gas sector where EPA would achieve no additional methane reductions beyond those achieved through existing VOC standards. None of EPA's asserted reasons have merit, and therefore, EPA has not made a showing that revision of the standards is "appropriate," as required under section 111(b)(1)(B).

Recommendation – EPA should continue the practice of indirectly regulating methane through the use of natural gas as a surrogate for VOC.

Refer to Comment 7.0 for detailed comments on this matter.

EPA Needs to Address Permitting Implications Associated with Regulation of Methane

Issue – EPA has not addressed the possible permitting implications that would flow from the direct regulation of methane. Unintended implications could include allowing methane alone to trigger PSD and Title V permitting for all sources, not just oil and natural gas sources, which would greatly increase permitting burdens and result in costs that EPA did not consider in the rulemaking. API has raised PSD permitting issues previously with the EPA and understands that EPA does not intend for NSPS OOOOa to trigger PSD and Title V permitting applicability as that runs counter to both Congressional intent and judicial precedent. Agencies and states cannot handle an increased permitting burden, and such a trigger would drastically increase the number of permits submitted, not only for the oil and natural gas sector, but for all sectors.

Recommendation – As a threshold matter, API presents the following solution to the PSD and Title V permitting issues without conceding its position that EPA is required to make a separate endangerment finding for methane and a significant contribution finding for methane from this source category. To address the possible PSD and Title V permitting implications, EPA should adopt an approach similar to that taken in the Clean Power Plan (NSPS Subpart TTTT). Specifically, EPA should make it clear that the pollutant being regulated under NSPS OOOOa is the group of six GHGs. EPA should also make it explicitly clear that methane is being used as a surrogate for the group of six. Additionally, EPA should include an explanation as well as a provision in the final rule that extends the Tailoring Rule to cover regulation of GHGs under NSPS OOOOa.

Refer to Comment 6.0 for detailed comments on this matter.

Equipment Leak Requirements

Issue – EPA has proposed a process that requires significant, unnecessary recordkeeping and reporting and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation –Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Comment 27.0 for detailed comments on this matter.

Pneumatic Pump Applicability and Technical Feasibility

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit. EPA has ignored critical technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential safety and operational issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should exempt low emitting pumps and low usage pumps, i.e. pumps that emit at an equivalent rate lower than a high bleed controller. This would be consistent with the position taken in Subpart OOOO and reinforced under the Subpart OOOOa proposal for pneumatic controllers. EPA should also provide an exemption from the requirements to control pump emissions where it has been determined to be technically infeasible or potentially unsafe.

Refer to Comment 24.0 for detailed comments on this matter.

Oil Well Completions

Issue – EPA needs to accommodate additional exemptions for certain oil well completions. There are a wide range of conditions experienced across different oil and natural gas fields and additional provisions are needed in the rule to clearly exempt certain scenarios.

Recommendation – In addition to the exemption for wells producing less than 300 scf of gas per bbl of oil, EPA should include exemptions for wells requiring artificial lift to complete flowback and for periods when flowback has stable entrained gas, foam, emulsion, or infrequent slugging gas flow such that a separator cannot be operated.

Refer to Comment 22.2 for detailed comments on this matter.

EPA Must Recognize Implementation Challenges

Issue – As we learned in the development of Subpart OOOO, API urges EPA to exercise caution in the development of these rules to allow operational flexibility as it seeks “one size fits all” regulatory solutions. Consideration must be given to the implementation of these new rules to ensure industry is able to comply. Consistent with the original Subpart OOOO rulemaking, EPA should consider a similar compliance schedule for the proposed NSPS rule. We would also urge EPA to accommodate operators that are currently implementing leak monitoring and repair requirements, whether due to existing air permits, state or local regulations or voluntary commitments, to satisfy the federal rule requirements and minimize regulatory burden for those operators.

Recommendation – If promulgated as written, EPA should allow a phased implementation for completion, pneumatic pump, and leak detection and repair (LDAR) requirements to accommodate the number of affected facilities and the associated engineering, implementation and training needed to comply with the new rules.

Refer to Comments 22.5, 24.0 and 25.0 for detailed comments on this matter.

Compliance Assurance Requirements for Subpart OOOOa Are Overly Burdensome

Issue – The monitoring and testing requirements are overly burdensome for Subpart OOOOa. The remote, dispersed and unmanned nature of facilities that lack electrical power, make the requirements logistically impractical, technically difficult and uneconomic. The use of NESHAP HH major source-type compliance requirements for storage vessels is confusing and unjustifiably stringent for NSPS.

Recommendation – CPMS requirements for monitoring centrifugal compressors and pneumatic controllers should be eliminated in lieu of the sensory inspections required for storage vessels. Additionally, the performance testing requirements should be revised.

Refer to Comment 12.2 and 12.4 for detailed comments on this matter.

Subpart OOOO Retroactive Requirements

Issue- EPA proposed several new requirements for control devices and closed vent systems to subpart OOOO that could be viewed as new requirements to be applied retroactively to affected facilities initially constructed between August 23, 2011 and September 18, 2015. This is inappropriate as NSPS rule changes may only be prospective and not retrospective. Amongst the numerous changes, proposed paragraph §60.5370(d) encapsulates the problem best by stating: *You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.* This suggests that new requirements in subpart OOOOa for subpart OOOO affected facilities will be applicable when subpart OOOOa is finalized. The only purpose for modifying subpart OOOO should be to end date the rule since it is being replaced with subpart OOOOa.

Recommendation – EPA should remove all new compliance requirements being proposed in subpart OOOO and only finalize changes to paragraphs §60.5360 and §60.5365 which end date the applicability of subpart OOOO and that correct issues that do not add new regulatory burden.

Refer to Comment 19.0 for detailed comments on this matter.

Multipollutant Cost Effectiveness Approach is Not Appropriate

Issue – In justifying the proposed requirements, EPA utilized a multipollutant approach to determine if costs were reasonable. EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." See 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. See *id.* at 56636.

Recommendation – EPA must re-evaluate and only assess the reasonableness of costs based on each pollutant.

Refer to Comment 10.0 for detailed comments on this matter.

Social Cost of Methane

Issue – EPA has inappropriately applied a social cost of methane (SC-CH₄) estimate that is highly speculative, not sufficiently peer-reviewed, and ultimately not suitable for policy applications. The SC-CH₄ is based on the approach used for quantifying the social cost of carbon (SCC) and therefore carries with it all of the same challenges to accurately calculating the benefits of the rule, and seriously affect the scientific and economic reliability of the SC-CH₄. The peer-reviewers selected by EPA did not reach a consensus and all found inconsistencies and other issues with the calculations used to generate the SC-CH₄, as did an independent review by NERA. The issues associated with the estimation and use of the SC-CH₄ include: differences in the way methane emissions was included in the three models; significant differences in the damage functions between the models; issues with the averaging approach used to synthesize the results; the inclusion of an unjustifiably low discount rate given the short atmospheric lifespan of CH₄; the inclusion of global benefits rather than domestic benefits; and the *ad hoc* nature of EPA's assumption of the indirect effects on radiative forcing. Independent review by NERA found that the benefits provided by the rule, after compensating for flaws in EPA's calculation, could be as much as 94% lower. When combined with the revised cost estimates and reduced emission benefits found by ERM, the rule could result in net costs of more than \$1 billion in 2025.

Recommendation – There are significant uncertainties inherent in the newly-developed social cost of methane (SCM) calculation, and it may significantly overestimate methane's environmental impacts. Further, there has been a lack of adequate peer review for the SC-CH₄ estimate. As such, EPA's use of the social cost of methane is inappropriate to justify this rulemaking.

Refer to Comment 21.0 for detailed comments on this matter.

Next Generation Compliance

Issue – API believes the Next Generation Compliance Options discussed in the proposal preamble are unnecessary and represent an overreach by EPA of its authority. API believes the Next Generation Compliance Alternatives discussed in the preamble are not feasible or legal, nor do they achieve goals of assuring better compliance.

Recommendation – EPA must justify the legal basis for and formally propose any Next Generation Compliance provisions in a separate rulemaking before adopting them.

Refer to Comment 18.0 for detailed comments on this matter.

Electronic Reporting

Issue – EPA should not write electronic reporting into Subpart OOOO and Subpart OOOOa until the system is able to accommodate the unique nature of the oil and natural gas industry. The electronic reporting system is not proven generally at this time. Further, the system will require configuration to allow the current area based reporting vs facility by facility. In the past, system revisions have resulted in significant IT challenges, and appropriate time needs to be allowed for the agency to develop, QA/QC, user test and train reporters on the new system.

Recommendation – EPA should amend the final rule language to formally allow for continuation of current reporting approaches (under Subpart OOOO) for three years to allow for rollout of the electronic reporting system..

Refer to Comment 11.0 for detailed comments on this matter.

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Attachments

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Attachment B – API Comments on EPA's NSPS Electronic Reporting Proposal
Attachment C – Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas
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GENERAL COMMENTS

Throughout these comments API has provided suggested rule language to assist in revised regulatory text in redline/strikeout format. A consolidated version is provided of recommended rule language in Attachment A by section. While Attachment A has been prepared as a summary of API's suggested edits to the rule language, the markups shown in these comments should be taken as our preferred position in the event of any differences between these comments and Attachment A.

1.0 EXTENSION OF COMMENT PERIOD AND FINAL RULE DEADLINE

While API appreciates the additional 17 day extension that EPA granted to submit comments, a minimum of 120 days was required to provide an adequate set of comments to a rulemaking as broad, high impact, precedent setting, and complex as these proposed rules. Further, the NSPS rules are only a part of the proposed regulations that our industry is facing. EPA has also released proposed control technique guidelines for implementation of the revised ozone air quality standard and pending regulatory requirements from the Department of Interior's BLM on federal lands will also add to the cumulative impact to our industry and future operations. We urged the EPA and the Administration to coordinate its efforts and strongly encouraged EPA to extend its comment periods to allow a minimum of 30 days overlap with the BLM rulemaking currently under development.

Without this overlap, industry does not have the chance to understand the cumulative impacts and provide meaningful feedback to avoid conflicting requirements across the separate agencies. API has developed as complete a set of comments as time allowed. However, much of the information EPA requested, as well as additional information API wanted to provide is not included because of time limitations.

2.0 EPA UNLAWFULLY SEEKS TO EXPAND THE OIL AND NATURAL GAS SECTOR SOURCE CATEGORY

In the proposed rule, EPA seeks to unlawfully expand the scope of the oil and natural gas sector source category—even beyond the expansion that EPA undertook in 2012 with Subpart OOOO, which API has opposed as unlawful.¹ EPA's attempt here to expand even further the types of emissions sources that would be subject to the NSPS is likewise unlawful. In this proposal, several types of never-before-regulated emissions sources would be regulated under NSPS: hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites, and compressor stations. 80 Fed. Reg. at 56594. Some source types would also be regulated more generally for methane and VOC emissions, as only a small subset are currently regulated for VOC: pneumatic controllers, centrifugal compressors, and reciprocating compressors (except for compressors at well sites). *Id.* at 56595.

2.1 The Scope Of The Source Category Is Unlawfully Overbroad And Not Supported By The 1979 Listing Or The Gas Processing Plant NSPS

EPA's proposed NSPS would cover an even greater number of very small source types in EPA's broadly defined "oil and natural gas source category," which, according to EPA, includes production, processing,

¹ API Comments on 2011 Proposed NSPS at 3-8 (Nov. 30, 2011), EPA-HQ-OAR-2010-0505-4266 ("API 2011 Comments").

transmission, and storage. *Id.* at 56594. EPA again maintains, as it did in the original Subpart OOOO rulemaking, that all emissions sources proposed for regulation are covered by its 1979 listing of the oil and natural gas category. See *id.* at 56600 (“EPA interprets the 1979 listing broadly to include the various segments of the natural gas industry (production, processing, transmission, and storage).”).

EPA is incorrect that the 1979 original source category determination can be read to include the numerous smaller emissions points covered by this proposal. The 1979 listing was focused on major-emitting operations and cannot be reasonably construed as encompassing small, discrete sources that exist separate and apart from a large facility, like a processing plant.

In its 1979 listing, EPA made it clear that the category was listed to satisfy section 111(f) of the Clean Air Act. 44 Fed. Reg. 49222 (Aug. 21, 1979). That section required EPA to create a list of “categories of major stationary sources” that had not been listed as of August 7, 1977, under section 111(b)(1)(A) of the Act and to promulgate NSPS for the listed categories according to a set schedule. EPA explained in the listing rule that its list included “major source categories,” which EPA defined to include “those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant.” *Id.*

Although EPA provided no further explanation in its original 1979 listing decision as to what facilities it intended to regulate under the “crude oil and natural gas production” source category, there can be no doubt that the category originally included “stationary sources” (i.e., “plants”) that typically have a potential to emit at least 100 tons per year of a regulated pollutant. This communicates two important limitations on the original listing decision. First, EPA was focused on discrete “plants” or “stationary sources.” Second, EPA was focused on large emitting plants or stationary sources. As a result, the original listing decision cannot reasonably be interpreted to extend to the types of sources EPA seeks to regulate in the proposal. The additional source types that EPA seeks to regulate in this proposal could not plausibly be considered part and parcel of major emitting plants.

EPA claims that its priority list analysis at the time of original listing shows that the Agency intended to regulate sources beyond the “production source segment” category because EPA evaluated equipment that is used in various segments of the natural gas industry, such as stationary pipeline compressor engines. 80 Fed. Reg. at 56600. But this does not evince an intent to regulate non-major source types but only that the Agency evaluated equipment located at what it perceived to be major facilities.

EPA next asserts that in the preamble to a subsequently proposed NSPS for natural gas processing plants, “EPA described the major emission points of this source category to include process, storage and equipment leaks,” and that this supports broad regulation of even the smallest sources in the oil and natural gas industry. See *id.* (citing 49 Fed. Reg. 2636, 2637 (Jan. 20, 1984)). But, EPA recognized that the emissions points it was proposing to regulate in that rulemaking—process units and compressors—were located at gas processing plants. 49 Fed. Reg. at 2638; see also 50 Fed. Reg. 26122, 26123 (June 24, 1985) (affected units in final rule are process units and compressors at gas processing plants). It is telling that the Agency decided to regulate only natural gas processing plants—the closest thing to a major-emitting plant that can be found in this sector—in that NSPS.

2.2 EPA Is Not Authorized To Arbitrarily Expand A Source Category

As explained above, EPA incorrectly asserts that it is not listing a new source category or otherwise expanding the existing category. See 80 Fed. Reg. at 56600-01. The Agency goes on to say that even if a revision of the source category were required, it believes it is presenting information sufficient to support that revision by showing that four “segments” of the oil and natural gas industry warrant regulation. *Id.* at 56601, 56608-09. EPA is incorrect.

EPA fails to make the required statutory findings. Under section 111(b)(1)(A), EPA is authorized to regulate additional source types if and only if it: (1) defines a discrete “category” of stationary sources;

and (2) determines that emissions from the source category cause or significantly contribute to endangerment to health or the environment.

EPA makes no effort whatsoever to demonstrate that emissions from the particular additionally-regulated sources in Subpart OOOOa cause or contribute to endangerment to health or the environment. Instead, the Agency simply asserts general public health effects associated with GHGs, VOC, and SO₂ and then evaluates emissions from oil and natural gas sources generally. See *id.* at 56601-08. For methane, EPA merely breaks down emissions into four general “segments” (natural gas production, natural gas processing, natural gas transmission and storage, and petroleum production) but does not evaluate particular source type emissions within those segments. EPA does nothing to break down its evaluation of emissions even by sector segment for SO₂ and VOC. This failure to investigate the key statutory listing criteria is patently arbitrary and plainly violates the requirement in section 307(d)(3) of the Clean Air Act to clearly set forth the basis and purpose of the proposal.

Under EPA’s logic, as long as certain types of stationary sources in a category, or segment of a category, cause or significantly contribute to endangerment to health or the environment, it can lump together in the defined source category (or segment of a source category) all manner of ancillary equipment and operations, even if those ancillary equipment and operations do not in and of themselves significantly contribute to the previously-identified endangerment. See *id.* at 56601. This is not a reasonable interpretation of section 111(b)(1)(A) because such an interpretation would bestow virtually unlimited regulatory authority upon EPA—allowing EPA to evade the express listing criteria by creating loose associations of nominally related sources in a sector.

Lastly, section 111(f)(3) of the Clean Air Act requires EPA to “consult with appropriate representatives of the Governors” prior to “promulgating any regulations under this subsection.” As explained above, EPA originally listed the “crude oil and natural gas production” source category in 1979 pursuant to section 111(f), which means that the requirement of section 111(f)(3) applies. Consequently, EPA has a clear obligation to consult with the Governors and should have done so prior to proposing the rule so that the public would have an opportunity to know the views of the Governors and submit comments on the record. Although EPA did have some general discussions with the States, see *id.* at 56609, this does not meet the procedural requirement of section 111(f)(3). EPA’s failure to consult with the Governors and State air pollution control agencies on the specific substance of this proposal—including whether the category can be revised in the way contemplated and whether the standards are appropriate – is a fundamental procedural error. The uniqueness of the new affected facilities (very small in cost and/or quantity of emissions or of non-routine, temporary, and construction nature) in particular justifies consultation with the States on the specific proposed action as it will further increase the States’ permitting burdens if finalized.

2.3 EPA’s Regulation Of Extremely Small Affected Facilities Is Unlawful

As it did in the 2012 rule finalizing Subpart OOOO, EPA errs in this proposal in asserting that single individual components (such as pneumatic devices, compressors, and tanks) and single activities (such as each oil well completion) constitute separate “affected facilities” for purposes of the NSPS. See *e.g.*, Proposed § 60.5365a, 80 Fed. Reg. at 56663. EPA’s fine parsing of the definition of affected facility to expand applicability of the rules is fundamentally flawed for three distinct reasons.

First, EPA fails to explain where it finds legal authority for such an approach, and thus, falls far short of EPA’s obligation to include in the proposed rule “the major legal interpretations... underlying the proposed rule.” CAA § 307(d)(3)(C).

Second, and more importantly, the proposal is flawed because the statute simply does not confer authority on EPA to define a source category and then define a different “affected facility” for purposes of determining what constitutes a new source. As explained above, the statute unambiguously requires EPA

to identify and regulate “categories of stationary sources.” *Id.* § 111(b)(1)(A). Similarly, the statute defines the term “new source” to mean “any stationary source” that is constructed or modified after proposal of an applicable standard. *Id.* § 111(a)(2). There can be no doubt that the “stationary source” that is identified for listing purposes must be the same “stationary source” used to define what constitutes a new source. In other words, by defining a category of “stationary sources” to be regulated under section 111, EPA unavoidably identifies the “stationary source” that must be used in applying the definition of “new source.” *See* 80 Fed. Reg. at 56610 (“We note that the terms ‘emission source,’ ‘source type’ and ‘source,’ as used in this preamble, refer to equipment, processes and activities that emit VOC and/or methane. This term does not refer to specific facilities, in contrast to usage of the term ‘source’ in the contexts of permitting and section 112 actions.”).

To be sure, section 111 provides EPA with some regulatory flexibility—for example, the Agency clearly “may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.” CAA § 111(b)(2). But the authority to parse a given category of stationary sources for purposes of standard setting is distinctly different from the asserted authority to redefine what constitutes a “new source” within the given source category. *Asarco Inc. v. EPA*, 578 F.2d 319, 327 n.24 (D.C. Cir. 1978) (“This language on its face merely allows the Administrator to set different standards for different classes, types, and sizes of sources. It does not give the Administrator authority to rewrite the definition of a stationary source....”). EPA has flexibility in defining in the first instance the stationary sources to be regulated, but the act of defining the “stationary sources” fixes the “affected facility” for purposes of determining what constitutes a new source.

Third, even assuming for the sake of argument that EPA has authority to designate portions of stationary sources as “affected facilities” for purposes of determining what constitutes a “new source,” EPA has failed to follow the analytical framework established in prior rules for making such designations. For example, in establishing the NSPS for VOC emissions from synthetic organic chemical manufacturing industry (“SOCMI”) wastewater, EPA explained that a balancing must be done. A “narrower” definition of affected facility can be favorable because “a broader definition means that replacement equipment is less likely to be regulated under the NSPS.” 59 Fed. Reg. 46780, 46789 (Sept. 12, 1994). On the other hand, a “broader” definition may be appropriate upon consideration of “the relevant statutory factors (technical feasibility, cost, energy, and other environmental factors).” *Id.* In the case of the SOCMI rule, EPA selected the process unit as the appropriate affected facility because it “allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards.” *Id.* at 46790. EPA’s failure to engage in reasoned assessment according to these established criteria renders the proposed rule arbitrary and capricious and not in accord with the law.

2.4 Hydraulically Fractured Oil Well Completions Cannot Be “Affected Facilities” Under NSPS

In this rulemaking, EPA proposes to regulate hydraulically fractured oil well completions for the first time. API has opposed EPA’s prior proposal to regulate natural gas well completions. *See* API 2011 Comments at 7-8. EPA rejected those comments in a cursory manner in the 2012 Subpart OOOO final rule. 77 Fed. Reg. at 49511 n.11. EPA disagreed with API’s assertion that EPA’s regulation of well completion is a regulation of “construction activities,” and instead maintained that the Agency was regulating “emissions resulting from the physical change.” *Id.*

API reiterates its comments made with regard to natural gas well completions because they are equally applicable to EPA’s proposal to regulate oil well completion for the first time. Emissions from well completions differ fundamentally from emissions regulated under any NSPS prior to Subpart OOOO. It goes without saying that the purpose of oil wells is to produce oil. A well completion is not part of the normal operation of a well in that completion activities do not continuously occur as a well is producing

or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be “recompleted,” this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

Until EPA's unlawful regulation of natural gas wells in 2012, EPA had never sought to impose section 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA had actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until “within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.” 40 C.F.R. § 60.8(a). Similarly, performance tests must be conducted under conditions reflecting “representative performance of the affected facility.” *Id.* § 60.8(c). Prior to Subpart OOOO, periods of source construction and maintenance had never been suggested to be “representative” of normal source operation under the NSPS program.

To the extent that well completions can be considered a “stationary source,” which API disputes, they are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and natural gas production industry (such as natural gas processing plants). EPA has not previously found and has not proposed to find that emissions from well completions cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate well completions under section 111.

In addition, EPA has not explained why it has not followed a decades-long practice under section 111 of regulating emissions that result only from normal operation of affected facilities and expressly excluding construction-related emissions from regulation in this proposal. As noted in API's 2011 comments, regulation of construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of section 111. The failure to provide a reasoned explanation of why this departure is justified, and the failure to present the legal basis for regulating non-routine emissions, is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth “the major legal interpretations and policy considerations underlying the proposed rule.” CAA § 307(d)(3)(C).

3.0 EPA CANNOT RELY ON AN ENDANGERMENT FINDING FOR A COLLECTION OF SIX GREENHOUSE GASES TO REGULATE ONLY METHANE

Section 111 requires the Agency to list a category of stationary sources if, in the Administrator's judgment, the category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” *Id.* § 111(b)(1)(A). This requires the Agency, first, to make an “endangerment finding” that the air pollution it intends to regulate from that source category “may reasonably be anticipated to endanger public health or welfare.” *Id.* Next, the agency must determine that the source category “causes, or contributes significantly to” that air pollution. *Id.* These threshold findings are required before EPA proposes new standards for existing source categories.

In December 2009, EPA made an endangerment finding for motor vehicles under section 202(a) of the Clean Air Act in which the Agency determined that “six greenhouse gases *taken in combination* endanger both the public health and the public welfare . . .” 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009) (emphasis added). EPA “[s]pecifically . . . define[d] the ‘air pollution’ referred to in CAA section 202(a) to be the *mix of six long-lived and directly-emitted greenhouse gases* . . .,” *id.* at 66497 (emphasis added), in the “aggregate,” *id.* at 66519. EPA made clear that “the air pollution is the *combined mix* of six key directly-emitted, long-lived and well-mixed greenhouse gases . . .” *Id.* at 66516 (emphasis added). The six greenhouse gases included in the aggregate in EPA's section 202(a) endangerment finding were carbon

dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). *Id.*

In the proposal here, EPA “identifies the air pollutant that it proposes to regulate as the pollutant GHGs . . .” *Id.* at 56601. EPA explains that of the “six well-mixed GHGs . . . only two of these gases—CO₂ and methane—are reported as non-zero emissions for the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule.” *Id.* at 56607-08. As EPA admits, however, “only methane will be reduced directly by the proposed standards.” *Id.*

It is unlawful for EPA to regulate only methane based on an endangerment finding that is largely attributable to other pollutants. Of the six greenhouse gases, carbon dioxide is emitted in vastly greater quantities (even on a carbon dioxide equivalent basis) than methane. In the 2009 endangerment finding for motor vehicles, EPA recognized this, finding that “carbon dioxide is expected to remain the *dominant anthropogenic greenhouse gas, and thus driver of climate change.*” *See, e.g.,* 74 Fed. Reg. at 66519. Given that EPA concluded that carbon dioxide—not methane—is the “driver of climate change,” EPA cannot rely on that past finding in a rule that regulates only methane. EPA has not shown that there is a rational basis for concluding that methane, a single element of the aggregate pollutant GHGs, meets the endangerment standard called for in the statute.

4.0 EPA MUST MAKE AN ENDANGERMENT AND SIGNIFICANT CONTRIBUTION FINDING FOR EACH POLLUTANT THAT IT SEEKS TO REGULATE FOR A GIVEN SOURCE CATEGORY

EPA sets forth a so-called “rational basis” approach to the regulation of pollutants under section 111 under which it asserts that an endangerment and significant contribution finding based on *one* pollutant emitted by a source category broadly gives EPA the ability to regulate *any* pollutant emitted from that source category. EPA claims that:

[O]nce the EPA has determined that the source category causes, or contributes significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare, and has listed the source category on that basis, the EPA interprets section 111(b)(1)(A) to provide authority to establish a standard of performance for *any* pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.

80 Fed. Reg. at 56601 (emphasis added). EPA bases its position on three claims. First, EPA argues that the Agency is not required to make a new endangerment finding with regard to the source category because it is not listing a new source category. *Id.* In EPA’s view, section 111(b)(1)(A) requires an endangerment finding only in order to initially list a source category. *Id.* Second, EPA argues that EPA has discretion, in what it determines to be a statutory gap, to specify what pollutants should be regulated once a source category is listed. *Id.* Third, EPA claims that past Agency practice supports this approach. *See id.* (“EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated.”). As such, EPA “believes that the 1979 listing of this source category provides sufficient authority for this action . . .” *Id.*

EPA’s interpretation directly contradicts the plain language of section 111(b)(1)(A) of the Clean Air Act. That section requires EPA to list a category of stationary sources if, in the Administrator’s judgment, the category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” CAA § 111(b)(1)(A). This section unambiguously requires EPA to list and regulate according to endangerment and significant contribution findings for particular pollutants. EPA mistakes its source of authority for an unlimited grant of authority. Read in context, the statute permits EPA to regulate stationary sources that emit pollutants that may reasonably be anticipated to endanger public health or welfare *for those pollutants* which led to the endangerment finding and to which the source category significantly contributes. It does not grant EPA unlimited authority to regulate

any pollutant emitted by that source. See *Mich. v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (“EPA is a federal agency—a creature of statute. It has . . . only those authorities conferred upon it by Congress [I]f there is no statute conferring authority, a federal agency has none.”).

Even if the statute were ambiguous, EPA’s interpretation of the statute is unreasonable. EPA claims that the statute is silent as to what pollutants should be the subject of standards from the source category, and “in the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of [a] standard, it is appropriate for EPA to exercise its authority to adopt a reasonable interpretation of this provision.” 80 Fed. Reg. at 56593, 56601. Into this alleged statutory silence, EPA injects the “authority to establish a standard for performance for *any* pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.” See *id.* (emphasis added). Regulating any pollutant emitted from a source category based on an endangerment and significant contribution finding for just a single pollutant is manifestly unreasonable. EPA may not simply substitute a “rational basis test,” which is not contained in Section 111 of the Clean Air Act, for its more stringent requirements.

Under the Agency’s interpretation, EPA’s regulation of *any* pollutant is limited only by EPA’s prior determination that *an entirely different pollutant* endangers public health or welfare, that the source category’s emissions of that different pollutant contribute significantly to that endangerment, and that there is somehow a “rational basis”—words not found in section 111—to regulate other pollutants. This is not a test. It is an unlimited grant of authority for EPA to be the final arbiter of whether to regulate pollutants for which it has not made the necessary statutory findings.

After a single endangerment and contribution finding, EPA could for all intents and purposes regulate any pollutant from that source regardless of whether the source contributed significantly to the endangerment in question. This is not what Congress intended when it established such a high bar for regulation under section 111(b). See CAA § 111(b)(1)(A). EPA’s interpretation is untethered from the statute, adrift in an unlimited “rational basis test” of the Agency’s own creation. This is a patently unreasonable interpretation of the statute.

EPA’s position is even more untenable because it relies on a cause-or-contribute significantly finding made for a different pollutant over thirty years ago. A significant period of time has passed since EPA made its finding. EPA’s original finding for this source category may no longer be valid. Regulating methane on the basis of a finding made many years earlier that the source category contributed significantly to endangering pollution of another kind without an independent examination and analysis of the pollutant that EPA intends to regulate is arbitrary and capricious.

5.0 THE PROPOSED SIGNIFICANT CONTRIBUTION FINDING FOR METHANE EMISSIONS FROM THE OIL AND NATURAL GAS SECTOR IS UNLAWFUL BECAUSE EPA FAILED TO DEFINE WHAT CONSTITUTES “SIGNIFICANT” CONTRIBUTION

As an alternative to its “rational basis” test, EPA proposes to find that methane emissions from the oil and natural gas sector contribute significantly to endangering GHG emissions. 80 Fed. Reg. 56593, 56601. This alternative finding is unlawful because EPA provides no legal basis or analysis as to what constitutes a “significant contribution.” In fact, EPA’s recent actions suggest that EPA has no standard for making a “significant contribution” finding. When EPA proposed standards of performance for GHG emissions from new electric generating units (“EGUs”), the Agency stated in the preamble that:

[I]f the EPA were required to make a cause-or-contribute-significantly finding for CO₂ emissions from the fossil fuel-fired EGUs, as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. In particular, as

noted, *fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions*, and constitute by far the largest single stationary source category of GHG emissions; and the CO₂ emissions from even a single new coal-fired power plant may amount to millions of tons each year.

79 Fed. Reg. 1430, 1456 (Jan. 8, 2014). EPA noted that “at present, it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution” because “[u]nder any reasonable threshold or definition, the emissions from EGUs are a significant contribution.” *Id.* Thus, in the proposed NSPS for EGUs, EPA recognized that a specific reasonable threshold for “significant contribution” may be necessary, but the agency determined that one-third of all U.S. GHG emissions would be significant “[u]nder any reasonable threshold.” *Id.*

Regardless of EPA’s position in the proposed NSPS for EGUs, it is plainly unreasonable for EPA to make the same assumption here. In the proposed rule, EPA concludes that GHG emissions from oil and natural gas processing and transmission sources constitute 3 percent of total GHG emissions in the United States and 0.3 percent of global GHG emissions. 80 Fed. Reg. 56593, 56608. Yet, EPA does not provide any analysis for why three percent of emissions may be significant, identify at what level GHG emissions are significant, or explain why it believes it is unnecessary for it to identify a threshold for significance. The Agency simply declares these emissions to be significant. This is arbitrary and capricious.

6.0 EPA MUST INCLUDE A PROVISION IN SUBPART OOOOA TO ENSURE THE TAILORING RULE FRAMEWORK IN THE PSD AND TITLE V PERMITTING RULE APPLY AND THAT METHANE ALONE WILL NOT TRIGGER PSD OR TITLE V PERMITTING

Pollutants that are subject to the prevention of significant deterioration (“PSD”) permitting program are identified in EPA’s PSD rules in the definition of “regulated NSR [new source review] pollutant.” 40 C.F.R. §§ 52.21(b)(50), 51.166(b)(49). That definition has four Subparts, the second of which covers pollutants regulated under section 111. The fourth Subpart covers “[a]ny pollutant that is otherwise subject to regulation under the Act.”

EPA’s Tailoring Rule limits the number of sources required to obtain PSD permits due to GHG emissions under the *fourth* Subpart of the “regulated NSR pollutant” definition. Similarly, the Tailoring Rule in the Title V rules limits the number of sources required to obtain Title V permits by incorporating the term “subject to regulation” in the definition of major source. After the Supreme Court’s decision in *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (and subsequent remand proceedings before the D.C. Circuit),² part of the original Tailoring Rule remains in effect. A source cannot trigger PSD and Title V permitting requirements solely because of its GHG emissions; only emissions of non-GHG pollutants can trigger PSD and Title V requirements. Moreover, where non-GHG emissions trigger PSD and Title V permitting requirements for a so-called “anyway source,” that source’s GHG emissions will be subject to PSD and Title V permitting requirements only if the source emits GHGs in excess of 75,000 tons per year of carbon dioxide equivalent.

In the PSD rules, the *second* Subpart of the “regulated NSR pollutant” has no Tailoring Rule equivalent in Part 51 or 52. EPA has recognized this gap and stated it intends to conduct a rulemaking to set a *de minimis* threshold for GHGs that would apply to all four Subparts of the definition for all types of sources. 80 Fed. Reg. at 64630. EPA has not yet conducted a rulemaking to address this issue, however.

² Per Curiam Order, *Coal. for Responsible Regulation v. EPA*, No. 09-1322 (D.C. Cir. Apr. 10, 2015), ECF Doc. No. 1546840.

Thus, when EPA finalized NSPS Subpart TTTT, which addresses carbon dioxide emissions from new electric generating units, it included language in Subpart TTTT to make clear that the “anyway” source framework applies to the second part of the “regulated NSR pollutant” definition. Similarly, the EPA included in the language a provision to make clear the “anyway” source framework applies in the Title V regulation as well. *See id.*

EPA must also ensure their action of naming only methane in Subpart OOOOa cannot trigger PSD or Title V permitting and instead that methane should be considered a surrogate for the existing group of six greenhouse gas pollutants. Such a fix was included in the final NSPS Subpart TTTT by adding language to clarify the pollutant being regulated by the Subpart is greenhouses gases in the form of a limitation on emissions of carbon dioxide. A similar clarification should be added to Subpart OOOOa, as well as a discussion in the preamble, to ensure methane on its own cannot cause a source to be considered major for PSD and Title V purposes and that a PSD major modification cannot be caused solely due to an increase in methane emissions.

API proposes the following specific rule language to correct the issue, modeled after NSPS TTTT:

Which pollutants are regulated by this Subpart?

(a) The pollutants regulated by this Subpart are greenhouse gases. The greenhouse gas standard in this Subpart is in the form of a limitation on emission of methane.

(b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

As further support for this clarification, in the preamble to the final Subpart TTTT, EPA recognized that EPA “will need to consider adding provisions like 40 CFR 60.5515 to other Subparts of part 60” until it undertakes the broadly applicable rulemaking it is considering. 80 Fed. Reg. at 64630. The Subpart TTTT approach should be taken in Subpart OOOOa because it would confirm in regulatory language that States do not need to amend their existing state implementation plans.

7.0 FOR AFFECTED FACILITIES WHERE REGULATION OF METHANE IN ADDITION TO VOC ACHIEVES NO APPRECIABLE ADDITIONAL REDUCTION IN METHANE EMISSIONS, THERE IS NO NEED OR JUSTIFICATION FOR METHANE OR GHGS TO BE REGULATED.

In the proposed rule, EPA admits that for some of the regulated affected facilities, direct regulation of methane accomplishes no further reduction in methane emissions than would occur through regulation of VOC alone. EPA recognizes that under its proposal, the same controls would be required for VOC and methane as are currently required for VOC under the 2012 NSPS. *See, e.g., id.* at 56610 (explaining

standards for centrifugal compressors and pneumatic controllers). EPA acknowledges that for sources in the production and processing segment of the oil and natural gas sector, certain stakeholders (including API) have stated that, as a result, the Agency should rely on VOC standards and not propose redundant methane standards that impose no additional control requirements and result in no additional emissions reductions. *Id.* at 56609. API maintains that position in these comments.³ There is no rational basis for taking the wholly discretionary action⁴ of regulating methane or GHGs from this part of the oil and natural gas sector where EPA would achieve no additional emissions reductions beyond those achieved through existing VOC standards. None of EPA's asserted reasons have merit, and therefore, EPA has not made a showing that revision of the standards is "appropriate," as required under section 111(b)(1)(B). For that reason, EPA must issue a new proposal that presents its rationale for why its revision is "appropriate."

First, EPA generally asserts that because the source category's methane emissions at current levels "contribute substantially to nationwide GHG emissions" and are "expected to increase," methane emissions "cannot be treated simply as an incidental benefit to VOC reduction." *Id.* at 56599. But there will be no further reductions in methane emissions from already-VOC-regulated sources if methane is regulated directly, so additional emissions reductions would not occur vis-à-vis current levels. Moreover, any attempted reliance on future emissions growth is speculative at present and cannot serve as a rational basis. Regulation must be grounded in reality, not hypotheticals.

Second, EPA contends that direct regulation of methane in addition to VOC "promote[s] consistency" such that all affected sources are subject to both VOC and methane standards. *Id.* But this "consistency" accomplishes no benefit in practice. Instead it will increase the compliance burden for affected facilities, without any beneficial environmental or health effect. For that reason, it is distinguishable from the Kraft Pulp Mill NSPS example that EPA cites, where emissions limits of already regulated sources under NSPS Subpart BB "were adjusted downward" to make them consistent with those in Part 63 Subpart S and thereby "ease[the] compliance burden for the sources." *See id.* at 56599 n.8.

EPA has not, and cannot, provide a rational basis for direct regulation of methane because regulation for the sake of regulation is never rational. Congress recognized as much in section 301(a) of the Clean Air Act, where Congress authorized the Administrator only to "prescribe such regulations as are *necessary* to carry out [her] functions." (emphasis added). EPA cannot meet that requirement here.

8.0 EPA'S STANDARDS THAT ACHIEVE NO ADDITIONAL REDUCTION IN EMISSIONS CANNOT MEET THE REQUIREMENT TO CONSIDER THE COST OF EMISSIONS REDUCTIONS.

As noted above, by EPA's own admission, the regulation of methane emissions from sources already regulated under Subpart OOOO for VOC emissions will achieve no additional emissions reductions. EPA therefore cannot meet the requirements for determining the "best system of emission reduction" (BSER) that the CAA requires.

EPA must "tak[e] into account the cost of achieving [emissions] reduction" in its BSER determination. CAA § 111(a)(1). Sources already regulated under Subpart OOOO for their VOC emissions will achieve

³ In the proposed rule, EPA "anticipates ... stakeholders will express their views during the comment period." 80 Fed. Reg. at 56609.

⁴ EPA recognizes that the regulation of additional pollutants is discretionary. *Id.* at 56599 & n.7.

zero additional emissions reduction and yet will incur additional costs to comply with new methane requirements. EPA cannot determine a standard to be BSER where it imposes costs yet achieves no reduction. That would be *per se* cost-ineffective.

9.0 THE PROPOSED RULE IS ARBITRARY AND CAPRICIOUS BECAUSE EPA FAILED TO CONSIDER THE IMPLICATIONS OF SECTION 111(D) OF THE CLEAN AIR ACT

EPA interprets section 111(d) of the Clean Air Act to apply to existing sources that would be regulated under a section 111(b) NSPS if the source were new, provided the source category and/or pollutant is not otherwise regulated under section 108 or 112 of the Act. *See* 80 Fed. Reg. 64662 (Oct. 23, 2015) (EPA's "Clean Power Plan" to regulate carbon dioxide emissions from existing electric generating units).⁵ Under EPA's interpretation, final promulgation of the proposed rule would trigger an obligation for the Agency to issue emissions guidelines for existing oil and natural gas sources under section 111(d).⁶ Assuming, for the sake of argument, that EPA's interpretation were permissible, the proposed rule should have to consider section 111(d) impacts. Yet, the proposed rule includes no reference at all to section 111(d) and no discussion of the potential regulatory implications to existing sources under section 111(d) by promulgating a NSPS for the oil and natural gas sector under section 111(b). As is plainly evident from the Clean Power Plan, regulation of existing sources under section 111(d) can and likely would have far greater potential impacts than the proposed standard for new sources. As a result, the Agency should have estimated the costs of regulating existing oil and natural gas sources in the proposed rule given its interpretation of the Act. EPA's utter failure to consider this important aspect of the decision to implement a NSPS renders the decision arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n v. State Farm Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has ... entirely failed to consider an important aspect of the problem....").

While EPA should have considered the impacts of the regulation of existing sources under section 111(d) as part of the proposed rule. The Clean Air Act does not impose a deadline on the Agency to propose emissions guidelines pursuant to section 111(d) once it has promulgated standards of performance for new sources under section 111(b). *See* CAA § 111(d). Moreover, because the proposed rule is legally flawed for the reasons described elsewhere in these comments, EPA would have no authority to adopt section 111(d) guidelines for oil and natural gas sources because the regulations under section 111(d) must apply only to "any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source." *Id.* § 111(d)(1)(A).

⁵ EPA's interpretation will be challenged in litigation over the Clean Power Plan. *See West Virginia, et al. v. EPA*, No. 15-1363 (D.C. Cir.).

⁶ API does not agree with EPA's interpretation of the statute presented in the Clean Power Plan that the Agency has authority to issue § 111(d) standards for affected facilities that are subject to § 112 standards. Rather, API asserts that if a source category is regulated under § 112, then EPA cannot regulate sources in that source category under § 111(d). *See* CAA § 111(d)(1)(A)(i). Because § 112 standards apply to the oil and gas sector, EPA lacks authority to issue § 111(d) standards for this sector.

10.0 EPA'S COST METHODOLOGY IS INCONSISTENT WITH ITS OWN "RATIONAL BASIS" TEST AND IS THEREFORE ARBITRARY AND CAPRICIOUS.

For some sources in the proposal, EPA finds that "cost-effective controls that can simultaneously reduce both methane and VOC emissions from . . . equipment . . . would *not occur* were we to focus solely on VOC reductions." 80 Fed. Reg. at 56599 (emphasis added). This methodological cost justification for regulating methane is inconsistent with EPA's own test for regulating an additional pollutant from a source category and is thus arbitrary and capricious.

In the proposal, EPA uses two different methodologies for assessing whether costs are reasonable. *Id.* at 56617. Under EPA's single pollutant approach, all of the costs are attributed to only one pollutant (i.e., methane or VOC) because the same controls are used for VOC and methane. *Id.* Under the second approach—known as the "multipollutant cost-effectiveness" approach—the annualized costs are apportioned based on the relative reduction of each pollutant by a control. *Id.* If application of either the individual pollutant approach or the multipollutant cost-effectiveness approach results in a determination that regulation imposes reasonable costs, EPA concludes that control is cost-justified. For at least certain sources, EPA justifies controls based on the multipollutant approach alone, as the costs evaluated under the single pollutant approach would not be reasonable.⁷

EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." *See* 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. *See id.* at 56636.

11.0 EPA SHOULD NOT REQUIRE THE USE OF ELECTRONIC REPORTING UNDER SUBPART OOOO AND SUBPART OOOOa.

On March 20, 2015, EPA proposed the "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards" (80 FR 15099, March 20, 2015). EPA should not require the use of electronic reporting under Subpart OOOOa since the system is not yet established and application of EPA's Compliance and Emissions Data Reporting Interface (CEDRI) to the oil and natural gas industry has unique challenges.

As mentioned in our June 18, 2015 comment letter on EPA's proposed requirements for electronic reporting, the proposed electronic reporting approach is in conflict with Subpart OOOO (and proposed Subpart OOOOa) requirements. As a result, a requirement to use EPA's electronic reporting tool should not be finalized at this time. Given the overlapping relevance to the unique challenges under Subpart OOOOa for electronic reporting, a copy of our June 18, 2015 comments is included as Attachment B.

EPA is proposing that the annual reports required by this Subpart be submitted through CEDRI starting 90 days after a template is available. Because of the unique operations of this industrial category, we see several problems with applying CEDRI as proposed, and API requests that these concerns be resolved before these new requirements are finalized for Subpart OOOO or Subpart OOOOa.

⁷ API's review of the proposed rule finds only one such example—EPA's determination that a semi-annual monitoring and repair program for fugitive emissions at well sites imposes reasonable costs under the multipollutant approach but not under the single pollutant approach. 80 Fed. Reg. at 56636.

Under this proposal the Subpart OOOO and Subpart OOOOa annual reports required by §60.5420(b) and §60.5420a(b) respectively must be submitted electronically once a template is available. Under Subpart OOOO and Subpart OOOOa, each regulated item is treated as a separate affected facility; however, they are reported together in the annual report. The individual affected facilities are identified in the annual report in different ways (often by their latitude and longitude) but not necessarily by the site where they are located, since there often is no site address and the affected facility (e.g., well) may be the only thing at that location. That is why Subpart OOOO does not require that all types of affected facilities be linked with a particular site (e.g., Subpart OOOO requires wells and storage tanks be identified by their longitude and latitude).

As we understand it, the CEDRI system links reports to the site at which they are located. Identifying each site separately in CEDRI would require deconstruction of the annual report as currently specified in Subpart OOOO (a change which was not proposed), imposing very large unjustified burdens that have not been considered and that are inconsistent with the promulgated reporting requirements of Subpart OOOO. For instance, one member company reports they have approximately 8,000 such sites and another member reports upwards of 20,000 sites. Although not all of the sites currently require reporting under Subpart OOOO, there may be hundreds of thousands of sites in petroleum upstream operations as new wells are drilled and new equipment is added to existing sites.

The CEDRI requirement to link every affected facility to a site could therefore require thousands of reports and responsible official certifications for each current Subpart OOOO report.

API, therefore, requests that the CEDRI system be modified to accept Subpart OOOO and OOOOa annual reports as currently specified in §60.5420 of Subpart OOOO and not require linking the reports to particular sites and that the proposed amendments of Subpart OOOO and Subpart OOOOa not be finalized until those revisions are completed.

Subpart OOOO and Subpart OOOOa require that the annual report be certified, as does the CEDRI system, however, these Subparts have a specific definition of “certifying official” that is different from the definition on the CEDRI webpage, and API therefore requests that the final revision to Subpart OOOO clarify that the certifying official for CEDRI reports is the one defined in §60.5430 of Subpart OOOO and §60.5430a of Subpart OOOOa. Furthermore, no additional certifications should be required than are currently required by Subpart OOOO or Subpart OOOOa without notice and comment rulemaking that addresses this specific issue.

For these reasons, API asks that EPA make CEDRI system and Electronic Reporting Tool (ERT) allowed alternatives to submitting hardcopy or PDF reports, at least for several years, until all of the operability and integration issues can be resolved.

As part of time afforded under a phase-in approach discussed above, API is committed to work with EPA on mechanisms to efficiently enable use of the CEDRI system for the oil and natural gas industry (e.g. develop mechanisms to support reporting of multiple affected sources at a time as is currently done on a regional basis by operators).

12.0 THE CONTROL DEVICE TESTING AND MONITORING COMPLIANCE ASSURANCE REQUIREMENTS ARE NOT APPROPRIATE

12.1 Oil and Natural Gas Production Sites are Unique from Traditional Stationary Sources

The sources covered by the current Subpart OOOO and the proposed Subpart OOOOa, particularly those in the production segment, are unique from typical stationary sources covered by NSPS in that they are small sites, located in remote areas, dispersed from each other (often requiring an hour or more travel time between regulated sites), and typically unmanned. These sites lack the infrastructure of power,

communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. Because EPA has “force fit” the testing, monitoring, and other compliance assurance requirements designed for traditional stationary sources to the oil and natural gas industry, the proposed testing and monitoring requirements result in unnecessary burden without a commensurate benefit. Sections 12.1.1 through 12.1.3 briefly describe some of the unique aspects of the oil and natural gas industry. Sections 12.2 and 12.3 provide specific examples of the inappropriateness of these requirements and provide recommendations that will ensure compliance and environmental benefit without creating unnecessary and costly burdens on the industry.

12.1.1 Oil & Gas Production Operating Conditions are not Steady State

Oil and natural gas operations are unique due to the dependence on the naturally occurring underground nature of the resource being harvested. This section summarizes some of those unique characteristics and the impact on emission control devices (primarily combustion control devices).

Unlike most industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas is located thousands of feet below the surface and must flow in two or three phases to the surface. Ideally, this flow would occur at a relatively steady rate at a velocity fast enough to suspend small droplets of produced water and liquid hydrocarbons during the vertical ascent to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system. This may occur at times but it is not typical.

As production declines and velocity in a vertical pipe decrease, the small droplets start to move slower than the gas and combine into larger and larger droplets. These eventually form slugs of liquid that must be pushed up the pipe. The increasing back-pressure on the reservoir reduces in-flow, production, and hence velocity. As backpressure on the reservoir increases and the velocity continues to decrease, the liquid column in the wellbore can stop the gas flow until the gas pressure below the slug increases sufficiently to push the liquid to the surface. The management of these wellbore liquids is a major concern throughout the life of a well that mandates changes in both down hole and surface equipment. The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible.

12.1.2 Production Separator Operation

The purpose of the two or three-phase production separator is to separate the two or three-phase flow from the well, to ensure that only natural gas goes to the gathering system and to ensure only liquid hydrocarbons and produced water are sent to their respective storage vessels. Separators are sized to give sufficient “residence time” to allow the separation of phases to take place. Since the actual mix of gas, oil (or condensate), and produced water varies randomly with time, it is impossible to predict when or how often a given control-action will occur.

The flow into the separator is made up of the fluids that the reservoir produces at any given moment, as modified by the transport of those fluids to the surface. The liquid levels in the separator are maintained by valves (often called dump valves) on the separator outlets to the oil/condensate storage vessel and the produced water storage vessel (although liquid collection systems are sometimes used in lieu of a storage vessel). The dump valves are sized to handle the highest flow rate of liquid that the separator can be expected to receive. Because of the highly variable flow conditions, separators normally provide flow to

storage vessels in short spurts, typically lasting only seconds, to maintain the required liquid levels, and dump cycles may be separated by many minutes, hours, or even days.

12.1.3 Closed Vent System Flow Rate

Gas flow from the storage vessel into the closed vent system (CVS) predominantly results from flashing vapors (resulting from the spurts of liquids from the separator) and dwarfs the working and standing emissions typical from storage vessels (that occur between spurts). However, the CVS and control device must be sized sufficiently to handle the peak vapor volumes expected. Measuring the flow in CVS causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology (see Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas, Attachment C). Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds and be able to go back to zero just as quickly. The hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients. Currently for minerals accounting purposes the Federal Government and States do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology.

12.2 The Proposed Testing, Monitoring, and Other Compliance Assurance Requirements are Inappropriate for the Oil and Natural Gas Industry

12.2.1 The NESHAP-Level Approach For Compliance Assurance Is Inappropriate And Unrealistic For Oil And Natural Gas Production Sites

For the most part, EPA has copied the full MACT control device and compliance assurance requirements in NESHAP HH (40 CFR 63, Subpart HH) for Subpart OOOOa rather than craft cost-effective requirements tailored to address the unique situations related to oil and natural gas operations. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for Subpart OOOOa. Furthermore, Subpart OOOOa applies to dispersed locations that do not have electricity, may not have automation and may have limited space for existing automation to accept additional inputs into their programmable logic controller (PLC) and remote transmitting unit (RTU) space. Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH major sources, it is not appropriate to arbitrarily invoke compliance assurance requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for an NSPS regulation for the control of volatile organic compounds (VOCs) or methane.

Examples of the inappropriateness of invoking MACT compliance assurance requirements for NSPS include but are not limited to:

- §60.5417a(a) requires Continuous Parameter Monitoring System (CPMS) for control devices. EPA did not include the cost for installing, maintaining, and operating a CPMS in any of the impact assessments for this rulemaking. Most affected facilities in the production segment of the industry will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work cannot be performed by lease operators during normal inspection visits.

- §60.5417a(f)(1) requires the operator to establish minimum and/or maximum values for the operation parameter and operate the control device within the range. As explained in section 12.3.4, this requirement is impractical to meet for either manufacturer certified combustors or combustion controls where the performance test is performed in the field, but for different reasons. This requirement is the same as the NESHAP HH requirement located in §63.773(d)(5)(i)(a) & (c).
- Similar to above, §60.5417a(d)(1)(iii) requires that a flare pilot, used for centrifugal compressors and pneumatic pumps controls, be assured by a heat detection sensor and continuous controller. Section 60.5417a(a) makes this appear to be a CPMS requiring all of the assurance provisions of (c), (f) and (g). This requirement is essentially identical to the one in §63.773(d)(3)(i)(C) with the CPMS general provisions located §63.773(d)(1) requiring to meet (4), (6), & (7). Requiring a pilot monitoring device to meet the requirements for a CPMS is extremely burdensome for any rule but is unprecedented for NSPS regulations.
- Compliance Demonstrations (§60.5412a) and Test Methods (§60.5413a). EPA reference methods that determine percent reduction on a mass basis, as is specified in Subpart HH major source control requirements where Subpart OOOOa does not specify percent reduction of a pollutant on a mass basis. This causes the measurement of volume that is not practical or in many cases possible with the types of operations and fluid flows typical for these facilities.

12.2.2 Compliance Assurance Requirements Are Unnecessarily Complex

The use of extensive cross referencing both between sections concerning control devices (i.e. §60.5412a for initial compliance requirements, §60.5413 for performance testing, and §60.5417a for continuous monitoring requirements) and various test methodologies renders the requirements confusing and nearly impossible to follow. These segmented requirements unnecessarily add to the compliance burden and are likely to lead to errors and misunderstanding. Companies that operate stationary sources subject to EPA's NSPS and NESHAP regulations may have personnel whose sole job is to understand EPA's complex requirements. However, many companies regulated by Subpart OOOOa are primarily small businesses that do not have this luxury. API members, along with the consultants they have hired, have had difficulty in interpreting the requirements for control devices as proposed. There is still not agreement of interpretation within API with many of the provisions.

12.2.3 API Agrees With EPA's Proposal To Maintain The Streamlined Monitoring Requirements For Storage Vessels But Disagrees With The Proposed Addition Of Performance Testing Requirements

During the "reconsideration" of Subpart OOOO (proposed April 12, 2013, finalized September 23, 2013 and continued until this proposal), EPA found that "compliance monitoring provisions and field testing provisions of the final rule may not be appropriate for this large number of affected storage vessels, which is much greater than we had expected and with many in remote locations." Further, EPA found it appropriate to only include "streamlined monitoring and continuous compliance demonstration requirements to provide assurance" (see 78 FR 22134). The streamlined monitoring provisions consisted of monthly sensory (i.e. OVA) inspections and monthly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 15 minute period.

In this proposal, EPA has retained the "streamlined monitoring provisions" (see §60.5412a(d)(1)(i) through (iii)). Despite the fact that nothing has changed since 2012 with regard to the number of storage vessels and their remote location, EPA reinstated the performance testing without responding to most of the concerns raised during the reconsideration process. API supports EPA's decision to maintain the

“streamlined monitoring provisions” in lieu of most of the continuous monitoring requirements finalized in 2012. Additionally, API appreciates and supports EPA’s revision to the outlet concentration compliance method of §60.5412a(d)(1)(iv)(B) raising the TOC (minus methane and ethane) level from 20 ppmv to 600 ppmv. However, EPA did not address API’s significant concerns regarding the percent pollutant reduction method of §60.5412a(d)(1)(iv)(A) or any of the performance testing provisions of §60.5413a or continuous monitoring provisions of §60.5417a. API continues to believe that unaddressed provisions are unnecessarily complex and stringent.

12.2.4 The Compliance Assurance Requirements For Centrifugal Compressors Are Not Justified

During discussions with EPA, API was told that the control device monitoring and testing requirements of the 2012 rule were retained since few centrifugal compressors were expected to require control and that most of these affected sources would be located at more developed facilities, such as Natural Gas Processing Plants. While this statement may sufficiently explain the retention of some of the monitoring provisions, it does not address the practical considerations in complying with the performance test provisions and the identifying parameter ranges required for the continuous monitoring. Although there are a few centrifugal compressors that require control, almost all of the control devices also control gases from other sources, such as storage vessels, that bring in the impracticality of flow measurement discussed in Section 12.1.3.

12.2.5 The Proposed Compliance Assurance Requirements For Pneumatic Pumps Are Filled With Problems

There are many issues with the proposed compliance assurance provisions for pneumatic pumps. Following are three major issues associated with the compliance assurance requirements. These are discussed at length in Section 24.0.

Compliance Assurance Requirements of an Existing CVS/Control Device Should Not Change

EPA determined that the benefit of controlling the discharge of a pneumatic pump was insufficient to justify the installation of a control device, thus the requirement to only connect new pneumatic pumps to existing CVS/control device. Further, EPA only considered the cost of piping the pump discharge to the CVS but did not include costs for additional compliance assurance (see Section 22.2.1 – 24.3.1). Most control devices are expected to be installed due to state minor source NSR permits. These permits have their own compliance assurance requirements which are significantly different than those for OOOOa centrifugal compressors, resulting in significant additional cost. These additional costs have not been included in EPA’s cost/benefit analysis, cannot be justified with the low emission reduction benefits achieved, and do not provide additional environmental benefit. Thus, API recommends that EPA not any require additional compliance assurance requirements in OOOOa be applied for a CVS or control device when a pneumatic pump is connected to it (see Section 24.2).

Pneumatic Pumps Are Located Near Storage Vessels, Not Centrifugal Compressors

As stated above, EPA believed that few centrifugal compressors were expected to require control, and these few are mainly expected to be at natural gas processing plants. Therefore, EPA proposed that pneumatic pumps at natural gas processing plants must have no natural gas emissions, thus tying centrifugal compressor compliance assurance requirements to pneumatic pumps is not logical. However, pneumatic pumps are most often located at well sites and small compressor stations that are more likely to have controls devices installed to control emissions from storage vessels. Well sites do not have the communications infrastructure that would be required to be installed under the centrifugal compressor compliance assurance requirements (see §60.5417a(a)) making these additional requirements an even greater burden. As noted above, API believes that no additional compliance assurance requirements

should be added beyond what are already required for the existing control device. However, if EPA decides to add new compliance assurance requirements when a new pneumatic pump is connected to an existing control device, it should be the storage vessel compliance assurance requirements, not those for centrifugal compressors.

Clarification is Needed When a Pneumatic Pump Must be Connected to a CVS/Control Device

There is significant uncertainty on when a pneumatic pump must be connected to a control device. Control device is an undefined term and defining it is a necessary first step to resolve this issue (see Sections 13.0). Another great source of uncertainty is when a boiler or process heater is considered a control device and when it is part of a process (see Section 13.0). API believes that pneumatic pumps should not be required to be routed to a boiler or heater.

Further, the control device and the pneumatic pump may be owned/operated by two different companies (i.e. chemical injection for gathering system corrosion control at a well site). In this case, even though a control device is at the location, it is not available to the owner/operator of the pneumatic pump (see Section 24.4.5). Finally, instances occur where it is not technically feasible to connect the pneumatic pump to the control device (see 24.3.2).

12.3 Compliance Assurance Requirements for Combustion Control Devices

12.3.1 The Proposed Compliance Assurance Requirements May Discourage The Use Of Enclosed Combustors

The design of enclosed combustors intrinsically yields higher destruction efficiencies than flares because of the heater style of burner and protection from cross wind. The enclosure also creates an induced draft of air that aids complete combustion of heavier (higher molecular weight) hydrocarbon streams. Additionally, the enclosure isolates the flame from sight that may cause concern to some members of the public. These benefits sometimes encourage industry to install the high cost internal (i.e., "enclosed") combustor instead of the commonly used open flame flare. Enclosed combustors do have the ability to be performance tested where the open nature of flares do not. It is ironic that EPA is requiring substantially more burdensome monitoring and performance testing requirements for enclosed combustors in the proposed rule even though these combustors have greater environmental benefit than flares. It is counterproductive for the environment to disadvantage enclosed combustors with compliance assurance requirements just because they are technically feasible. EPA should encourage the use of enclosed combustors by using the same visual inspection requirements as with flares for opacity.

12.3.2 The Continuous Parameter Monitoring System (CPMS) Provisions For Centrifugal Compressors And Pneumatic Pumps Are Inappropriate

API supports the EPA's proposal to not require CPMS or other monitoring systems on storage vessel combustion control devices. As will be discussed below, API does not understand the value of the CPMS requirements that are proposed for combustion control devices for centrifugal compressors and pneumatic pumps. Installing and operating a continuous pilot and the use of visual inspection for opacity (as required for storage vessel affected facilities in §60.5412a(d)(1)(ii) & (iii)) is adequate to assure complete combustion and encourages the use of enclosed combustors. The only additional compliance assurance procedure should be to check the air vent per manufacture recommendations any time opacity is seen (as required in §60.5417(h)(1)(A)).

12.3.3 The Determination Of CPMS Range Determinations In Field Performance Test Is Technically Impractical

Section 60.5417a(f)(1) requires that for any parameter that requires CPMS monitoring, the operator must determine the minimum or maximum value of the parameter that continuously achieves the performance requirements in §60.5412a(a). Section §60.5417(f)(1)(i) requires a performance test performed by the operator to determine the minimum or the maximum operating parameter based values measured during the performance test. However, the operator has limited ability to adjust the conditions of the process to test the control device. The performance test must be run at the conditions available when the test is scheduled. The operator is unable to vary the operating conditions to determine the limit of the operating parameter as a manufacturer does when conducting a shop test on an enclosed combustor. Section 60.5417a(f)(1)(i) cannot practically be complied with, because the performance test cannot be completed at the full range of conditions for which the control device will be operated. Furthermore, this extends far beyond what EPA requires for testing control devices at area sources under NESHAP HH, which applies to nearly all oil and natural gas production sites. In fact, the requirements approach the NESHAP HH requirements for major sources like natural gas processing facilities. For NSPS at a remote, unmanned site, it is more reasonable to test the device during current operating conditions.

12.3.4 It Is Not Technically Feasible To Meet The CPMS Flow Measurement Requirements For Manufacturer Certified Combustion Control Devices

Paragraph 60.5417a(f)(1)(iii) requires that for manufacturer certified enclosed combustors, an operator must install CPMS measurement on the inlet flow to assure that the flow is not greater than the maximum or less than the minimum that the manufacture specifies. The CPMS requirements only apply to centrifugal compressors (that have relatively stable flow rates) and pneumatic pumps, but the same control devices will often be controlling emissions from storage vessels as well. As explained in section 12.1.3, the measurement of flow from storage vessels is very difficult even when only the normal emissions must be measured. Requiring both the minimum and maximum range to be measured, it is doubtful if a single instrument can measure both values. The pump flow as well is intermittent, low pressure, low velocity/flow and difficult to measure as discussed in Section 24.0.

12.4 Compliance Options For Combustion Control Devices

Section §60.5412a specifies four compliance options that can be used to assure compliance with the control requirements of storage vessels (see §60.5412a(d)(1)(iv)) and centrifugal compressors and pneumatic pumps (see §60.5412a(a)(1)). These options include (1) percent reduction of the pollutant, (2) limiting the concentration in the exhaust, (3) maintaining a minimum combustion zone temperature, and (4) inject the stream into the flames zone of a boiler or process heater. Comments are provided below on options 1 and 2. As explained in Section 13.0 below, option 4 is a direct conflict with the definition of "route to a process" in both Subparts OOOO/OOOOa and NESHAP HH. Therefore, API recommends that EPA remove §60.5412a(a)(1)(iv) and §60.5412a(d)(1)(iv)(D).

12.4.1 Percent Reduction Of Pollutant Should Be Based On Volume Not Mass And Should Not Requirement Measurement of Flow To The Control

The standards for centrifugal compressors, pneumatic pumps, and storage vessels each require a percent reduction.

- For centrifugal compressors, §60.5380a(a)(1) requires that methane and VOC emissions be reduced by 95.0 percent or greater
- For pneumatic pumps, §60.5393a(b)(1) requires that natural gas emissions by 95.0 percent, and

- For storage vessels, §60.5395(a)(2) requires that VOC emissions be reduced by 95.0 percent

Note that none of these standards specify the basis for the 95.0 percent reduction. However the initial compliance demonstration requirements in §60.5412a(a)(1)(i) for centrifugal compressors and pneumatic pumps and in §60.5412a(d)(1)(iv)(A) for storage vessels add the requirement that this percent reduction in emissions be determined on a mass basis. The associated performance test requirements of §60.5413a(b)(3) for calculating percent reduction by weight of pollutants requires the measurement of flow to the control device. The requirements of §60.5412a and §60.5413a were predominantly adopted from the major source NESHAP requirements in Subpart HH that specify control requirements of 95 percent reduction by weight. While mass reduction requirements may be appropriate and specified by Subpart HH, they are burdensome and impractical for NSPS requirements for small, remote, dispersed and unmanned production facilities.

Section 12.1.3 above describes the many difficulties encountered when attempting to measure the flow of vapors to a control device at oil and natural gas production sites. EPA has not explained the reason for prescribing the reduction of pollutants to be determined by weight in the compliance demonstration and performance testing requirements when a mass destruction was not specified as part of the control requirements. Conditions of intermittent high/low flow conditions, variable and turbulent flow, and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API requests EPA to determine percent of TOC reduction through a carbon balance methodology similar to that described in EPA's Flare Efficiency Study Report.⁸

The requirement in §60.5413a(b)(3)) should be modified to require reduction of TOC emissions by 95% on a volumetric concentration basis using a "carbon balance" methodology for analysis of the exhaust stack effluent from an "enclosed combustion device" being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO₂ and O₂, and 10 for CO should be specified for testing of the stack effluent gas. The CO₂ measured using Method 3A should be adjusted downward by the latest published atmospheric CO₂ concentration, as reported from the Mauna Loa monitoring site by NOAA's Earth System Research Laboratory, multiplied by the ratio of O₂ measured in the stack effluent as compared to the ambient O₂ content of 20.8 volume %. (3A measured CO₂ (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O₂ (ppmv)/208,000 (ppmv) ambient O₂ concentration)).

The percent pollutant reduction or destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$$(\text{CO}_{2c} + \text{CO}) / (\text{CO}_{2c} + \text{CO} + (3 * \text{TOC}))$$

Where:

CO_{2c} = CO₂ ppmv concentration measured in the stack via method 3A minus the ambient CO₂ ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

⁸. Technical Report "EPA-600/2-83-052" "FLARE EFFICIENCY STUDY" by Marc McDaniel, July 1983 (see http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf).

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following Table 12-1 shows this calculation and outcome for an assumed stack effluent composition:

Table 12-1 Assumed Stack Effluent Composition

Outlet CO ₂	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O ₂	150,000	
Ambient O ₂	208,000	
Ambient CO ₂	388	
Outlet CO _{2c} from combustion	29,720	Outlet CO ₂ - ((Ambient CO ₂ X (Outlet O ₂ /Ambient O ₂))
Destruction Efficiency	99.70%	(CO _{2c} + CO)/(CO _{2c} + CO + (3*TOC))

12.4.2 API Supports EPA's Revision Of The Concentration Of Exhaust Limit To 600 PPMV

In response to "reconsideration petitioners", EPA proposed to revise the combustion device compliance option of demonstrating an exit concentration of less than 20 ppmv to 600 ppmv as propane (see §60.5412a(a)(1)(ii) and §60.5412a(d)(1)(iv)(B)) as being more representative of a 95% reduction in VOC. EPA solicited comments on this proposed amendment (see 80 FR 56645). API agrees that an exit concentration of 600 ppmv is more representative of a 95% destruction efficiency and supports this proposal.

12.5 EPA Must Revise The Provisions Related To Flares Subject To §60.18

API has several issues with the requirements in Subpart OOOO and proposed Subpart OOOOa that are related to the requirement that flares used as control devices meet §60.18 of the general provisions. One of these issues, which is addressed in Section 12.5.2, is related to the inadequacy of the requirements related to flares for storage vessel affected facilities. There are also many technical challenges that make it infeasible to comply with the §60.18 provisions that occur both at production sites and natural gas processing plants. These issues, along with recommended regulatory changes, are discussed in sections 12.5.2 through 12.5.6.

12.5.1 The Proposed Requirements For Flares Are Inconsistent And Inadequate, Particularly As They Apply To Storage Vessel Affected Facilities

The proposed regulatory compliance requirements, with respect to flares and their conformance to §60.18 of the General Provisions of 40 CFR part 60, are reasonably clear for centrifugal compressor affected facilities. The construction of those requirements in Subpart OOOO both generally results in adoption of §60.18(b) requirements for flares yet innovatively allows flexibility to adopt new or superior flare technologies through performance testing. However, this is not true for storage vessel affected facilities. Clarity for applicable requirements, with respect to flares and their conformance to §60.18, for storage vessel affected facilities could be accomplished in a similar manner.

For example, §60.5412(a)(3) of Subpart OOOO clearly identifies a flare designed and operated in accordance with the requirements of §60.5413(a)(1) as an acceptable control device for centrifugal compressors affected facilities. However, there is no analogous allowance of the use of a flare as an acceptable control option in §60.5412(d) for storage vessel affected facilities. An addition to §60.5412(d) of a requirement, similar to §60.5412(a)(3), specifying that a flare must be designed and operated in accordance with the requirements of §60.5413 would result in the same clarity for storage vessel affected facilities. An additional sentence could be added to the introductory paragraph in §60.5413 to say that the performance test exemptions for flares in §60.5413(a)(1) are applicable to both storage vessel and centrifugal compressor affected facilities. The change recommended above to the introduction to §60.5413 is necessary without regard to the flare provisions as the requirements in §60.5413(d) and (e) for manufacturer tested devices also apply to storage vessel affected facilities.

Similarly, for Subpart OOOOa, an addition to §60.5412a(d) of a requirement, similar to §60.5412a(a)(3), specifying that a flare must be designed and operated in accordance with the requirements of §60.5413a would carry the clarity for storage vessel affected facilities to Subpart OOOOa. An additional sentence in the introductory paragraph in §60.5413a is unnecessary because it includes applicability to centrifugal compressor affected facility, pneumatic pump affected facility, and storage vessel affected facility as proposed.

These changes would result in clear and appropriate requirements for flares used as control devices for storage vessel affected facilities. Specific recommendations for these amendments are provided in Section 12.5.6.

While the recommendations above will provide clarity that flares are acceptable control devices for storage vessel affected facilities, as well as clarify the requirements of these flares, there are numerous issues associated with the broad application of the provisions of §60.18 to flares to Subpart OOOO and OOOOa affected facilities. These issues are discussed in the following sections. Additional regulatory recommendations are provided to rectify these problems and allow the continued use of flares in the oil and natural gas industry.

12.5.2 There are Technical Challenges in Meeting the §60.18 for Flares in Oil and Natural Gas Production and Gas Processing that Must be Addressed

Flares are an attractive control device choice for the oil and natural gas industry due to their simplicity, reliability, lower maintenance requirements, and effectiveness in reducing organic compound emissions. The requirements in §60.18 of the 40 CFR part 60 General Provisions were developed by EPA to generally apply to flares. However, these requirements were developed and refined based on industrial flares primarily used at large petroleum refineries and petrochemical plants. As discussed above in section 12.1, there are unique aspects of the oil and natural gas industry that require accommodations in the control device requirements. The following sections suggest changes related to the application of the §60.18 provisions to Subpart OOOO and OOOOa affected facilities that will allow the compliant use of flares in the oil and natural gas industry without compromising their effectiveness in reducing VOC and methane emissions.

12.5.3 The Use Of Electronic Ignition Systems Should Be Allowed

§60.18(c)(2) requires that flares be operated with a flame present at all times, as determined by monitoring using a thermocouple or any other equivalent device to detect the presence of a flame. API continues to believe that an option to use electronic ignition systems should be allowed for the oil and natural gas sector. Since oil and natural gas operations are not always steady state, flares with continuously lit pilots (24/7) can unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emission stream being burned. An attractive and

effective alternative is to allow the use of electronic ignition systems that ensure a flame is present whenever emissions are being routed to the flare.

In addition, many oil and natural gas production sites are remote and unmanned. In these situations, an electronic ignition system has proven to be a more reliable means of ensuring there is always a flame when emissions are routed to the flare rather than attempting to maintain a continuous pilot.

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903.⁹ Presumably this was published because EPA approves of the design, recognizes its benefits and wanted to promote its use in industry. EPA should not forfeit the benefits of this control technology enhancement by disallowing its use. As an established and preferred technology by EPA in the Natural Gas STAR program, operators should not have to petition EPA for approval.

API recognizes the need to ensure that the electronic ignition system is working and that a flame is present at all times when emissions are being routed to the flare. API believes that the existing requirements in §60.18(f)(2) already provides an appropriate requirement: Paragraph (e) states that “Flares used to comply with provisions of this Subpart shall be operated at all times when emissions may be vented to them” and (f)(2) states “The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.” With the simple amendments to §60.5413(a) and §60.5413a(a) and §60.5417(d)(1) and §60.5417a(d)(1) shown below, EPA can allow the use of auto-ignition devices while also ensuring compliance.

Specific recommendations for these amendments are provided in Section 12.5.6

12.5.4 Testing Should Not Be Required To Demonstrate Compliance With §60.18(f)(4)

Paragraph 60.18(f)(4) requires that the volumetric flow rate be “*determined by Reference Methods 2, 2A, 2C, or 2D as appropriate*”. As a result, a test will be required for every flare used to comply with Subparts OOOO and OOOOa. As discussed in section 11.1, the measurement of flow is impractical and potentially impossible at oil and natural gas production sites. In addition, even if these technical challenges were ignored, EPA’s estimate of impacts did not include significant costs that would be incurred by the industry.

While not specifically referenced in this paragraph, the provisions in §60.8(c) require that performance tests be conducted on conditions that reflect “*representative performance of the affected facility*.” During representative conditions, the exit velocities of the flare at oil and natural gas sites will never approach 400 feet per second. This can be easily demonstrated through the use of engineering calculations rather than testing or direct measurements. Specific changes must be made to §60.5413(a) and §60.5413a(a) to correct this situation. The recommendations for these amendments are provided in Section 12.5.6

The technical challenges related to volumetric flow rate are not unique to storage vessels in the production segment. At many gas processing plants, pressure release devices are often routed to flares along with the emissions from other equipment. While there are typically no emissions from these pressure release devices, they can develop leaks. Under Subparts OOOO and OOOOa, these pressure relief devices are subject to §60.482-4a(a) of NSPS Subpart VVa. Since these pressure release devices are routed to a “closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device”, they are exempt from the leak detection and repair (LDAR) requirements in §60.482-4a(a) and (b), but are subject to the closed vent system and control device requirements of §60.482-10a. Paragraph §60.482-10a(d) requires flares to comply with §60.18. The leaks that would occur from these pressure release devices would be very low, meaning that the

⁹ <http://www3.epa.gov/gasstar/documents/installelectronicflareignitiondevices.pdf>

difficulties in measuring the flow to these flares results in costly test programs that are entirely unnecessary given the extremely low flow rates. Therefore, API also recommends that the volumetric flow rate for these flares also be allowed to be determined using engineering calculations. API suggests that paragraphs be added to §60.5401 and §60.5401a to address this technical infeasibility situation. These recommendations for these amendments are provided in Section 12.5.6

12.5.5 Sonic And Other Flares Operated During Maintenance, Startup, Shutdown, And Malfunction Situations Should Not Be Required To Comply With The Exit Velocity Requirements In §60.18(c)(4)

In EPA's September 18, 2015 Federal Register Notice (80 FR 56646), EPA specifically requested comment on the use of pressure-assisted flares in the oil and natural gas industry.

As EPA notes, pressure-assisted, or sonic, flares are designed to exceed §60.18's maximum exit velocity of 400 feet per second. As a result, they do not meet §60.18. Some facilities with potential large volume flows may utilize sonic flares, such as those included at onshore natural gas processing facilities, to control emissions in times of emergency, upsets, or maintenance. Sonic flares offer advantages over traditional low-pressure flares in some applications. For example, some designs allow smokeless operation over the entire operating range without any assist medium. This is a clear benefit for remote areas. Additionally, with no assist medium, energy usage and its related emissions are minimized and there remains no potential for steam/air over-assist. Some designs also offer less low frequency noise and less flame visibility in low profile designs. Sonic flares operate with destruction efficiencies that are at least as equivalent to, and generally greater, than low pressure flares.

Pressure-assisted (sonic) flares are not designed for continuous use, but instead operate in emergency, upset or maintenance situations where high volumes and pressures are sent to the flare. In some scenarios, pressure relief valves subject to LDAR monitoring are routed to sonic flares for the purpose of emergencies or upsets. Maintenance events are also routed to these flares in some cases.

However, a conflict with the velocity limits in §60.18(c)(3) is not limited to the case of pressure-assisted flares. Velocity limits for commonly used low-pressure flares (ground or elevated steam-assisted, air-assisted or unassisted flares) are achievable under representative day-to-day conditions. However, velocity limits for even low-pressure flares can be exceeded under conditions that approach the hydraulic capacity of flares. General application of §60.18(b) to a Subpart without the inclusion of §60.11 or an alternative exemption for periods of emergency, upset or maintenance is problematic.

Flares designed under §60.18(b) may exceed velocity limits during periods of emergency, upset or maintenance. In order to remain in compliance with the velocity limits, flare operators would need to install additional flare capacity for SSM events either by replacing an existing flare or adding additional flares. Therefore, the exemption from the §60.18 maximum velocity requirements should not be limited to pressure-assisted flares, but rather to all flares during periods of emergency, upset, or maintenance. As discussed in section 12.5.7 below, there is substantial evidence that indicates that the performance of flares will be maintained at these higher velocities.

Therefore, in order to allow the use of sonic flares and traditional flares designed under §60.18(b) for the oil and natural gas industry, EPA should exempt flares from the maximum velocity requirements in §60.18(c)(4).

Revisions are needed to §60.5413(a) and §60.5413a(a), and to §60.5401 and §60.5401a to allow the use of flares in these situations. The recommendations for these amendments are provided in Section 12.5.6.

In addition, changes are needed to Table 3 of both Subparts OOOO and OOOOa. The recommendations for these amendments are provided in Section 12.5.6

12.5.6 Recommended Rule Changes To Address Issues With Flare Requirements

The following are the recommended rule changes related to the issues discussed above that are related to the requirement that flares used for Subparts OOOO and OOOOa comply with the requirements of §60.18.

Subpart OOOO

§60.5401

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

§60.5412

(d) Each control device used to meet the emission reduction standard in §60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable, and (d)(4). As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).

* * * * *

(3) You must design and operate a flare in accordance with the requirements of §60.5413.

(34) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5413

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor and storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A-7, to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

§60.5417(d)(1)

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

Table 3 to Subpart OOOO of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

Subpart OOOOa

§60.5401a

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

§60.5412a

(d) Each control device used to meet the emission reduction standard in §60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable, ~~and (d)(4)~~. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

* * * * *

(3) You must design and operate a flare in accordance with the requirements of §60.5413a.

~~(34)~~ You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes ~~from working or flash losses~~ are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5413a(a)

(1) A flare that is designed and operated in accordance with §60.18(b), ~~with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section~~. You must conduct

the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

- (i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),
- (ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and
- (iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

§60.5417a(d)(1)

- (iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

Table 3 to Subpart OOOOa of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

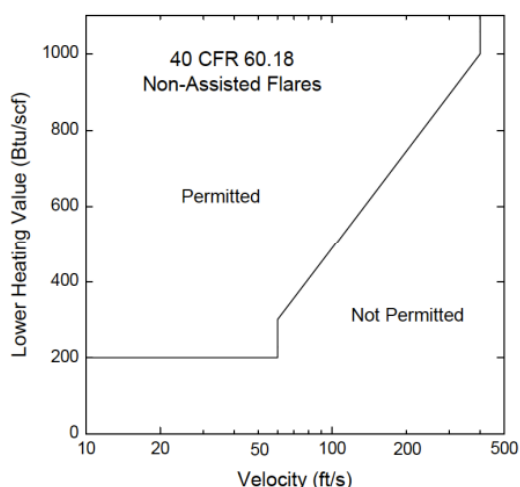
12.5.7 Velocity Limits In §60.18(C)(3) Are Unnecessary To Ensure High Destruction Efficiency In Flares

There is substantial evidence that flares operating with higher exit velocities are effective in reducing emissions. Following is a discussion of this evidence.¹⁰

Origins of Existing Flare Velocity Limits

The velocity limits in 40 CFR 60.18 were originally promulgated on January 21, 1986 and are graphically depicted below. The figure shows flame exit velocities in feet-per-second (fps) along the x-axis and lower heating value of the waste gas in Btu/scf along the y-axis. A minimum heat content is required of 200 Btu/scf for unassisted flares or 300 Btu/scf for assisted flares up to 60 fps, where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps is reached.

¹⁰ Adapted from “A Review of Flare Velocity Limits in 40 CFR 60.18 and 63.11.” Prepared for American Petroleum Institute October 26, 2014 by Scott Evans.

Figure 12-1 Current EPA Flare Velocity Limits

This relationship was developed following a series of EPA sponsored tests conducted in the 1980's that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel¹¹ test and the 1984 Pohl¹² test. The focus of the 1985 Pohl¹³ and 1986 Pohl¹⁴ studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 feet per second (fps) have been included in this analysis.

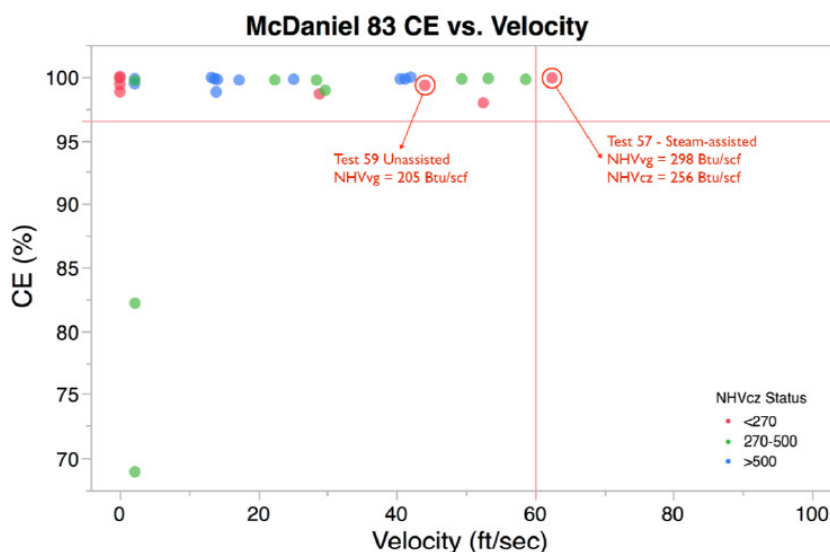
The 1986 limits appear to originate with only four data points from these tests – the average value at the upper limits of each study. The 60 fps, 300 Btu/scf limit for steam-assisted flares was set based on a single data point -- McDaniel 1983¹¹ test 57. The 200 Btu/scf limit for unassisted flares was also set based on a single data point – McDaniel test 59. These tests were performed on an 8.6-inch steam-assisted flare fueled with a propylene/nitrogen mix. The data are shown in Figure 12-3. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHVVG) is less than 270 Btu/scf, green dots indicate test runs with NHVVG between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

¹¹ McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983

¹² Pohl, J., et. Al.; "Evaluation of the Efficiency of Industrial Flares: Test Results," EPA-600/2-84-095

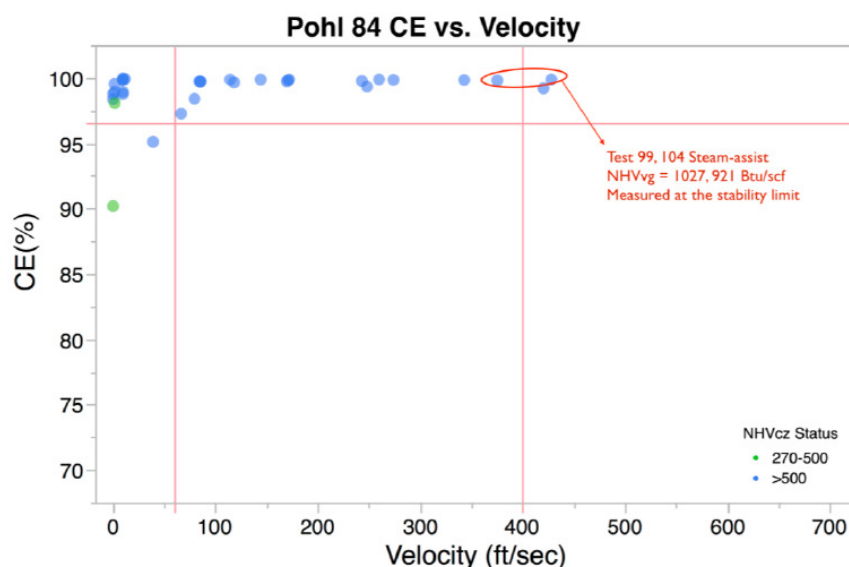
¹³ Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Composition," EPA-600/2-85-106, September 1986

¹⁴ Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: H2S Gas Mixtures and Pilot Assisted Flares," EPA-600/2-86-080; September 1986

Figure 12-2 A Comparison of Combustion Efficiency vs Velocity for McDaniel 1983

McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

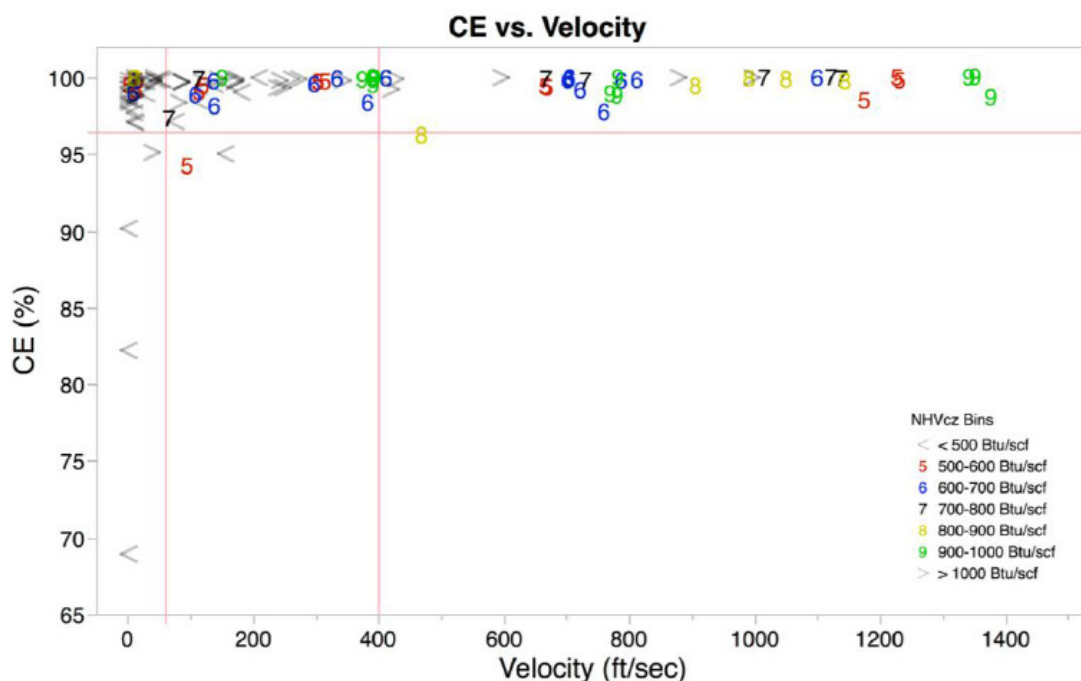
The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.¹² That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in Figure 12-3. The data are binned by heat content, where green dots indicate test runs with combustion zone net heating value (NHVCZ) between 270 and 500 Btu/scf and blue indicate test runs with NHVCZ greater than 500 Btu/scf.

Figure 12-3 A Comparison of Combustion Efficiency vs Velocity for Pohl 1984

Similarly to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

High Velocity Flare Test Data Figure 12-4 shows all data from publically available high velocity flare tests as of October 2014. Some low velocity data are also included to the extent that they were measured during a test series including high velocity data. Data includes the 1980's flare studies referenced above as well as more recent studies (Marathon Garyville¹⁵ and Dow¹⁶). This data is similarly displayed based upon combustion efficiency (CE) as a function of exit velocity in fps. The data is binned by NHVCZ in groups of 500 Btu/scf. Only data with NHVCZ > 270 are included.

Figure 12-4 A Comparison of Combustion Efficiency vs Velocity for All Publically Available High Velocity Flare Tests binned by NHVCZ Range



Almost all of the low velocity data that also have low CE have NHVCZ values less than 500 Btu/scf. Additionally, virtually all of the test runs with velocity greater than the current limit of 400 fps, were conducted at NHVCZ values less than the current 1,000 Btu/scf limit. This graph clearly shows that high combustion efficiency above the current limits is not only possible, but that it is assured based upon available test data.

¹⁵ Clean Air Engineering, "Performance Test of Steam-Assisted and Pressure-Assisted Ground Flare Burners with Passive FTIR – Garyville," March 21, 2013

¹⁶ Varner, V., Kodesh, Z.; "Emission Testing of Pressure Assisted Flare Burners," Presented at the American Flame Research Committee 2014 Industrial Combustion Symposium, September 2014

Flame Stability

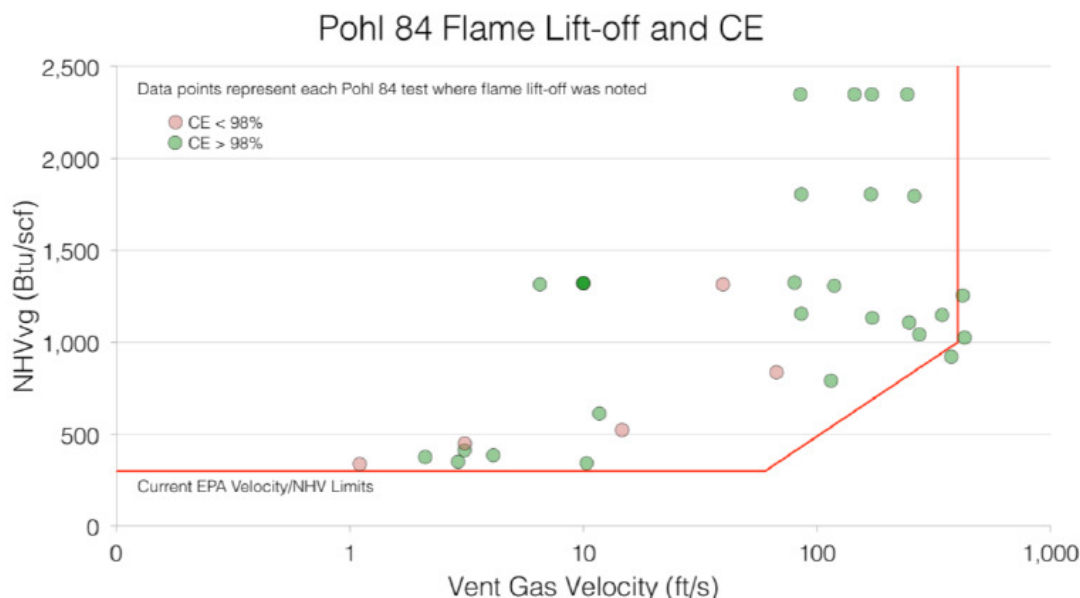
The claim is often made that the reason velocity limits are necessary is to ensure “flame stability.” However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

“The term *flame stability* simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out.” [Pohl 84, p2-3]

Others¹⁷ have defined flame stability in terms of “lift-off”, a conditions that occurs when the base of the flame detaches from the flare tip.

While there is no doubt that Pohl’s definition results in unacceptable flare performance, there is little evidence that flame lift-off has any correlation either positive or negative to combustion efficiency. Figure 12-5 shows every data point from Pohl 84 where flame lift-off was noted in the report.

Figure 12-5 A Comparison of Flame Lift-Off and Combustion Efficiency from Pohl 84



Twenty-seven of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 12-5 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl’s definition that a high velocity flame is stable until it goes out.

There is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the “snuff point.” Both the Pohl 84 data and the Marathon Garyville

¹⁷ Shore, D., “Improving Flare Design: A Transition From Art-Form to Engineering Science,” Presented at AFRC-JFRC October, 2007.

data were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

Conclusion

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This paper reviewed data from the data sets used to establish those federal regulatory velocity limits as well as recent high velocity flare test results.

All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion efficiency (>96.5%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.

The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive.

12.6 Control Devices in Compliance with NESHAP Subpart HH Should be Exempt

There is a high likelihood that a site with equipment subject to MACT HH (40 CFR 63, Subpart HH) will also have affected facilities subject to Subpart OOOOa. In these situations, it is possible a control device will be used to comply with both MACT HH and Subpart OOOOa. This could result in the same control device being subject to requirements under both Subparts that are not entirely aligned. In order to avoid these needless requirements, API requests that §60.5412a clearly state that control devices that are subject to 40 CFR 63, Subpart HH are exempt from the requirements in Subpart OOOOa. Following is recommended regulatory language to clarify this exemption.

§60.5412a

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. **Control devices in compliance with the requirements in §63.771 of 40 CFR 63, Subpart HH are exempt from the requirements in this Subpart.**

12.7 While EPA Has Been Testing Various Manufacturer Devices, the Process has been Slow

NSPS Subpart OOOO (40 CFR 60, Subpart OOOO) and MACT HH and HHH (40 CFR 63, Subparts HH and HHH) allow for the use of combustion devices that are tested by the manufacturer which eliminates the need for source testing at the site. EPA maintains a list of approved Combustion Control Devices¹⁸ on their website. EPA has also stated that the current "approved list" will be adopted for OOOOa. API requests confirmation of this in the response to comments to reflect EPA's intent.

However, there are several issues with the approval process. First, more than half of the devices listed on the website are characterized as "under review", and they have maintained this status for a long period of time (one or more years). According to one manufacturer, the approval process should be less than a month. The NSPS will result in the need for many more combustion devices to control existing sources, which increases the need to step up the approval process. Closer inspection revealed that incomplete test reports may be a possible cause for achieving "under review" status, and therefore it may not be a fault of

¹⁸ <http://www3.epa.gov/airquality/oilandgas/pdfs/mantesteddevices.pdf>

EPA's process. However, EPA needs to investigate the cause for these long delays in this approval process and correct them.

Second, manufacturers report that relief from propene testing would decrease the testing costs considerably. It makes no sense to require propene testing for combustion devices that will be used at oil and natural gas production facilities as there are insignificant amounts of double bond hydrocarbon compounds in natural gas. API requests that §60.5413a(d)(2) be modified as follows to allow the use of propane to expedite the approval process.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

13.0 EPA MUST ELIMINATE THE CONFUSION AND CONFLICT ASSOCIATED WITH "CONTROL DEVICE" AND "ROUTED TO A PROCESS"

It is clear from the proposed control requirements for centrifugal compressors (§60.5380a(a)(2)), pneumatic pumps (§60.5393a(b)(4)), and storage vessels (§60.5395a(b)(1)) that "route to a process" was intended as an alternative to a control device. For example:

§60.5380a(a)(2): If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

However, the definitions and provisions related to "control device" and "routed to a process" are inconsistent and confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters. The following sections highlight these issues and suggest a solution that will eliminate the confusion and conflicts without any reduction in the effectiveness of the rule.

13.1 Definition Of "Routed To A Process" Should Be Clarified

Section 60.5430 of proposed §60.5430a of Subpart OOOOa includes the following definition:

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

The use of "routed to a process" is clear as used in §60.5365a(e)(3) in connection to a VRU, as these emissions are recycled and incorporated into a product.

This definition also unmistakably applies to situations where the emissions are combusted in a boiler or process heater. There are three different ways in which hydrocarbon vapors can be fed into a boiler or process heater for destruction – 1) vapors routed to the flame zone, 2) vapors routed to the fuel system as a primary fuel, and 3) vapors routed to the combustion air supply as a secondary fuel. For all three of these methods of introducing hydrocarbon emissions into a boiler or process heater the emissions are clearly "consumed in the same manner as the material that fulfills the same function in the process". Further, the emissions are "transformed by chemical reaction into materials that are not regulated

materials". However, Subparts OOOO and OOOOa are not as clear how this definition applies for boilers and process heaters. EPA must clarify this linkage between "routed to a process" and boilers and process heaters throughout the final rule.

Despite the fact that EPA defined routed to a process/route to a process in a manner that would include all situations when emissions are routed to a boiler or process heater, there are instances throughout both Subpart OOOO and OOOOa where EPA appears to consider boilers and process heaters as control devices. For example, in §60.5412(a)(1) and §60.5412a(a)(1), EPA includes boilers and process heaters in a parenthetical describing a combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater). Similarly, this same parenthetical description of enclosed combustion device in in §60.5412(d)(1) and §60.5412a(d)(1). Further, in the list of "control devices" exempted from performance testing in §60.5413(a) and §60.5412a(a), there are several specific boiler and process heater examples that are exempted.

One of these exemptions, specifically §60.5413(a)(3) and §60.5412a(a)(3), exempts boilers or process heater "into which the vent stream is introduced with the primary fuel or is used as the primary fuel." These seems to indicate that EPA draws a distinction between the three situations described above where emissions are routed to a boiler or process heater (even though they are all three clearly covered by the definition of "routed to a process").

The recommended changes discussed below resolve this conflict.

13.1.1 NSPS SUBPARTS VV AND VVa INCLUDE THE CONCEPT OF "FUEL GAS"

In the rulemakings for NSPS Subparts VV and VVa, EPA has addressed this same basic situation in a clear and reasonable manner. For example, §60.482-4a(c) states that:

"Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section."

Further, Subpart VVa includes the following related definitions.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

API believes that this precedent can be utilized to improve the clarity in Subparts OOOO and OOOOa. This recommendation is provided below.

13.1.2 Recommended Change To Definition Of "Routed To A Process Or Route To A Process"

API recommends that the following changes be made to the definition of routed to a process or route to a process" in both Subparts OOOO and OOOOa.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

API further recommends that the following definition of fuel gas be added.

Fuel gas means gases that are combusted to derive useful work or heat.

13.2 Definitions of “Control Device”, “Combustion Device”, and “Combustion Control Device”

The confusion discussed above between related to boilers and process heaters and routed to a process is exacerbated by the fact that neither Subpart OOOO or Subpart OOOOa define control device. In addition to this situation that needs to be corrected, the Subpart OOOOa proposal for pneumatic pumps make defining “control device” critical. This is discussed later in Section 24.0.

As discussed in section 13.1.2, the definition of “routed to a process” clearly includes routing emissions to a boiler or process heater to be consumed, yet both Subparts OOOO and OOOOa discuss boilers and process heaters as control devices in other places.

In addition, the situation is further confused as EPA uses the terms “combustion device”, “combustion control device”, and “enclosed combustion control device” in an arbitrary manner that further confuses the situation. None of these terms are defined in proposed Subpart OOOOa.

In conjunction with the recommended definitions in section 13.1.2, **API offers the following definitions to be added to §60.5430a of OOOOa.**

Control device means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this Subpart.

Combustion control device means a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.

Enclosed combustion control device means a combustion control device with an enclosure such that the flame is not an open flame.

This definition of control device, along with the definition of “routed to a process or route to a process” recognizes that routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors. Thus, routing pneumatic pump exhaust or compressor blowdown gas to be used as a fuel gas would not make heaters or boilers using these streams part of a control device.

In addition, the following changes are needed throughout Subpart OOOOa to rectify the inconsistent usage of these terms throughout. These changes also address the changes related to boilers and process heaters and “routed to a process.”

§60.5412a

(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility or §60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a **combustion** control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

(1) Each combustion **control device** (~~e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater~~), except for a flare, must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iviii) of this section.

* * * * *

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(d) Each control device used to meet the emission reduction standard in section §60.5395a(a) for a storage vessel must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a **combustion** control device model tested under section §60.5413a(d), which meets the criteria in section §60.5413a(d)(11) and §60.5413a(e).

(1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

* * * * *

~~(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

§60.5413a

(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (75) of this section.

~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~

~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~

(42) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.

~~(53)~~ A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.

~~(64)~~ A performance test is waived in accordance with §60.8(b).

~~(75)~~ A **combustion** control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

* * * * *

(b)(3)(iv) ~~Reserved If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

§60.5417a

~~(b) Reserved You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~

~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~

~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~

~~* * * * *~~

~~(d)(1)(iv) Reserved For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or $\pm 2.5^{\circ}\text{C}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~

~~* * * * *~~

(d)(1)(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the **combustion** control device. The monitoring instrument must have an accuracy of ± 2 percent or better. The flow rate at the inlet to the combustion **control** device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the **combustion** control device.

Similar requirements exist in Subpart OOOO and Subpart HH that should also be modified because of their conflict with the "route to a process" provisions.

14.0 THE PROPOSED BY-PASS DEVICE REQUIREMENTS ARE NOT REASONABLE AND WERE NOT JUSTIFIED BY EPA

EPA has added requirement to install a flow indicator and audible alarm and initiate notification via remote alarm to the nearest field office on the bypass device that could divert the stream away from the control device or process to the atmosphere. There are numerous issues with this proposal:

1. It appears to create retroactively revised requirements for existing sources under Subpart OOOO, which should not be done.
2. The proposal in Subparts OOOO and OOOOa is inconsistent.
3. EPA did not include the cost of the alarm and notification system in the cost analysis for Subparts OOOO or OOOOa.
4. Requiring notification presumes that automation with remote transmission capabilities is already present on site which may not be the case. If existing automation and remote transmission capabilities don't exist it would be unreasonable to require installation of these for purposes of monitoring a bypass device.
5. The verification processes are different for secured and non-secured devices.

These issues are discussed below in sections 14.1 through 14.4. The by-pass requirements should be the same for non-secured and secured devices, only indicate an alarm onsite, and the requirements should not

retroactively revise Subpart OOOO. Table 14-1 illustrates the existing rule language and points out inconsistencies and Table 14-2 provides recommended rule changes.

14.1 Retroactive Equipment Requirements

EPA appears to have retroactively changed the requirements under §60.5411(a)(3)(i)(A), §60.5411(c)(3)(i)(A), and §60.5416(c)(3)(i) to require that an alarm must be transmitted to the nearest field office since these rules apply to sources installed between August 23, 2011 and September 18, 2015. Previously, for compressors, there must only be an alarm with no indication of the location and for storage vessels there was an option for an alarm on site or remote alarm. Subpart OOOO currently reads:

§60.5411(a)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is **capable of taking periodic readings as specified in §60.5416(a)(4) and sounds an alarm** when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. **[Emphasis Added]**

§60.5411(c)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere **that sounds an alarm, or, initiates notification via remote alarm to the nearest field office**, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. **[Emphasis Added]**

EPA has no authority under § 111 to impose retroactive requirements. Therefore, EPA must make it clear in the final rule that these new requirements apply only prospectively to newly affected sources. In any event, the additional cost of having to add the equipment, do the programming, and maintenance of a system not already in place to send a notification to the nearest field office was not included in the cost analysis as discussed further in Section 14.3. Please Table 14-2 see for proposed changes to the rule.

14.2 The Requirements Are Inconsistent for Bypass Devices for Subparts OOOO and OOOOa

The proposed requirements are inconsistent between Subpart OOOO and Subpart OOOOa and between the different affected sources. These inconsistencies lead to problems implementing the requirements. A facility may have an affected storage vessel and an affected pump with multiple alarm requirements. If these requirements remain in Subpart OOOO, the requirement should be consistent with Subpart OOOOa to avoid confusion. Furthermore, the requirement should be consistent between the affected sources (i.e., storage vessels, pumps, and compressors).

Please see Table 14-1 for further information on the inconsistencies between the two proposals and Table 14-2 for proposed changes to the rule.

14.3 EPA Did Not Consider the Cost of the Alarm and Notification Requirements

In the proposed non-secured by-pass device requirements, EPA did not consider the cost and technical feasibility of an audible alarm and notification via remote alarm at the nearest field office. A remote alarm at a field office does not add any additional environmental benefit where an onsite device meets the intent of the alarm requirements. There are several considerations for a field office to receive data from field locations including onsite equipment, programming, and installation and maintenance. Adding an alarm will require installation of new equipment requiring potentially a facility to be shut down and the equipment purged so that "hot work" can be performed to install the equipment which will result in additional emissions. Furthermore, a company would need a remote transmitter unit (RTU) installed or have an existing RTU with sufficient capacity to transmit a signal from the device to an operations center to notify the operations center. There are also cost associated with programming, installation, and

maintenance of the alarm. Equipment and installation costs are several thousands of dollars for each data point, per site, routed into a system, even if existing monitoring equipment is located onsite. Ongoing support and maintenance of the monitored parameter is required to sustain operation. EPA did not include any of these costs in the justification for the proposed requirements.

14.4 The Verification Process between Secured and Non-secure is Inconsistent

For bypass devices secured with a car-seal or lock-and-key type configuration, the requirement is for visual verification that the device is secured. The requirements for non-secured devices should be similar and only require verification if the alarm - whether audio or visual - has been triggered. Since there is a flow indicator present, the amount vented would be known. Please see Table 14-2 for proposed changes to the rule.

Table 14-1 Comparison of Regulation Text as Written

Purple text is an OOOOa change from the previous OOOO version, Blue is inconsistencies between 1) OOOO and OOOOa and 2) sources.			
OOOO Centrifugal Compressors	OOOOa Compressors, and Pumps	OOOO Storage Vessels	OOOOa Storage Vessels
§60.5411(a)(3)(i)(A) – Centrifugal Compressors You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	§60.5411a(a)(3)(i)(A) – Compressors, and Pumps You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger and audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).
§60.5416(a)(4)(i) – Compressors Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the	§60.5416a(a)(4)(i) – Compressors, and Pumps Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam	§60.5416(c)(3)(i) - Storage Vessels You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream	§60.5416a(c)(3)(i) - Storage Vessels You must properly install, calibrate and maintain a flow indicator at the inlet to the

Purple text is an OOOOa change from the previous OOOO version, Blue is inconsistencies between 1) OOOO and OOOOa and 2) sources.

OOOO Centrifugal Compressors	OOOOa Compressors, and Pumps	OOOO Storage Vessels	OOOOa Storage Vessels
steam away from the control device to the atmosphere.	away from the control device to the atmosphere.	away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).

Table 14-2 Recommended Rule Text Revisions for Bypass Requirements – Redline

Consistent Text			
§60.5411(c)(3)(i)(A) – Centrifugal Compressors You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5411a(a)(3)(i)(A) – Compressors, and Pumps You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420a(c)(8).	§60.5411(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered sounded according to §60.5420a(c)(8).

Consistent Text			
§60.5416(a)(4)(i) – Compressors Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere. You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5416a(a)(4)(i) – Compressors, and Pumps Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere. You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5416(c)(3)(i) - Storage Vessels . You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered sounded activated according to §60.5420a(c)(8).	§60.5416a(c)(3)(i) - Storage Vessels . You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered sounded activated according to §60.5420a(c)(8).

15.0 THERE IS UNNECESSARY OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

EPA proposes fugitive monitoring like requirements for closed vent systems, but also includes closed vent systems in the definition of Fugitive Emission Components. This results in CVS being subject to both closed vent system and fugitive emission component monitoring requirements in §60.5397a and §60.5416a. This creates a situation which is unnecessarily duplicative and redundant. Specifically, EPA has required both optical gas imaging monitoring for the tank cover and the closed vent systems under §60.5397a, as well the following under §60.5416a:

- Annual Method 21 (M21) monitoring and visual inspections for closed vent systems for centrifugal compressors and pneumatic pumps, and
- Monthly olfactory, visual, and auditory inspections for storage vessel covers and closed vent systems.

This could result in as many as three different leak detection programs at a single facility.

To avoid this conflict, API provides recommendations that will eliminate this overlap while still ensuring that emissions from leaks from closed vent system components are minimized. The problem and API's recommendations are discussed in detail in Sections 26.0.

16.0 THE PROPOSED EQUATION FOR CAPITAL EXPENDITURE IS NOT REPRESENTATIVE OF CURRENT ECONOMIC CONDITIONS.

16.1 The Proposed Equation Models Inflation Improperly, Potentially Accelerating Moving Sites From KKK To OOOO And Impacting Processing Plant Economics.

The original equation proposed by EPA in §60.5430a is the following; $A = B * Y$, where $Y = 1 - 0.575 * \log(1982 - X)$, X = the year and $B = 4.5$. This formula was modeled based on the inflation of the late 1970s and early 1980s. This inflation was much higher than that seen today. Simply inserting 2011 into this equation will unrepresentatively discount the value of B . API proposes that EPA use a Consumer Price Index (CPI) based equation to discount B (valued at 4.5% for our industry) as shown below:

$$Y = (\text{CPI of date of construction or reconstruction} / \text{CPI of date of component price data})$$

The component price data must be adjusted for inflation if it is not current data.

Figure 16-1 and Figure 16-2 depict a comparison of the two equations showing the value of A , the red curve using the proposed equation $Y = 1 - 0.575 * \log(2011 - X)$, and the blue curve showing the equation above using 2012 price data. This demonstrates that the equation proposed by the EPA unrepresentatively overstates the effect of inflation in terms of discounting the value of B . The second graph (Figure 16-2) shows that using $Y = 1 - 0.575 * \log(1982 - X)$, and 1982 as the date of component price data, the value of Y predicts inflation adequately for the late 1970s and early 1980s.

The effect of the improper use of inflation is that gas plants that are built after 1982 that were not designed to comply with the more stringent OOOO regulations will be forced to comply with OOOO with as little as one valve added to the process unit. Large replacements of "equipment" (as defined in the regulation) may be needed to comply with this change, and permanent plant shutdowns may occur as a result because these replacements are uneconomic. This could result in

increased flaring of wet gas and increased VOC emissions, or the shutting in of oil wells as a result.

In addition, EPA must ensure that the definition of expenditure is not retroactive to eliminate interpretation issues.

Figure 16-1 AAAGRP Discount from B = 4.5% Method Comparison (2011)

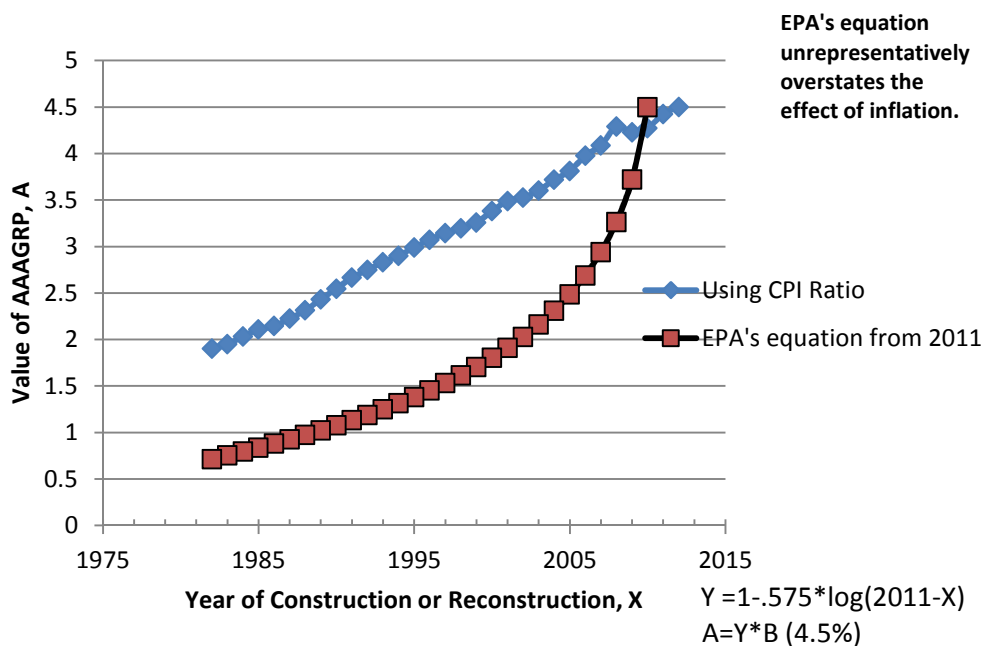
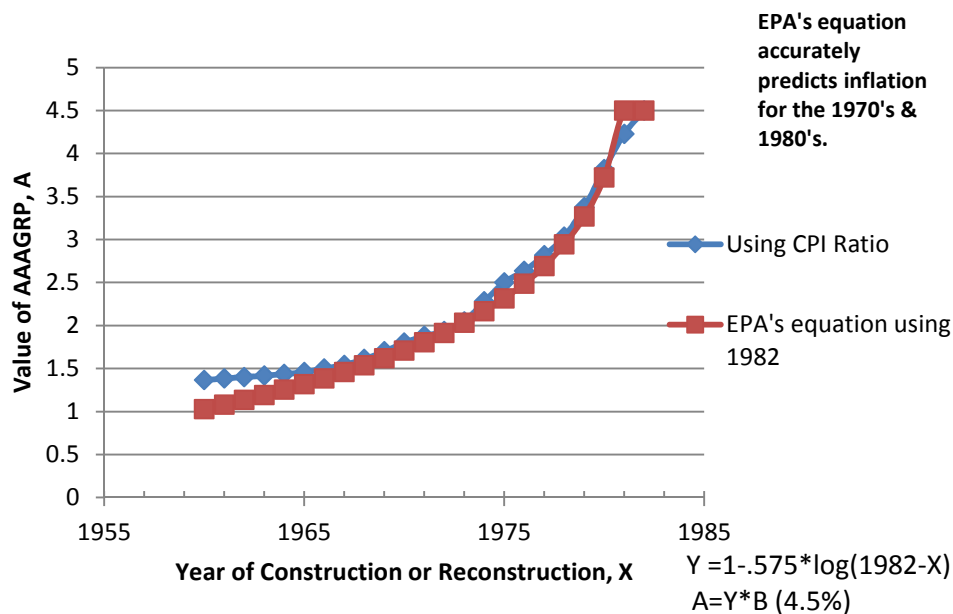


Figure 16-2 AAAGRP Discount from B=4.5% Method Comparison (1982).

17.0 API SUPPORTS EPA'S CONCLUSION REGARDING LIQUIDS UNLOADING REQUIREMENTS

Well-bore fluid dynamics and the portfolio of techniques, practices, and technologies that the industry uses to manage well-bore liquids are extremely complex. EPA has solicited significant comment on many aspects of liquids unloading operations within the preamble. Specifically EPA has sought comment (FR 56645) on:

- the level of methane and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading.
- characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions,
- demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation, and the effectiveness and cost of these techniques,
- whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future, and
- whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

API prepared information in Comments in response to EPA's White Paper on Liquid Unloading, which has been included as an attachment to this document as Attachment D. Due to inadequate time in the comment period, API refers EPA to this set of comments previously submitted.

API also reiterates its previous position that to adequately evaluate options to reduce venting of wells and the emissions that result, it is necessary to understand the reasons that wells are vented, alternatives to venting that will still provide for well-bore liquid loading management, and the envelope of conditions

where these alternatives are feasible. As EPA mentioned, emissions from liquids unloading are highly skewed and well-specific. This process is better left managed by companies under voluntary programs to manage, mitigate and implement. As such, API supports EPA's decision to not include requirements on liquids unloading.

18.0 NEXT GENERATION COMPLIANCE CONSIDERATIONS

18.1 EPA Should Not Be Seeking Comment Under Specific Rulemaking Packages For "Next Generation Compliance" Approaches That Could Be Expected To Have Broad Applicability.

The general next generation compliance topics for which EPA is seeking input in Section X of the preamble of the NSPS proposal (i.e. Use of Third-Party Verification, Third-Party Reporting, and expansions of Electronic Reporting) are broad issues that should not be addressed as part of sector-specific rulemakings.

Additionally, in whatever context considered, any Next Generation Compliance elements should clearly be shown to aid in the demonstration of compliance to EPA and not substitute non-EPA entities to perform EPA's responsibilities. The measures outlined in the preamble are unnecessarily punitive for a rule of general applicability.

18.2 Any EPA Actions Related To "Next Generation Compliance" Must Be Based Upon Proposed Rule Language.

No proposed rule text is provided that incorporates the issues on which EPA is soliciting comment in Section X of the preamble to the Subpart OOOO and Subpart OOOOa proposals. As a result, commenters do not have adequate clarity or notice of how the third party verification system would work and cannot ascertain whether the regulatory text would faithfully implement the concept. To resolve these problems, EPA would need to formally propose any third-party verification or third-party reporting requirements before finalizing any of them.

EPA has previously dealt with a similar situation and the corresponding need to provide comment on proposed requirements during the development of NSPS Subpart VVa and CISWI rules. *See* 73 Fed. Reg. 31,372, 31,373 (June 2, 2008) EPA determined that "[s]ection 60.482-11a is stayed from August 1, 2008 until further notice" because "these were first introduced in the final rule (indeed, with respect to connector monitoring, we explicitly stated in the proposal that we did not intend to address them in this rulemaking. Accordingly, certain facilities may be out of compliance with requirements for which they had no notice or time to come into compliance.") (emphasis added); *see also Portland Cement Ass'n v. E.P.A.*, 665 F.3d 177, 186 (2011) ("While we certainly require some degree of foresight on the part of commenters, we do not require telepathy. We should be especially reluctant to require advocates for affected industries and groups to anticipate every contingency. To hold otherwise would encourage strategic vagueness on the part of agencies and overly defensive, excessive commentary on the part of interested parties seeking to preserve all possible options for appeal. Neither response well serves the administrative process. Whatever warning EPA offered regarding CISWI was too vague and noncommittal to trigger a response from PCA. Indeed, as far as EPA did hint at its next steps, it suggested it would reevaluate the NESHAP standards after the CISWI definition was promulgated.").

18.3 Independent Third-Party Verification

In the preamble, EPA asserts that third-party verification “may” improve compliance¹⁹; however, EPA provides no information regarding how third-party verification would actually improve compliance. EPA does not explain why self-certification programs (like those under existing NSPS programs) would not work or why third party verification would improve compliance.

The following comments provide some additional comments discussing why API believes the options discussed in the preamble are neither legal nor necessary.

18.3.1 EPA Lacks Authority To Require Third-Party Verification.

As was noted in API's November 30, 2011 comments on the original Subpart OOOO proposal and EPA's request at that time for comment on innovative compliance options, EPA has again, in this rulemaking, not explained where it finds legal authority to impose a third-party verification requirement.

While EPA has authority to require such monitoring, recordkeeping, notification, and reporting requirements as are reasonably needed to assure compliance with Part 60 emissions standards. There is nothing on the face of the statute (and the statute cannot reasonably be construed as) authorizing EPA to require affected facilities to hire contractors to do EPA's work. EPA freely admitted in the 2011 Subpart OOOO proposal that assuring compliance with the well completion requirements would be “very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers.” As was the case in the original rulemaking, it again appears the purpose of the third-party verification requirement would be for the third-party verifiers to relieve burden on EPA. Simply put, EPA does not have authority under the CAA to require affected facilities to hire contractors to do work on behalf of the Agency.

Moreover, such a requirement would run afoul of the Anti-Deficiency Act. A third party verification requirement clearly would circumvent the limited Congressional budget appropriation for EPA enforcement activity. Such circumvention violates the prohibition against authorizing expenditures “exceeding an amount available in an appropriation or fund for the expenditure.” 31 U.S.C. §1341(a)(1)(A).

For these reasons, even with a re-proposal, EPA is without authority to impose a third party verification requirement.

18.3.2 EPA's Logic On Requiring Third-Party Verification Of The Adequate Design Of Closed Vent Systems Is Flawed And Such A Requirement Is Unnecessary.

EPA requests comments to whether they should specify criteria by which a professional engineer (PE) might verify that a closed vent system is designed to accommodate all streams routed to the facility's control system, or whether they might cite to current engineering codes that produce the same outcome.

The need for third-party review of well-pad designs is unnecessary if EPA believes that the proposed rule language is sufficiently clear. Further, API believe EPA could exceed its CAA authority under 111(b)(5) and (h) if such a requirement were to be finalized. The oil and natural gas industry regularly designs and builds some of the most sophisticated engineered systems in use anywhere. As such, the value derived from a third-party verification of system design would seem to only be to provide an extension of EPA's manpower and expertise. As noted above, such a requirement would run afoul of the Anti-Deficiency Act.

¹⁹ FR 56648: “...well-structured third-party compliance monitoring and reporting may further improve compliance.”

Oil and natural gas company engineering staff, with experience in the oil and natural gas industry and emissions control systems, and many with PE registration, are able to design systems effectively. This is especially true for modern hydraulically fractured shale oil and natural gas facilities, which are very different to the small single vertical well installations that dominated the industry in years past.

In addition to the above issues, the implementation of a third-party verification system would be complicated by the fact that any validation step would only have potential utility if it occurred prior to finalizing design and equipment construction. Specifically, any validation would need to take place prior to any required air permit applications are developed, adding time to what can already be a long process.

EPA should not attempt to expand any NSPS regulations by regulating the process or mechanical design of storage vessels or the closed vent systems through the use of third-party reviews of control devices or vapor recovery systems. Owners and operators are responsible for designing process equipment based on individual site process conditions and safety considerations. It would be a massive undertaking for EPA to attempt to write regulations regarding the specific "proper" design of storage vessels and closed vent systems. It is doubtful if EPA could provide enough flexibility in process and mechanical design of equipment regulations to cover all the unique process conditions at individual facilities.

Also, EPA has failed to take into consideration the availability of enough qualified consultants to perform process design analysis and compliance auditing. It is one thing to require third-party contracting, but quite another to find qualified contractors. EPA's proposal to limit perceived conflicts of interests would further shrink this limited pool of qualified contractors.

18.3.3 EPA's Request For Details On Pressure Monitoring Systems For Storage Vessels Is Unnecessary.

In the preamble, EPA requests comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices and thief hatches are not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system (FR 56649).

While recognizing the importance of proper design and operation of equipment, it is inappropriate for EPA to be considering this level of engineering detail as part of rulemaking. EPA has already specified requirements for inspecting closed vent systems and performing inspections to identify any leaks and these measures are adequate to address any potential issues related to how systems are designed and operated. Additionally, the design of well pads and tank batteries undergo engineering and safety reviews as part of their development. These reviews serve to ensure that materials flowing from wells are appropriately captured and routed as intended.

18.3.4 EPA Should Not Presume Industry Will Fail To Properly Implement The Proposed Leak Detection And Repair Requirements.

In Section X of the NSPS preamble, EPA solicits comments on an audit program of the collection of fugitive emissions components at well sites and compressor stations (FR 56649).

EPA explained the request for input on this matter based on the comment that they "have ample experience from our enhanced LDAR efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design." This analogy is flawed for numerous reasons, not the least of which is that most issues identified by the Air Toxics Enforcement Initiative relate to alleged failures related to the implementation of M21-based LDAR programs at facilities with thousands, and in some cases, up to hundreds of thousands of individual components subject to monitoring. It is noted that the scope of the oil and natural gas site operations are significantly different than any situations addressed in the enforcement initiative cited.

In the preamble (FR 56649-56650), EPA is quite detailed in describing the potential structure of an audit program for LDAR compliance as well as alternative auditor/auditing approaches with “less rigorous” independence criteria. Meanwhile, within the proposed Subpart OOOOa provisions, EPA has provided specific requirements related to the recordkeeping and work practices that must be followed as part of the leak detection requirements (see Section 27.0 of these comments for proposed provisions).

EPA is right that there will be challenges with the implementation of the LDAR requirements as proposed. See Section 27.0 of these comments for additional discussion of API's recommendations related to suggested improvements to the proposal rule to help address these challenges.

However, API believes it is unwarranted for EPA to assume or anticipate that industry will not comply with the regulatory requirements. As a result, it is inappropriate for EPA to preemptively require additional compliance measures that have been historically used as part of consent orders resulting from enforcement actions.

Even if EPA has statutory authority to require third party verifications, the same factors that make compliance assurance difficult and burdensome for State and EPA staff (such as geographically dispersed and remote locations) would make any use of third party verification costly to the regulated industry. In the proposed rulemaking and supporting documentation, EPA does not quantify or evaluate in the Regulatory Impact Analysis or proposed rule the costs associated with third party verification. In the GHG reporting program, EPA similarly proposed a third-party verification of the GHG report and declined to include in its final rule. See 74 Fed. Reg. 56,520, 56,5282-84 (October 30, 2009) (for a national program involving significant reporting such as the GHG reporting program, third-party verification was not the preferred approach). Specifically, EPA expressed concerns that a third party verification program: (1) would require EPA to establish third-party verification protocols; (2) would require EPA to develop a system to qualify and accredit third party verifiers; and (3) would require EPA to develop and administer a process to ensure verifiers do not have conflicts of interest. EPA thought that setting up a third-party program would slow down implementation of the rule. EPA also estimated that the first year of the program (with a third-party verification requirement) would cost \$42 million. GHG reporting rule and Subpart OOOOa would cover a similar scope and thus raise similar concerns as were raised in the GHG reporting rule. Accordingly, any action by EPA to incorporate verification into Subpart OOOOa must progress through a formal rulemaking process with proper assessment of cost-benefit of the additional requirements.

18.3.5 Transparency And Public Access To Information Resulting From Potential Auditing Provisions (FR 56650).

“EPA seeks comment on whether, and to what extent, the public should have access to the compliance reports, portions or summaries of them and/or any other information or documentation produced pursuant to the auditing provisions. EPA is also considering the approach it should take to balance public access to the audits and the need to protect Confidential Business Information (CBI). To balance these potentially competing interests, EPA is reviewing a variety of approaches that may include limiting public access to portions of the audits and/or posting public audit grades or scores to inform the public of the auditing outcomes without compromising confidential or sensitive information. EPA seeks comment on these transparency and public access to information issues in the context of the proposed auditing provisions.”

As stated above, API believes a requirement to use third-party auditing would exceed EPA's CAA authority, is unnecessary and any such program would face many changes to design and implementation. Even if EPA has the authority, it is necessary to include clear requirements in the rulemaking proposal regarding what information would be required to be submitted to the EPA or made available upon request.

18.4 Third-Party Data Reporting (e.g. Vendors)

18.4.1 EPA's Concept Of Having Control Device Vendors Provide Direct Submittals To The Agency Is Both Flawed And Unnecessary.

In Section X of the preamble, EPA solicits comment on potential third-party approaches such as the “post card” reporting described above that could be implemented to streamline and enhance compliance (FR 56651).

In the preamble, EPA appropriately acknowledges the limitations to how such an approach might work for the oil and natural gas sector:

“We understand the issues for this sector, with making the “postcard” model work as we envisioned. One of the issues is related to the granularity of the reporting by the manufacturer as compared to the reporting by the source to the EPA or delegated authority. For example, the manufacturer may only know that they sold 500 units of a particular control device, but may not know where it is actually installed. Lack of a unique “user ID” being reported by both sides can limit the utility of the postcard model in this instance.”

Requiring manufacturers to provide data to EPA regarding the number of control devices sold to different companies adds no value and could even likely be a source of confusion to reconcile which specific piece of equipment went where. Further, in many cases where the same model control device is installed in many locations, what matters is how that equipment is operated on site, not what serial number is on a particular control device.

For example, when an owner or operator purchases a “certified control device” from a vendor, the owner would be required to submit the model and serial number to the Agency. Additionally the vendor would be required to submit the same information, thereby confirming what the owner had reported. This is unnecessary burden on both the operator and the vendor, and is unprecedented in its duplicative reporting. As noted above, owner/operators will often buy units in bulk and not install these units for months or even years. This will cause unnecessary tracking and verification of installations against vendor-supplied data to EPA. The serial numbers of equipment are available at all times and if a question is ever raised about the unit, the Agency could then contact the vendor with any questions for verification. Having dual reporting will continually lead to confusion and unnecessary time spent reconciling equipment versus reporting.

In the preamble, EPA states:

“...a primary concern is that an owner or operator would install a control device, and not conduct a performance test, claiming that they installed a device listed on the Oil and natural gas page. We believe that we can build on the success of GIS imbedded digital photos for green completions (“REC PIX”), already in the rule, by developing a similar requirement for installed manufacturer tested control devices. Enhancing the records and reports by requiring specifics of the control device (make, model and serial number) and requiring the digital picture, will allow us to match a particular control device at a specific location with control device models listed on the Oil and natural gas page. Having this information electronically reported to CEDRI will further enhance our ability to evaluate compliance with the rule.”

API questions the success EPA claims regarding the use of GIS imbedded digital photos for green completions (“REC PIX”), already in the rule. Many API member companies are not utilizing the photo – an optional approach for recordkeeping – for affected gas wells. API disagrees strongly with EPA's assertion that widespread misrepresentation by industry is or will be a problem. EPA is adding burden

when they will not gain any more benefit from requiring a photo versus seeking submittal of the make and model of the control device.

EPA further states:

“While we are soliciting comment on third-party reporting by combustor vendors directly to the EPA, we propose to require that owners or operators include information regarding purchase of a pre-tested combustor model in their Notice of Compliance Status as part of the first annual report following the compliance period in which the combustor commences operation. The information would include (1) make, model and serial number of the purchased device; (2) date of purchase; (3) inlet gas flow rate; (4) latitude and longitude of the emission source being controlled by the combustor; (5) digital GIS and date stamp-imbedded photo of the combustor once it is installed; and (6) certification of continuous compliance. The owner or operator would be required to submit information to CEDRI in lieu of a field performance test.”

The above statement is misleading; the use of the photo is optional, consistent with the reduced emission completion option. The proposed rule includes the following language under §60.5420a(c)(5)(vi)(G):

“As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.”

18.5 Electronic Reporting - EPA should not require the reporting of data related to rule compliance in multiple locations since this adds cost with no benefit and violates the First Amendment

In the preamble, EPA solicited comments on potentially requiring owners and operators of affected facilities to report quantitative environmental results on their corporate maintained web sites (FR 56652):

“The EPA requests comment on whether all owner and operators should be required to do this, or only a subset (e.g., based on size of entity, complexity or number of operations, web presence, etc.) and what data we should require them to report; keeping in mind that monitoring and reporting requirements that may be sufficient for government regulators may be insufficient for the public. Government regulators may be satisfied with a regulation that requires a facility to monitor specified parameters (e.g., operating temperature) to generally assure that the facility is operating properly, and to perform a formal compliance test (e.g., measuring actual smokestack emissions).”

It is inappropriate for EPA to require the reporting of environmental performance on corporate maintained websites; it far exceeds any CAA authority to require records and violates the first amendment. Any requirement to alter the company's website would be a content base restriction subject to strict scrutiny. See, *Reed v. Town of Gilbert*, 135 S. Ct. 2218 (2015). And without conceding that this is commercial speech, this would not even meet the test for appropriate regulation of commercial speech. In *Central Hudson Gas & Elec. Corp v. Public Service Comm'n*, 447 U.S 557(1980), any regulation of commercial speech will be judged by whether it “directly advances the governmental interest asserted, and whether it is not more extensive than is necessary to serve that interest.” *Id.* at 566. Should EPA adopt this requirement it would fail both. This data is already being reporting to the agency as required under the existing rule, and the to one degree or another already provided to the public. To require reporting of the

same or similar data via company websites is both unnecessary does further advance the government interest, and is unequivocally more burdensome.²⁰ EPA should not pursue this requirement.

19.0 EPA SHOULD NOT FINALIZE RETROACTIVE REQUIREMENTS TO SUBPART OOOO

EPA proposed several new requirements for control devices and closed vent systems to Subpart OOOO that could only be viewed as new requirements to be applied retroactively to affected facilities initially constructed between August 23, 2011 and September 18, 2015. This is inappropriate as NSPS rule changes should only be prospective and not retrospective. Amongst the numerous changes, proposed paragraph §60.5370(d) encapsulates the problem best by stating: *You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of Subpart OOOOa of this part.* This suggests that new requirements in Subpart OOOOa for Subpart OOOO affected facilities will be applicable when subpart OOOOa is finalized. Examples of the specific problems cause by this retroactivity can be found in Sections 14.1 and 25.6.1 for detailed comments on this matter for bypass devices and storage vessels, respectively.

The D.C. Circuit has made it clear that regulatory agencies do not have authority to impose retroactive regulations unless that authority is expressly provided by Congress. *Georgetown University Hospital v. Bowen*, 821 F. 2d 750, 757 (D.C. Cir. 1987) (absent clear Congressional intent to the contrary, “legislative rules [should] be given future effect only.”). There is no indication in § 111 or the CAA as a whole that Congress granted EPA authority to impose retroactive requirements under an NSPS. Therefore, EPA should make it clear in this rule that all new requirements apply prospectively and only to newly affected sources. The only purpose for modifying any part in the existing Subpart OOOO should be to end date the rule and correct issues that do not add new regulatory burden since it is being replaced with Subpart OOOOa. EPA should remove all new compliance requirements being proposed in subpart OOOO and only finalize changes to paragraphs §60.5360 and §60.5365 which 1) end date the applicability of Subpart OOOO and 2) technical clarifications.

20.0 EPA SHOULD PROVIDE AN EXEMPTION FOR SOURCES ALREADY REGULATED BY AN ENFORCEABLE STATE PROGRAM

Numerous states have been proactive in developing regulatory programs to address emissions from the oil and natural gas operations. Clearly EPA is well aware of these programs, as Wyoming and Colorado programs are mentioned numerous times in the September 18, 2015 preamble for the proposed regulations. In fact, EPA relied heavily on aspects of the programs in these states in developing the proposed NSPS subpart OOOOa requirements. EPA also utilized technical information developed by the states to assist in the estimation of the impacts of the proposed federal rules.

The existing regulatory programs in Colorado and Wyoming, as well as other states, are in full force and are being successfully implementing and achieving reductions in VOC and methane emissions. As new

²⁰ Costs for building and maintaining such a website could easily reach \$15,000 or more annually per company, depending on the number of reports and site configuration.

oil and natural gas operations begin, they are subject to these regulations. And these regulations cover the same emission sources, typically with the same basic control requirements, as the proposed subpart OOOOa. If EPA moves forward with subpart OOOOa as proposed, the result will be that sources will be subject to overlapping and duplicative requirements. This situation will result in increased financial burden for the oil and gas industry without any environmental benefit.

In order to avoid this situation, API requests that EPA include provisions in the final subpart OOOOa that would clarify that sources that are subject to legally and practically enforceable requirements that address the same emission sources are not affected facilities under the rule. The precedent for this provision has already been established for this industry, as storage vessels can avoid being a subpart OOOO affected facility by having legally and practically enforceable requirements – see §60.5365(e).

For the fugitive emission standards for well sites and compressor stations, this request is discussed in detail in 27.2.2. However, API believes that it is warranted that such a provision also apply to well completions, compressors, and pneumatic pumps.

API recommends the following regulatory changes in §60.5365a.

§60.5365a

(a)(5) A well completion operation in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A centrifugal compressor in compliance with a legally and practically enforceable requirement that requires at least a 95% reduction in VOC or methane emissions is not an affected facility.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A reciprocating compressor in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas driven chemical/methanol pump or natural gas-driven diaphragm pump.

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site. A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

Note that there are additional revisions to §60.5365a(h)(1) and §60.5365a(h)(2) proposed in Section 24.4.1 and Section 24.4.5. See 24.4.5 for combined language.

Recommended regulatory changes for the fugitive program are provided in section 27.2.12.

Also, additional changes are recommended to various aspects of §60.5365a throughout this comment document. Specifically, see sections 22.2.2 and 22.2.3 for recommended changes for wells (completions), 24.3.3, 24.4.1, and 24.4.5 for pneumatic pumps, 25.1 and 25.2 for storage vessels, and 27.2.12.

21.0 SOCIAL COST OF METHANE

21.1 EPA's Use Of A Social Cost Of Methane Value Should Undergo Notice And Comment.

The benefits of the proposed rule are estimated using a social cost of methane (SC-CH₄), which has been derived from the approach the Interagency Working Group ("IWG") – a group of thirteen federal agencies developed for the Social Cost of Carbon (SCC). EPA's selected value for SC-CH₄ in this proposed rulemaking is arbitrarily taken from one scientific report that attempts to find an equivalent SC-CH₄ from the SCC, and for which EPA only requested a peer review, not formal public review and commenting. (80 Fed. Reg. at 56655) Moreover, even if the SC-CH₄ estimate development process was transparent, rigorous, and adequately peer-reviewed, the modeling conducted in this effort does not offer a reasonably acceptable range of accuracy for use in policymaking. In addition, the EPA has failed to disclose and quantify key uncertainties to inform decision makers and the public about the effects and uncertainties of alternative regulatory actions as required by OMB. For these and the reasons elaborated in this section, the SC-CH₄ should not be used to determine benefits as part of this rulemaking.

21.2 Assessment Of EPA's Overall Benefit-Cost Analysis

The EPA has prepared a Regulatory Impact Analysis (RIA) of the proposed Subpart OOOOa rules for reducing emissions at newly constructed, reconstructed, and modified oil and natural gas facilities. RIAs are required for rules that will have an annual impact in excess of \$100 million. Based on Executive Orders 12866 and 13563, the EPA is required to use the best available scientific and economic information available to quantify the benefits and costs of proposed rules.

EPA has estimated the benefits of the proposed rule using the SC-CH₄. Annualized engineering costs are estimated for each source based on capital costs, one-time labor costs, and on-going annual costs. EPA projected both the total costs and total benefits for the first year the full rule is in effect (2020) and for 2025 to demonstrate how affected sources accumulate over time. The net benefits in these years are the difference between the total benefits and costs, measured in 2012 dollars.

EPA's benefit-cost analysis as presented in the RIA shows that the overall benefits estimated to support the rulemaking are only marginally higher than the overall costs. For the selected regulatory option (Option 2), EPA estimates that the annual costs of the proposed rule will range from \$320 to \$420 million by 2025, and the annual benefits will be between \$460 and \$550 million (in 2012 dollars, using a three percent discount rate).

Reviewing the benefit-cost analysis more closely identifies aspects of the regulation where EPA is pursuing regulation despite their own analysis indicating that the costs outweigh the benefits for specific elements of the regulation. Within the RIA, the EPA does not provide annualized benefits for reducing fugitive emissions at both oil and natural gas well sites separately; rather, it reports only a single annual value for fugitive emissions from well sites. In 2025, the RIA estimates annual costs will be \$160 million and that annual benefits at a 3 percent discount rate will be \$150 million. Thus, as a group, fugitive emission controls for well sites do not pass the benefit cost test (meaning that costs are higher than benefits), even using the EPA's benefit and cost numbers.

21.3 Addressing Errors In EPA's Overall Benefit-Cost Analysis

A review of EPA's analysis of baseline emissions, emission reductions, and cost estimates is detailed in Attachment E. A number of issues were found with the EPA cost estimates, as well as the assumptions underlying the emission reduction estimates. Table 21-1 presents the benefit cost analysis estimates for 2025 from EPA compared to the estimates that correct some of the issues identified. The second set of columns shown in Table 21-1 show the estimated benefits and costs after correcting the key issues found, including:

- Oil well completions: EPA underestimated the cost of combustion controls for oil well completions. An adjustment was also made to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline. It was assumed that 25% of oil well completions are controlled in the baseline as a conservatively low estimate. Adjusting the estimated costs and the emission reduction estimate to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline, the costs are higher than benefits.
- Fugitives from well pads: EPA overestimated the emission reductions for fugitive emissions in their analysis. The model plant baseline emissions for both oil and natural gas well sites were estimated by rounding up the counts of major equipment at a well site and then multiplying by the component counts per major equipment. The resulting estimate was an overstatement of baseline emissions and corresponding emission reductions of 30-35 percent. EPA also excluded many cost elements in their estimates for semi-annual OGI leak screening and repair for well sites. Table 21-1 shows the impact of correcting the major flaws with the EPA cost estimates and correcting the estimated component counts for the model plants. These adjustments show that both oil and natural gas well sites fail the benefit cost test.
- Pneumatic Pumps: Several corrections were made to the estimates for pneumatic pumps that significantly change the net benefits estimate. These corrections include: a) adjusting the annual operating time for diaphragm pumps to 4 months of the year, on average; and b) correcting the costs of routing the pump vent to an existing control device, consistent with the estimate EPA used for wet seal compressor vents.

Based on the analyses, the total benefits in 2025 are around \$400 million (vs. EPA's \$460 million) and the costs are \$810 million (vs. EPA's \$310 million) for EPA's preferred regulatory approach (Option 2). Therefore, the overall proposed regulatory program results in a net benefit of around -\$410 million, and would not pass a benefit-cost test. Stated differently, the societal costs are significantly higher than the societal benefits from the methane reductions, even using the EPA's estimated SC-CH₄ of \$1,500/metric tonne in 2025, which as noted, is inappropriate for use in this analysis as stated below. Additionally, independent review by NERA found that the social net costs could be greater when specific factors ignored by EPA were included in the estimate of the social cost of methane.²¹ API used NERA's calculation of the social cost of methane and applied that to the revised emission reductions estimated by ERM and ERM's corrected cost estimates of the proposed regulation. This calculation showed that the net costs to society of the proposed regulation could exceed \$1 billion in 2025.

21.4 Precedence Issues Related To Prior Social Cost Of Carbon Publication.

The benefits of the proposed rule are estimated using the SC-CH₄, which has been derived from the approach the USG uses for estimating the SCC. Therefore, the SC-CH₄ inherits many of the same weaknesses as the SCC estimates.

The methodology used by EPA to estimate SC-CH₄ is similar to the EPA's approach to estimating SCC in the following ways:

²¹ NERA, "Technical Comments on the Social Cost of Methane as used in the Regulatory Impact Analysis of the Proposed Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector." December 2015.

- Uses the same three Integrated Assessment Models (IAMs).
- Uses the same five same socio-economic and emissions scenarios.
- Uses the same discount rates.
- Uses the same approach for averaging social costs across scenarios and IAMs.

As discussed in Section 4.3.1 of the RIA, EPA asked three peer-reviewers to provide an assessment of the SC-CH₄ approach and concluded that the reviewers generally agree that the SC-CH₄ estimates are “consistent” with the SCC estimates. Moreover, because Office of Management and Budget (OMB) guidance supports the use of SCC estimates, the EPA has concluded that using the SC-CH₄ estimates is an “analytical improvement” over their exclusion²².

²² P. 4-15 of RIA: “The fact that the reviewers agree that the SC-CH₄ estimates are generally consistent with the SC-CO₂ estimates that are recommended by OMB’s guidance on valuing CO₂ emissions reductions, leads the EPA to conclude that use of the SC-CH₄ estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis.”

Table 21-1 Comparison of 2025 Annual Benefits and Costs – Option 2, Low Impact, Discount Rate 3%.

Source	Emission Point	EPA Estimates from RIA				ERM's Estimates			
		Reduced CH4 Emissions (Mt)	CH4 Benefits (\$M)	Annualized Cost (\$M)	Net Benefits (\$M)	Reduced CH4 Emissions (Mt)	CH4 Benefits (\$M)	Annualized Cost (\$M)	Net Benefits (\$M)
Well Completions	Hydraulic Fracturing – Development	117,934	\$177	\$120	\$57	122,908	\$184	\$208	(\$24)
	Hydraulic Fracturing – Exploration	9,979	\$15	\$4	\$11	10,284	\$15	\$12	\$4
Fugitive Emissions	Well Pads	99,790	\$150	\$160	(\$10)	68,838	\$103	\$508	(\$405)
	<i>Oil Wells</i>	<i>33,980</i>	<i>\$51</i>	<i>\$119</i>	<i>(\$68)</i>	<i>21,685</i>	<i>\$33</i>	<i>\$338</i>	<i>(\$305)</i>
	<i>Natural Gas Wells</i>	<i>71,651</i>	<i>\$108</i>	<i>\$46</i>	<i>\$61</i>	<i>47,153</i>	<i>\$71</i>	<i>\$171</i>	<i>(\$100)</i>
	Gathering & Boosting Stations	29,937	\$45	\$17	\$28	Not Evaluated (used EPA's estimate)			
	Transmission Compressor Stations	9,072	\$14	\$3	\$11	Not Evaluated (used EPA's estimate)			
Pneumatic Pumps	Well Pads	29,030	\$44	\$5	\$38	11,186	\$17	\$57	(\$40)
Pneumatic Controllers	Transmission & Storage Stations	7,983	\$12	\$0.8	\$11	Not Evaluated (used EPA's estimate)			
Reciprocating Compressors	Transmission & Storage Stations	608	\$0.9	\$0.7	\$0.2	Not Evaluated (used EPA's estimate)			
Centrifugal Compressors	Transmission & Storage Stations	3,175	\$5	\$0	\$5	Not Evaluated (used EPA's estimate)			
Total		307,508	\$460	\$310	\$150	263,992	\$396	\$806	(\$410)

API believes that the use of the SC-CH₄ estimates is not warranted. Two primary reasons are as follows:

- The three peer reviewers' endorsement of the "consistency" of the SC-CH₄ estimates was in fact more modest than the EPA concludes. Further, the reviewers identified uncertainties with the approach being used. One reviewer commented that the fact that methane is not explicitly modeled in two out of the three IAMs used makes the approach inconsistent with SCC. A second reviewer commented that the emissions perturbation approach used for methane is inconsistent with the approach used for SCC and the impact of the difference is not understood. More importantly, the reviewer argued that neither the SCC approach nor the IAMs themselves have been peer-reviewed, which mean the SCC and SC-CH₄ estimates are likely not reliable.
- All of the problems with estimating the SCC have been inherited by the SC-CH₄ estimates. The issues associated with the SCC estimates include: differences in the climate outcomes of the three IAMs; significant differences in the damage functions between models; and issues with the averaging approach used to synthesize results. These challenges seriously affect the reliability and usefulness of the SCC and SC-CH₄ estimates in the foreseeable future.

The IAMs show significant differences in the climate outcome of the modeled results to the same increase in emissions. The three models project different temperature changes and sea level rise estimates resulting from the same increase in emissions and same underlying socioeconomic conditions. The temperature responses result from differences in the modeling of the carbon cycle, non-CO₂ radiative forcing, and sensitivity. Even in the short-term, through 2040, the IAMs can yield temperature changes that vary by a factor of two.

The damage functions linked to these temperature changes and sea level rise estimates are also very different, corresponding to a wide range of economic impacts. For example, one IAM shows gains in GDP through 2100 for some scenarios with increased emissions, while the other two IAMs show losses. The three models also show wide variation in the impact on the GDP of different countries and different types of economic costs (i.e. agriculture, heating and cooling). The differences in the structure of the models, which lead to significant differences in the damages estimates, are not well understood or explained.

The USG approach averages the SCC models across different socioeconomic scenarios to form a single estimate of the SCC for a particular discount rate. Inconsistencies in the models, and the fact that they may not be truly independent, may make such averaging inappropriate. Averaging assumes that each estimate is equally reliable and obscures the true uncertainty about the SCC that exists in the scientific literature. In addition, other key sources of uncertainty, such as economic variables, the damage functions, and temperature change can have significant impacts on social costs and are highly uncertain, Gillingham et. al. 2015. Modeling Uncertainty in Climate Change: A Multi-model Comparison. Cowles Foundation Working Paper. No. 2022. These issues need to be better understood before using SCC and SC-CH₄ in policy making.

One reviewers' assessment of the IAMs led him to conclude: "These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g., the discount rate) are arbitrary, but have huge effects on the SCC estimates the models produce; the models' descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation; and the models can tell us nothing about the most important driver of the SCC, the possibility of a catastrophic climate outcome.

IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading.”²³

21.5 Discount Rate Chosen Is Not Appropriate For This Rulemaking.

The selection of a 2.5% discount rate by EPA is not appropriate given the shorter atmospheric lifespan of methane. EPA justified the use of a 2.5% discount rate for the SCC by citing the long atmospheric lifespan of carbon dioxide which may remain in the atmosphere for several hundred years. However, methane dissipates significantly faster than carbon dioxide, typically lasting 80 to 100 years, eliminating the potential intergenerational equity impacts or uncertainty about future growth that the IWG used for justification in the SCC. As NERA detailed, changing the discount rate by just one half of a percent could lower the SC-CH₄ by as much as 37% in 2020.

21.6 EPA should identify and apply only the domestic impacts.

For the SC-CH₄, EPA does not report the net benefits to the United States; it only reports the global net benefits. Both estimates are relevant to the assessment of the value of the rule to U.S. taxpayers. However, using only the global benefits instead of domestic benefits is not consistent with past practice in benefit cost analyses, and is contrary to OMB Circular A-4. In EPA's prior analyses of the SCC, it estimates that between 17% and 23% of global SCC benefits actually accrue to the U.S. Using the PAGE and FUND models, NERA estimated that the using only the domestic damages would lower the SC-CH₄ by 76% to 92% in 2020, respectively.²⁴ Attachment E shows that the 2025 annual net benefits to the U.S. will range between \$-1.1 and -\$0.6 billion. By considering only the global benefits rather than domestic benefits, the EPA is suggesting that the benefits the U.S. can expect from the proposed rule are significantly larger than what may actually accrue to the U.S.

A complete review of EPA's analysis of baseline emissions conducted , emission reduction and cost estimates is detailed in Attachment E.

²³ Pindyck, Robert. 2013. "Climate Change Policy: What Do the Models Tell US". *Journal of Economic Literature* 2013, 51(3): 860-872.

²⁴ NERA 2015

TECHNICAL COMMENTS

22.0 OIL WELL COMPLETIONS

22.1 Applicability/Definitions

22.1.1 The Proposed Definition In §60.5430a For Low Pressure Well Is Inconsistent With The Amended Definition Of Low Pressure Well In 80 FR 48268, August 12, 2015 §60.5430.

EPA's proposed definition for low pressure well in §60.5430a is the following:

“Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.”

API supports the following amendment to this definition that was finalized by EPA in §60.5430 (80 FR 48268) on August 12, 2015 as the following:

Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the **true** vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

22.2 Exemptions From REC Requirements For Certain Hydraulically Fractured Oil Wells

22.2.1 EPA Is Correct When It States In The Preamble (FR 56633) That “Oil Wells Cannot Perform A REC If There Is Not Sufficient Well Pressure Or Gas Content During The Well Completion To Operate The Surface Equipment Required For A REC.”

In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of insufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for no tangible emission reduction since there is insufficient gas to operate the separator. Therefore, there are several instances where EPA should provide exemptions for the proposed REC requirements. Some of these exemptions may overlap since all involve the technical infeasibility of operating a gas/liquid separator in order to conduct a REC.

22.2.2 API Agrees With A Minimum GOR Of 300 Scf/Bbl As An Exemption Threshold In The Definition Of A Well Affected Facility Per § 60.5365a(A) But Recommends Language Be Amended For Consistency With The Greenhouse Gas Reporting Program.

API supports EPA's conclusion that hydraulically fractured oil wells with a gas-to-oil ratio (GOR) of less than 300 scf/bbl of oil produced should not be affected facilities subject to the well completion provisions of Subpart OOOOa. EPA's reasoning on FR 56633 for exempting low GOR oil wells is accurate. Operators in a given basin or field that are drilling and completing wells from specific formations generally have good knowledge and understanding of whether REC separator equipment can technically be operated on similar wells. There is also sufficient data on well GORs drilled in the same area and in the same formations.

API further recommends EPA amend the exemption language to be consistent with the Greenhouse Gas Reporting Program in such that the definition of the gas well affected facility in §60.5365a(a) be amended to the following:

Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per **stock tank** barrel of oil produced. The provisions of this paragraph do not affect the affected facility status of well.

22.2.3 Wells Requiring Artificial Lift In Order To Flow Back The Completions Fluids Should Be Exempt From The Well Completion Affected Facility.

EPA should exempt hydraulically fractured oil wells that require artificial lift in order to flow back the completions fluid. Many oil reservoirs have pressure that is insufficient for wells to naturally flow even after hydraulic fracturing. This can be evidenced by the prevalence of artificial lift equipment such as rod pumps visible across the landscape of many oil producing areas. In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of sufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for minimal emission reductions since there is insufficient gas available to operate the separator.

Examples of this are reservoirs in the Permian Basin where horizontal drilling is used to extend the life of existing producing formations. Many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flowback and there is insufficient gas to flare. One API Company estimates that approximately 30% of its hydraulically fractured horizontal wells and 80% of its hydraulically fractured vertical wells in the Permian Basin require artificial lift to flowback. Instead, following a hydraulic fracture, rod pumps are installed on the wells to artificially lift the fracture fluids either to fracture tanks or storage vessels. Other examples include reservoirs in the north central East Texas basin which produce heavy black oil, also called “dead oil” because there is no associated gas produced with the oil. In this area, gas to operate separation must be purchased as it is not available from well production.

API recommends the suggested revision to the definition of well affected facility:

§60.5365a(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per **stock tank** barrel of oil produced. **Wells that must use artificial lift equipment to flowback completion fluid are not well affected facilities.**

API also recommends the addition of the following definition for Artificial Lift Equipment in §60.5430a:

Artificial Lift Equipment means the use of mechanical pumps (e.g., rod pumps or electric submersible pumps) to flowback fluids from a well.

22.2.4 EPA Should Exempt Inert Gas Venting During Separation Flowback Stage

The language in §60.5375a(a)(3) and §60.5375a(f)(2) implies all gas must be recovered to a completion combustion device if it cannot be routed to pipe “except 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 waterway when wells are in the separation flowback stage. Nitrogen foam may be used to complete a well, as is done for oil wells in the San Juan Basin in northwest New Mexico. In this situation, the operation of a separator may be feasible, but the initial gas quality “is not of salable quality” nor can the produced gas be combusted due to the high nitrogen (N₂) content. N₂ is an inert gas, and therefore it is technically infeasible to combust the gas. The proposed language is required to clarify that in this specific situation, where gas cannot go to pipe for one of the acceptable reasons provided by EPA and also cannot be combusted due to technical infeasibility, the gas can be vented during the separation flowback stage. Note that in addition to N₂, the content of other inert gases such as CO₂ or hydrogen sulfide (H₂S) may also disallow the use of a combustion device due to high inert gas composition.

In addition, EPA apparently intended to allow venting of the noncombustible flowback gas but neglected to include it in the rule text language.

“... [EPA] are proposing an operational standard for subcategory 1 wells that would require a combination of gas capture and recovery and completion combustion devices ..., with provisions for venting in lieu of combustion for ... or for periods when the flowback gas is noncombustible.” 80 FR 56630.

“...[EPA] are proposing an operational standard for subcategory 2 well completions ... with provisions for venting in lieu of combustion for ... or for periods when the flowback gas is noncombustible.” 80 FR 56632.

Therefore, API recommends the following clarifications be added to the rule:

§60.5375a(a)(3) You must capture and direct recovered gas to a completion combustion device, except 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 **or it is technically infeasible due to inert gas concentration.**

§60.5375a(f)(2) You must capture and direct recovered gas to a completion combustion device, except 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 **or it is technically infeasible due to inert gas concentration.**

22.2.5 EPA Should Clarify That A Separator Is Not Required To Be Onsite During The Initial Flowback Stage When It Is Technically Infeasible To Operate.

Certain wells produce flowback with stable entrained gas, foam, emulsion, or infrequent slugging gas flow. Gas from hydraulically fractured oil well flowback often initially starts appearing in slugs before the flow begins to stabilize. Infrequent slugs of gas may drive liquids and/or foams into the gas lines unless a prohibitively large gas space above the liquid/foam is maintained in the separator (see section 12.1). These conditions do not supply a sufficiently steady stream of gas to operate a separator such that flowback from these wells never leave the initial flowback stage prior to production. In these situations, it is unclear if operators are required to rent separation equipment to have onsite even knowing the equipment would never be utilized due to well characteristics and engineering constraint. API believes it was EPA's intent to not require separation equipment to be onsite during the initial flowback stage based on the definitions proposed in §60.5430a and the requirements in §60.5375a(a)(1)(i) and §60.5375a(a)(1)(ii). This would result in extraneous compliance costs for minimal emission reduction since there is insufficient gas to operate the separation equipment. Therefore, API requests EPA clarify that well completion operations that remain in the initial flowback stage through the start of production are not required to have a separator onsite or exempt wells where field experience indicates that flowback fluid characteristics demonstrate that a sufficient and steady amount of gas is not available to operate a separator. In instances where flowback fluid deviates from expected offset well performance such that

separation of gas is practical, the operator should stop flowback (in initial flowback stage) and restart the well completion operation in separation flowback stage after separation equipment is installed.

API recommends the following clarification be added to §60.5375a(a)(1)(i):

- (i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section. **A separator is not required to be located onsite during the initial flowback stage. Once conditions allow for separation, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in the separation flowback stage.**

22.2.6 API Agrees That The Lack Of A Flow Line/Gathering System Meets The Criteria Of Technical Infeasibility In 60.5375a(1)(ii).

EPA states in the preamble on page 56631:

“There may be cases in which, for reason(s) not within an operator’s control, the well is completed and flowback occurs without a suitable flow line available. We are aware that this situation may be more common for wells that are primarily drilled to produce oil. In those instances, § 60.5375(a)(3) requires the combustion of the gas unless combustion poses an unsafe condition as described above.”

Before natural gas production can be sent to natural gas gathering line, all of following must be done:

A natural gas gathering line/system must be permitted, installed and operational in the area.

Permits are required for right-of-way, installation, compressor site air quality, etc. for the natural gas gathering line/system before it is installed, which take much longer than getting a permit to drill a well. Designing and installing a natural gas gathering system (including pipelines, compression, gas plant to send the gas to, etc) takes considerable time and money. Furthermore, designing and installing a gas gathering line depends on having enough natural gas production to justify the exceptional cost and burden for the gas gathering system.

A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line. In most cases the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added.

Necessary permits and right of way must be obtained for the pipeline from the well site to the natural gas gathering system. Permits and right-of-way are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary right-of-way can be difficult and may require a court order.

The natural gas must meet the specifications of the natural gas gathering line. Contracts with the gathering company include specifications for entering the gas gathering line including concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. Carbon dioxide and nitrogen are often used to energize well stimulations to assist with flowback and cleanup. The carbon dioxide and nitrogen flowback and cannot be routed to the pipeline because they make the gas not salable. The natural gas gathering system operator ultimately controls when an operator can send gas to sales.

There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well and not choke it. When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure and maintain adequate velocity to clean-up the well and reservoir. Any time this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline. This allows clean-up of the well bore and is critical to minimize the potential for formation damage. It is possible that sensitive zones can lose productivity due to increased clean-up time required if back pressure is added to the well because of the line pressures. Once a fracture stimulation is pumped, flowback and cleanup must proceed regardless of sufficient pressure to enable sales or severe and permanent reservoir damage is likely. Adding compression to overcome line pressure on low energy wells has been tried several times and found to be not feasible for technical reasons. Furthermore it adds additional emissions for engines to power the compressors while greatly increasing the cost.

The natural gas gathering line must be operational at the time of the completion. Natural gas gathering lines can be down for a multitude of reasons including but not limited to compressor maintenance or repair, line maintenance, line inspection, the gas plant being shut down, etc.

A gas gathering system with sufficient capacity must be in place. Gas that is produced from an oil well but can't be sold is known as "stranded" gas. It's stranded because the pipeline infrastructure needed to gather and transport the gas for processing is not available. Unlike gas fields where infrastructure may be unavailable in limited situations such as exploration, delineation, or some leasehold wells, gas gathering infrastructure can be unavailable for oil wells across an entire field or area. Lack of available infrastructure occurs for various reasons. For instance, insufficient associated gas production volumes may make it uneconomic to gather, process, and sell the produced gas. Or, economic gas gathering infrastructure construction may lag behind the start of new well production, as currently occurs in the Bakken oil shale formation of the Williston Basin in North Dakota. During flowback and continuing into production, stranded gas from high pressure wells such as those in the Bakken is flared for both reasons of safety and VOC emissions reduction.

While it's imperative that a gas gathering system must be available for a REC, the gathering system must also have the capacity to collect the volume of gas produced during a REC at a flow rate sufficient to clean out the well. Gas gathering systems are designed to accommodate the maximum anticipated flow rate and pressures during the production phase of wells, not necessarily the flowback phase. While this could also be a potential issue for certain gas wells, it's a known issue in the Bakken oil shale where limited gas gathering infrastructure exists. Flowing wellhead pressures are high (e.g., 4000 psi), and gas volume during initial flowback can spike at a rate many times higher than the flow rate when the well is turned over to production.

Where gathering systems exist, sending all the initial gas volume from flowback through the gathering line without properly choking the flow to prevent exceeding the gathering line capacity may cause an upset somewhere downstream because of over pressuring the system. Any major upset has the potential to result in a serious safety and/or environmental incident. Choking the flowback to meet gas gathering capacity can cause poor flowback velocity which inhibits proper cleanout of the well. Consequently, a partial REC might be feasible as some of the flowback gas may be able to be sent to sales, but remaining gas would need to be flared so as to not overpressure or exceed the capacity of the gathering system.

Furthermore, there are many reasons to complete a well and flowback without a natural gas gathering line or production equipment in place including but not limited to:

- **Avoiding lease jeopardy by establishing production in paying quantities.** Mineral leases contain expiration clauses tied to specific milestones to encourage the development of a lease hold in a timely fashion. One of the typical milestones is performance of a well completion. If the date is missed, the lease expires, causing the rights owner not only to lose the cost of the lease, but the investment in assessing the lease and preparing to drill

it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to unavailability of REC equipment create an additional risk that the operator could fail to live up to steps in the contract and negate the contract causing the operator to lose their rights to the minerals.

- **Not knowing the composition of gas in advance limits the ability to design the production equipment or pipeline.** In some areas, the production equipment and pipeline are not installed until the composition of the gas is known in order to design the equipment to handle the gas and condensate, particularly for sour gas fields where the level of H₂S is critical for the design requirements. This is particularly significant in areas where the reservoir and properties are not well known and delineated.
- **The surface rights must be obtained for installing production equipment.** In many cases the owners of the mineral rights are different from the surface rights; therefore, surface rights must be obtained for construction of a pad to drill a well and subsequently install the production equipment. These surface rights are size/area limited and in many cases not sufficient to have in place both the completions equipment and the production equipment at the same time so companies wait to install the production equipment until after the drilling and completions equipment are gone. This also limits the “footprint” of surface disturbance to the area.

22.3 Distance To The Gathering Line Is Not A Valid Criterion On Which To Base Requirements For Gas Recovery.

Sufficient natural gas production in the area is required to justify the cost and burden for permitting, designing, and building the natural gas gathering system. Before gas can be routed to a gas gathering line, all the following must be done:

- A natural gas gathering line system must be permitted, installed and operational in the area a reasonable distance from the well.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must be in place.
- The necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system must be obtained.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well against the pipeline pressure without lowering the flow and velocity to the point where the well will not adequately clean-up.

Furthermore in the preamble EPA has solicited comment on criteria that could help clarify availability of gathering lines (FR 56634), and specifically mentions *“that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.”*

EPA may have misinterpreted the cited Montana regulation: “(2) The owner or operator of an oil and natural gas well facility shall operate the air pollution control equipment and comply with the air pollution control practices required in (1) from the initial well completion date for the facility until the department decision on the permit application is final. (Emphasis added)

Therefore, this control equipment requirement applies from the “initial well completion date for the facility” until a decision is made on a permit application. The term “initial well completion date for the facility” is not defined in the section referenced by EPA. However, if you look at the history of this regulation (prior regulation 75-2-211), the term means:

“For purposes of this section, the initial well completion date for an oil or gas well facility is:

- (i) For an oil or gas well facility producing oil, the date when the first oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after casing has been run: and
- (ii) For an oil or gas well facility producing gas, the date when the oil or gas well facility is capable of producing gas through wellhead equipment from the ultimate producing interval after casing has been run.

Therefore, the Montana regulation appears to only apply from the date a well is producing oil and natural gas to lease sales (what EPA describes as the production phase) and not during flowback from hydraulically fractured completions.

In addition to the issues with gathering line permitting and availability outlined in detail above, there are many situations that would disallow legal access to a gathering system even if an existing gas pipeline was less than one half mile from a well including but not limited if the land between the well and pipeline is designated wetland, the presence of endangered species has been identified, landowner disputes, and archeological issues.

22.4 Impacts, Emissions, Costs

Most of the cost to flare flowback gases is for rental of the separator equipment, mileage, labor to install and remove equipment, and additional personnel to operate the specialty equipment. In public comments on the EPA White Paper on Hydraulically Fractured Oil Wells, IPANM members estimated the cost for flaring oil well completions as up to \$10,000 per day. API agrees that this is a more reasonable typical cost to rent, transport, install, operate and remove separator and flare equipment. In addition, flowback can range from one day to more than 30 days, with 3 to 7 days being most typical.

22.5 REC Equipment Availability

API has not had enough time to determine if there is adequate REC equipment available to handle the new requirements on hydraulically fractured oil wells. However, in the current low oil price environment, many operators are drilling oil wells, but delaying well completions until a later date. API estimates that by the time Subpart OOOOa is finalized, there could be a backlog of up to 10,000 drilled oil wells waiting to be completed that could overwhelm the REC equipment market during an oil price recovery.²⁵ Therefore, API recommends that hydraulically fractured oil wells that have been drilled, but not completed by the effective date of the final rule, should be exempt from the requirements to conduct an REC. In reality, companies will likely conduct an REC if equipment is available and if feasible, but this exemption would allow the requirement for REC for hydraulically fractured oil wells to begin without a very large backlog of drilled wells that have not yet been completed. Otherwise, there could be many instances where a company is not able to find REC equipment and would be out of compliance. This will

²⁵ Doan, Lynn and Dan Murtaugh. (2015, April 23 U.S. Shale Fracklog Triples as Drillers Keep Oil from Market. *Bloomberg Business*. Retrieved from < <http://www.bloomberg.com/news/articles/2015-04-23/u-s-shale-fracklog-triples-as-drillers-keep-oil-out-of-market-i8u004xl>>

give REC equipment manufacturers and the oil and natural gas industry more certainty in understanding additional REC equipment needs in the future.

22.6 Reporting and Recordkeeping

22.6.1 EPA Should Not Require Tracking Attempts To Connect To A Separator For Flowback That Never Leaves The Initial Flowback Stage.

As described in Section 22.2.6, API requests that EPA clarify the recordkeeping requirements outlined in §60.5420a(c)(1)(iii)(A) for tracking attempts to connect to a separator as only being applicable during the separation flowback stage (after initial flowback, they are hooked up to a production system). For well completion operations that remain in the initial flowback stage, a separator is not required and, therefore tracking attempts to connect to one is not applicable.

23.0 RECIPROCATING COMPRESSORS

23.1 Emission Limits/Control Requirements

23.1.1 Negative Pressure Requirement On Routing Reciprocating Rod Packing Emissions Back To Process Is Flawed And Should Be Amended Relative To Operating Pressure – Not Relative To Atmosphere.

The requirements in §60.5385(a)(3) and §60.5385a(a)(3) that require the collection of emissions from the rod packing under negative pressure is technically flawed where EPA states the following:

“Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system...”

Operating a crankcase collection system under a negative pressure (vacuum) leads to significant safety issues with the possibility of oxygen being introduced into the system.

Therefore, API recommends the language be amended in in §60.5385(a)(3) and §60.5385a(a)(3) to the following:

“Collect the emissions from the rod packing using a rod packing emissions collection system ~~which operates under negative pressure~~ and route the rod packing emissions to a process through a closed vent system...”

24.0 PNEUMATIC PUMPS

24.1 General Discussion

API appreciates EPA's efforts to simplify control requirements for pneumatic pumps as well as EPA's recognition that there are limited scenarios for which control of pneumatic pumps will be cost effective. However, from review of the preamble of the rule proposal and the Technical Support Document, it is clear that EPA did not appreciate some key technical issues as well as some key costs that would be incurred if the rule were finalized as proposed.

Each of these points is expanded upon in this section, but API recommends that the following exemptions should be added to the proposed requirements for pneumatic pumps:

- Technical Feasibility – If it is not technically feasible to connect a pump to an existing on site control device, there should be an exemption under the rule.
- Small or limited use emission pumps (< 53 thousand scf per year emission rate, which is equivalent to a continuous 6 SCFH emission rate) rate or any pump operating less than 90 days per year).

Additionally, EPA has proposed overly burdensome and costly testing and monitoring requirements for control systems used to control pumps. If control requirements are retained for any types of pneumatic pumps, the rule should eliminate testing, monitoring, and recordkeeping requirements for the control device that are triggered solely due to the connection of a pneumatic pump exhaust to the closed vent system or control device. Alternatively, EPA should only require control of pumps when an existing Subpart OOOO/OOOOa control device which is already subject to the same requirements as in the proposed rule is present.

Finally, for many technical reasons, API believes it is important that EPA should clarify in the rule that the presence of a heater or boiler should not be considered to be equivalent to presence of control device. This is discussed in detail in Section 13.0 of these comments.

API also appreciates EPA's preamble discussion that recognizes the limitations of solar powered pumps, the typical unavailability of electricity at well sites and other remote sites, and the fact that gas-assist lean-glycol recirculation pumps on glycol dehydration units are not pneumatic pumps. API agrees with EPA's approach of defining the affected source as only pumps using natural gas as the pneumatic power source and located at a site with an existing control device. API also agrees with EPA's approach of only requiring control of new, modified or reconstructed pneumatic pumps on sites with existing control devices (combustion control or vapor recovery). However, API has several important issues with the details of the regulation as proposed.

- EPA inappropriately requires an existing control device/system to meet the closed-vent-system, performance testing, monitoring, and recordkeeping requirements of Subpart OOOOa if a new, modified, or reconstructed pneumatic pump is routed to it. This is exacerbated by the proposal to require the same measures as for wet-seal centrifugal compressor affected source control devices.
- API believes the capital cost estimate EPA made is low and that several significant cost items are left out of the cost analysis.
- API believes the estimated emissions per pump for diaphragm type pumps is overestimated and the equal proportional split between piston type chemical pumps and diaphragm pumps is incorrect. Due to the limited time available for comment, API did not have time survey members adequately, but there are many more piston pumps installed than diaphragm pumps.
- Because the cost is underestimated and the emissions overestimated, the control actions required by the regulation are not cost effective in many instances.
- EPA failed to recognize important design and process factors that could render routing a pneumatic pump to an existing control device technically infeasible or unsafe.
- Some details of the regulatory language are unclear or not defined fully.

Each of these issues is discussed in more detail in the following sections.

24.2 Control Device And Closed Vent System Requirements

As written, control devices not subject to Subpart OOOO or OOOOa would be required to be used to control emissions from pneumatic pumps. It is not clear if this was EPA's intent in writing the rule. From the lack of consideration for performance requirements, performance testing, closed vent system monitoring, recordkeeping, and reporting compliance costs in the economic analysis, it appears that EPA did not intend for control devices not subject to Subpart OOOO or OOOOa to be pulled into the monitoring, reporting, and recordkeeping requirements under Subpart OOOOa. If EPA maintains a requirement to route higher emitting pneumatic pumps to existing control devices, this should not trigger the performance specifications, performance testing, monitoring, closed vent system monitoring, recordkeeping, and reporting requirements for the control device if it is not already subject to regulation under Subpart OOOO. This change from the proposed approach would address one of the two critical cost elements ignored by EPA when assessing the cost of control; specifically, the costs of testing, monitoring, reporting, and recordkeeping requirements.

EPA should also provide for routing of pump exhaust from glycol heat medium pumps (typically diaphragm type pumps) to a controlled tank or knock-out drum prior to the control device to provide for buffering the intermittent flow when the pump exhaust stroke occurs. This would provide for more stable flow to the control device and piping system and simplify connecting a pneumatic pump exhaust to an existing control system.

The proposed rule unnecessarily and inappropriately requires existing control devices and closed vent systems to comply with the full suite of requirements identical to those specified for control devices and systems on centrifugal compressor affected facilities degassing tank vents if a new, modified, or reconstructed pneumatic pump affected source is routed to the control device. EPA failed to recognize that the majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. Since centrifugal compressors are rarely used in the production segment and new, modified, or reconstructed centrifugal compressors in the gathering & collection, processing, and transportation & storage segments are almost certainly dry seal equipped, the probability is near zero that an existing control device on well sites or remote facilities would already be subject to the centrifugal compressor affected source requirements for closed vent systems and control devices. Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. Even where an existing control device and closed vent system has applicable requirements under Subpart OOOO, these are almost certainly those requirements for control devices and closed vent systems installed on storage tank affected sources rather than centrifugal compressor affected sources and thus would have new requirements under the proposed rule. This could subject an individual control device and closed vent system to a dual set of requirements if the proposed rule is finalized as proposed. Note that this discussion focuses on enclosed combustion control devices as sites with VRU's are likely to have electricity and hence no pneumatic pump affected sources.

By requiring existing closed vent systems and control devices to comply with the specified requirements listed in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a the proposed rule retroactively applies unnecessary, burdensome, and costly requirements to existing control devices and systems that were not designed, installed, or intended to comply with these requirements. Note also that none of the additional costs are included in EPA's analysis of the reasonableness of controlling pneumatic pump affected sources and the additional costs are likely to render such control not reasonable - cost analysis details are presented in a separate section of these comments.

- §60.5411a & §60.5416a: An existing closed vent system may not be designed or constructed to meet the standard of "no detectable emissions" specified in §60.5411a

and detailed in §60.5416a. Again, this may force retrofit or replacement of the existing piping system to enable meeting the “no detectable emissions” requirement.

- §60.513a: Existing control devices and the piping to them are not likely to have the necessary ports installed to enable performance testing as specified in 60.5413a and would have to be taken offline in order to retrofit them if retrofit is even possible.
- §60.5415 & §60.5417: Existing control devices are unlikely to have all of the monitoring instruments and capabilities required for continuous compliance demonstration as required in §60.5415a and these would have to be retrofitted to the control device. Again, retrofit may not be possible which would leave an operator with no avenue to comply without installing a new control device which EPA already found to be not reasonable from a control cost standpoint. Additionally, the data monitoring, logging and averaging required under §60.5417a would require either installation of an entirely new monitoring system or tying the monitoring devices into an existing automation system programmable logic controller (PLC) which may not have the number of input ports necessary nor have the memory and computing power necessary. Due to the typical lack of electrical power, the installation of a monitoring system would also require installation of a solar power system with the necessary power to operate the system and the necessary battery back-up to assure adequate data recovery.

Requiring control devices and covered vent systems, where a pneumatic pump affected source is routed to them, to comply with the performance testing, continuous monitoring, and associated requirements of the proposed rule is not necessary. The exhaust from a pneumatic pump affected source is the same natural gas used for the pilot flame in a combustion control device and as fuel for a boiler or heater. It is not difficult to combust and should not require the same rigor of demonstration for more difficult to combust compounds. In general, the low molecular weight straight chain aliphatic hydrocarbons that characterize the natural gas industry, including associated gas, are easy to combust.

To address the issues regarding retroactive application of the requirements in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a to existing control devices and closed vent systems not already subject to the requirements proposed, API recommends EPA take one of the following approaches.

Maintain the current definition of pneumatic pump affected source and require that the existing control device and closed vent system comply with whatever existing requirements for testing, monitoring, and reporting exist for the particular site/control device and closed vent system.

-or-Redefine the pneumatic pump affected source as only those new, modified, or reconstructed natural gas powered pneumatic pumps installed at a site with an existing control device that is already subject to the requirements contained in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a proposed in the rule.

To assure the integrity of the newly installed piping routing a new, modified, or reconstructed pneumatic pump affected source to an existing closed vent system or directly to the control device EPA could require an annual leak inspection with an Optical Gas Imaging camera for the newly installed piping to an existing control device or closed vent system.

24.3 Impacts, Emissions, Costs

24.3.1 EPA Underestimated The Cost Of The Proposed Control Strategy Which Renders It Not Cost Effective In Many Situations.

In the cost analysis for the proposed control strategy for pneumatic pumps, EPA incorrectly only listed a one-time capital cost impact of \$2,000 for the design and installation of piping to route vapors from the exhaust of a pneumatic pump to an existing control device. This value was based upon Natural Gas Star program data.²⁶ Using a 7% interest rate, EPA estimated the annualized cost of controlling a pneumatic pump at \$285/year.

This value is too low and does not include significant cost items required by the rule. As an example, EPA assumed a cost of \$23,252 for tying a wet-seal centrifugal compressor seal-oil degassing tank into an existing control device. The low pressure nature of both pneumatic pump exhaust and a seal-oil degassing tank are similar. Unfortunately, the Technical Support Document for Subpart OOOOa (TSD) discussion of pneumatic pump control and seal-oil degassing control is not detailed enough to understand the difference in EPA's cost estimates.

API believes the average capital cost (inclusive of engineering) that would be incurred for design evaluation, designing, and construction of the piping to tie a pneumatic pump into an existing control device/system would be closer to \$5,800 and would vary considerably from site to site

Following are the details of API's initial capital cost estimate.

- Collecting the site specific information on an existing control device/system and performing an engineering evaluation of the ability to safely and technically add pump exhaust gas to the control device/system. Eight (8) hours of engineering time at \$185 per hour = \$1480.
- Evaluating the specific pump's ability to tolerate the exhaust backpressure necessary to route to the existing control device/system; designing the piping necessary to route a pump exhaust to the control device/system; specifying materials, connection points, and connection types for routing a pump exhaust to the control device/system; and writing a work-order and procedure for connecting. 8 hours of engineering time at \$185 per hour = \$1480.
- Ordering and collecting materials for installing the piping, commissioning a contractor to perform the work, and overseeing the work. Six (6) hours of construction specialist time at \$140 per hour = \$840.
- Travel to the site, installation of the piping for tie-in, verification of the proper functioning of the tie-in and travel from the site. One day of a contract construction crew time at \$2,000 per day = \$2,000.
- Utilizing EPA's assumed 7% interest rate, this equates to an annualized initial capital cost of \$826 rather than EPA's value of \$285.

In addition to underestimating the capital costs of routing the emissions to a control device, EPA did not consider other significant initial and reoccurring costs that would be incurred. The proposed rule requires an existing control device and closed vent system with a pneumatic pump routed to them to comply with the same performance testing, closed vent system, continuous monitoring, and recordkeeping and

²⁶ <http://www.epa.gov/gasstar/documents/pipeglycoldehydratorovru.pdf>

reporting requirements applicable to closed vent systems and control devices specified for centrifugal compressor affected facilities. The majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO or Subpart OOOOa requirements let alone those for centrifugal compressor affected facilities. The probability is near zero that an existing control device subject to the centrifugal compressor affected source requirements for closed vent systems and control devices will be on a site where a pneumatic pump source is located.

Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or Subpart OOOOa be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO or Subpart OOOOa. As such, costs not included in EPA's analysis are:

- The costs for an initial M21 demonstration that the closed vent system, at a site not already subject to the requirements under Subpart OOOO, is operating with no detectable emissions.
- The costs for initial and periodic performance testing of a control device that is not already subject to the required performance testing.
- The costs for monthly smoke inspections, including travel to and from the site for a trained visual smoke inspector.
- The costs for design, installation and maintenance of a parametric monitoring system.
- The recordkeeping and reporting cost.

The table below provides a more complete estimate of the costs associated with implementing the proposed rule requirements for pneumatic pumps. This table reflects the true cost of compliance with the rule, including potential source testing, the need to install monitoring equipment, and the costs of conducting recurring inspection and equipment maintenance that would all be triggered by the proposed compliance requirements. Note that none of the performance testing exemptions listed in §60.5413a (a) 1 - 7 are considered. It should be noted that:

- Heaters with a design capacity of 44 MW (150 million BTU/hr) will not occur in the types of sites where pneumatic pump affected sources will be used
- Heaters used at well sites and other remote sites are likely to be seasonally used, or have intermittent firing dependent on heat demand and hence will not be able to accept the exhaust gas from a pneumatic pump as part or all of the fuel at all times
- As discussed previously, an existing control device is almost certainly not already subject to the performance testing requirements of §60.5413 and hence not manufacture certified.
- Hazardous waste incinerators or hazardous waste fueled heaters will not occur at the type of sites where pneumatic pump affected sources will be used.

Table 24-1 Pneumatic Pump Control Cost Table

<i>Cost Item</i>	<i>Initial Cost</i>	<i>Annualized Cost</i>
Capital Costs (including engineering)	\$5,800	\$826
Option 1 Combustor Testing (repeat each 5 years)	\$6,000	\$1,200
Option 2 Process Heater Testing (repeat each 5 years)	\$6,000	\$1,200
Annual M21 & Visual CVS Inspection (Contractor or Trained Technician - 1/2 day with vehicle)	\$600	\$600
Monthly 15 min Smoke Check (trained operator inspection - \$160/month)		\$1,800
Flow Monitor, Thermal Dispersion Meter	\$5,000	\$712
CPMS - install measurement device and solar panel	\$9,000	\$1,282
CPMS - Annual Maintenance (contractor 1/2 day)		\$600
Annual CPMS Auditing (trained instrument technician complete with equipment and vehicle - 1/2 day)		\$600
<i>Scenario</i>	<i>Annualized Total</i>	
Sites with Affected Pneumatic Pumps & Combustor field performance test	\$6,908	
Sites with Manufacturer Certified Combustor (no performance test)	\$6,420	
Sites with Affected Pneumatic Pumps (& Process Heater performance test)	\$6,908	
Sites with existing Subpart OOOO or OOOOa affected storage tank with control device	\$3,308	
Sites with existing Subpart OOOO or OOOOa affected compressor with control device	\$826	

Table 24-2 Retrofit Costs for Control Devices

<i>Cost Item</i>	<i>Initial Cost</i>	<i>Annualized Cost</i>
Retrofit control device with new or relocated ports to enable performance testing per 60.5413a. (likely to occur)	\$3,000	\$427
Retrofit closed vent system to meet "no detectable emission" requirement per §60.5416a (less likely to occur)	\$3,000	\$427

Table 24-3 Average Pneumatic Pump Emission Rate (Reproduced from TSD)

	Tons/year Methane	Tons/year VOC
Piston Pump	0.38	0.11
Diaphragm Pump	3.46	0.96

Combining the complete estimate of actual costs for routing a pneumatic pump affected source to an existing control device with the emission estimates for piston pumps and diaphragm pumps from the Technical Support Document (repeated in proposed rule preamble) yields the following tables of control cost per ton for methane, VOC, and from a multipollutant approach consistent with that used by EPA for the proposed rule.

Table 24-4 Piston Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	Scenario	Single Pollutant Approach		Multipollutant Approach	
		Methane Only	VOC Only	Methane	VOC
Production Piston Pumps	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$18,178	\$62,797	\$9,089	\$31,399
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$16,894	\$58,362	\$8,447	\$29,181
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$18,178	\$62,797	\$9,089	\$31,399
	<i>Sites with existing Subpart OOOO or OOOOa affected storage tank with control device</i>	\$8,705	\$30,070	\$4,352	\$15,035
	<i>Sites with existing Subpart OOOO or OOOOa affected compressor with control device</i>	\$2,174	\$7,509	\$1,087	\$3,755

¹Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2. Inclusion of these costs would only further increase the cost effectiveness ratios. It also does not include the cost of recordkeeping and reporting required by the rule.

Table 24-5 Diaphragm Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	<i>Scenario</i>	Single Pollutant Approach		Multipollutant Approach	
		Methane Only	VOC Only	Methane	VOC
Production Diaphragm Pump	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$1,996	\$7,196	\$998	\$3,598
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$1,855	\$6,687	\$928	\$3,344
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$1,996	\$7,196	\$998	\$3,598
	<i>Sites with existing Subpart OOOO or OOOOa affected storage tank with control device</i>	\$956	\$3,446	\$478	\$1,723
	<i>Sites with existing Subpart OOOO or OOOOa affected compressor with control device</i>	\$239	\$860	\$119	\$430

¹ Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2. Inclusion of these costs would only further increase the cost effectiveness ratios. It also does not include the cost of recordkeeping and reporting required by the rule.

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard cost effectiveness, the proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: “In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of \$5,700 per ton.**” While EPA does not make an affirmation that is as clear-cut for methane, EPA’s decisions establish a precedent. For quarterly OGI monitoring for well sites, EPA estimated the cost effectiveness levels shown in Table 24-6. For this option, EPA determined that “we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach.” (80 FR 53363). Therefore, since EPA rejected this alternative with a cost effectiveness of \$1,761 per ton of methane reduced, this clearly establishes that EPA believes that \$1,761/ton of methane is unreasonable.

Table 24-6 EPA’s Estimated Cost Effectiveness with Savings (\$/ton) for Quarterly OGI Monitoring at Well Sites.

Single Pollutant ^a		Multipollutant ^b	
Methane	VOC	Methane	VOC
\$3,521	\$12,668	\$1,761	\$6,334

^aTable 5-16 of the Background Technical Support Document.

^bTable 5-17 of the Background Technical Support Document.

As illustrated above in Table 24-4, for piston pumps, the control costs for the only likely scenarios of an existing control device and closed vent system having no performance testing or monitoring requirements under Subpart OOOO or an existing control device and closed vent system being subject to only the Storage Tank performance testing and monitoring requirements under Subpart OOOO exceed the reasonable cost of control per ton whether viewed from a single pollutant standpoint or from a multipollutant standpoint. The only reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the proposed rule and this was only cost effective under the multi-pollutant approach. As explained in more detail earlier in these comments, the probability of this occurring is near zero.

For diaphragm pumps, the cost effectiveness values shown above are lower due to the higher emissions. However, as discussed further in 0, diaphragm pumps are generally used for heat tracing and as such are not used everywhere and, when they are used do not operate year round. Using a more realistic estimate of 4 months of operation per year, the emissions from these pumps are actually 1/3rd the level assumed by EPA. The table below reflects the cost effectiveness of controlling diaphragm pumps after accounting for their non-year round operation.

Table 24-7 Diaphragm Pump Control Cost Effectiveness (assuming 4 months of annual pump operation)

		Single Pollutant Approach		Multipollutant Approach	
		Methane Only	VOC Only	Methane	VOC
Production Diaphragm Pump	<i>Scenario</i>				
	<i>Sites with Affected Pneumatic Pumps & Combustor field performance test¹</i>	\$5,989	\$21,587	\$2,995	\$10,793
	<i>Sites with Manufacturer Certified Combustor (no performance test)</i>	\$5,566	\$20,062	\$2,783	\$10,031
	<i>Sites with Affected Pneumatic Pumps (& Process Heater performance test)¹</i>	\$5,989	\$21,587	\$2,995	\$10,793
	<i>Sites with existing Subpart OOOO or OOOOa affected storage tank with control device</i>	\$2,868	\$10,377	\$1,434	\$5,198
	<i>Sites with existing Subpart OOOO or OOOOa affected compressor with control device</i>	\$716	\$2,581	\$358	\$1,291

¹. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2 Retrofit Costs for Control Devices. Inclusion of these costs would only further increase the cost effectiveness ratios.

After accounting for the non-year round operation of pneumatic pumps, it is again the case that the only clearly reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the proposed rule. As explained in more detail earlier in these comments, the probability of this occurring is near zero. The case of control with a device that is subject to the storage vessel control requirements under Subpart OOOO result in marginal cost effectiveness, but only under the multipollutant scenario.

This illustrates the need for EPA to revise the proposed rule's approach to performance testing and monitoring for control devices and closed vent systems used for pneumatic pump affected sources as previously explained earlier in these comments.

Note: The above conclusions are drawn even without accounting for the additional costs for recordkeeping and reporting, which were also not considered by EPA when evaluating the cost effectiveness of pump control options.

24.3.2 EPA Did Not Consider Or Provide For Instances Where Routing A Pneumatic Pump Affected Source To An Existing Control Device Is Not Technically Feasible Or Where The Control Device Belongs To Another Party

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

In some instances an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

EPA should provide exclusion in the rule such that routing a pneumatic pump affected source to an existing control device or closed vent system is not required if it is not technically feasible or if the control device is not owned and operated by the site operator. Proposed updated rule language is included in 24.4.1.

If needed, EPA could provide provisions in the rule for an operator to make an engineering determination that an existing control device cannot technically handle the additional gas from a pneumatic pump affected source exhaust, document this determination, and make such a determination available for inspection by EPA or other competent authority.

24.3.3 EPA Did Not Consider How This Rule And Its Requirements To Route Pneumatic Pumps To Control Devices Can Potentially Trigger Permitting Requirements.

Under the proposed Subpart OOOOa, EPA is requiring that the exhaust from pneumatic pumps be controlled by control devices if those devices are present on site.

EPA's analysis of the proposed approach to pneumatic pumps has ignored the fact that such an action may require amending the air permit for a facility simply due to a replacement in kind of a pump under Subpart OOOOa. Many state new source review (NSR) programs require permits, simply because an NSPS or NESHAP requirement applies, even if a permit is not otherwise required. Additionally, the exact requirements will vary based on the local permitting requirements, but in many cases, the act of tying a new stream into a combustion control device will result in a change in emissions from a site due to the rerouting, which can trigger permitting. Local permitting requirements are very sensitive to the reality

that control devices are subtle and complex engineering structures that have very real physical limits. As discussed above, EPA's proposal for natural gas pneumatic pumps under Subpart OOOOa seems to ignore these physical realities.

EPA has not accounted for any time or expense associated with this permitting action, nor have they considered any of the additional burden on permitting authorities. These impacts should be quantified and considered prior to finalizing Subpart OOOOa regulatory text that may trigger state permitting requirements. One alternative to this concern is to revise the affected source criteria so that a pneumatic pump would not be an affected source, if it was connected to a control device on site. This could be accomplished by revising the text of 60.5365(h)(2) as follows:

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump ~~for~~ which **has not been connected to** a control device **when one** is located on site.

An additional advantage of this approach is that it clearly removes the addition of monitoring and performance testing currently in the proposed rule. As discussed in Sections 24.3.1 and 24.5.2, these costs were not included in EPA's cost effectiveness analysis, nor should compliance assurance requirements from OOOOa be required for a control device that was installed for another purpose.

Note that there are additional revisions to §60.5365a(h)(2) proposed in Sections 20.0, 24.4.1, and 24.4.5 to address separate applicability issues should EPA decide to regulate pumps as proposed.

24.3.4 EPA Overstated The Emissions, And Therefore The Benefits, Of The Proposed Requirements For Pneumatic Pumps

EPA has overestimated the emissions from diaphragm pumps. As EPA notes in Section 7.1 of the TSD: "Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks." As such, these pumps only during the winter season which represents a fraction of the year on average. Yet, EPA has assumed these pumps operate 8,760 hours per year when estimating emissions. This assumption grossly inflates the actual emissions from these sources. A more realistic estimate would be that these sources would operate 3-4 months during the course of the year and rarely more than 8 months per year. Using this more realistic estimate of hours of operation, the values in Table 7-17 change dramatically for diaphragm pumps – both in terms of emissions reduced and gas recovered by use of a VRU. Also, using diaphragm pumps to circulate heat-trace fluids is only practiced in climates with cold winters (e.g. Wyoming) and does not occur in warmer climates.

Diaphragm pumps are also used intermittently to transfer bulk fluids such as engine oil or emptying a sump. When used for these types of service they do not run for long periods, are not large emission sources and should not be subject to regulation under Subpart OOOO.

API recognizes the need for EPA to simplify analysis for assessing cost benefits for this rulemaking. EPA presents values in Table 7.2 which are based on a number of assumptions. It should be noted that the exhaust rates from pneumatic pumps are, in reality, based on assumed pump rate, a gas-supply pressure, and a pump model. All of these values vary considerably from site to site and even from pump to pump on a given site. When one reviews several manufacturer's pumps, it is readily apparent that they all have a multiplier factor for calculating required supply pressure and allowable exhaust pressure and these factors vary by over two orders of magnitude from one pump model to the next.

24.3.5 Electrical Power Is Not Available At Most Well Sites And Can Be Very Costly To Connect When It Is Available Nearby.

In the preamble, EPA requested comments on the availability of a constant, reliable source of electrical power at facilities throughout the oil and natural gas source category (FR 56625). “Electrical power” is typically taken as either grid power or locally-generated power. Generally, locally-generated power is solar power. These two power sources will be addressed separately.

Grid power is often not available in oil and natural gas producing sites due to their very remote nature. When grid power is available, it can be costly for oil and natural gas operators to establish a connection to the grid. Due to the significant cost associated with connecting to the grid, the payback on the capital costs of running grid power to well sites to replace a pneumatic pump with an electric pump is generally too long (often hundreds of years) to be considered. Further, API member company experience is that well sites often receive low priority behind others (hospitals, schools, residences, businesses, etc.) for connection services.

That said, when grid power is available, operators likely already utilize it to the extent possible for powering and monitoring of operations. If grid power were available, it would often be effective and efficient to electrify pumps rather than converting pneumatic pumps to instrument air. The use of electric motor driven pumps is a mature technology that is widely and typically used when reliable grid supply is available. Electric motor driven pumps also tend to be more reliable and more energy efficient than pneumatic driven pumps. Conversely, installing air compressors would be more expensive and less efficient. Instrument air systems are only economically feasible at sites where the pneumatic supply gas demand is sufficient to justify the capital and operating expense of an instrument-air compressor. At single well sites and even multi-well pads this is rarely the case, and the economics of electric pumps and controls are better than the economics of installing instrument air.

While the use of electric motor driven pumps is mature, the problem is that pumps tend to require a significant power load – a load that is far better suited to grid power than solar power. While solar pumps are sometimes an option, especially for low flow chemical injection pumps with low actuation frequency, as API pointed out in prior comments on the White Paper, there are limitations to their usage. For example, the White Paper noted that larger volume capacity solar operated pumps with high discharge pressures are available. This is not a valid conclusion from API's experience or from the source cited by EPA (U.S. EPA, 2011b). Only the smallest of jobs requiring wellsite pumping are suitable for solar-powered pumps.

24.3.6 Glycol Dehydrator Circulation Pump Emissions Vary, But Are Limited By Other Existing Regulations.

In the preamble, EPA requested comments and additional information on the level of uncontrolled emissions from glycol dehydrator lean-glycol circulation pumps, how they are vented through the dehydration system, and the amount and characteristics of VOC and methane emissions from uncontrolled glycol dehydrators. (FR 56627)

API believes that the dehydrator units with the highest potential VOC and methane emissions are already being controlled as a result of 40 CFR 63 Subparts HH and HHH either to meet the MACT control requirements or to take an enforceable limit on benzene emissions for the less than 1 TPY benzene applicability exemption. The use of combustion devices to control HAP emissions from dehydrator units also reduces VOC and methane emissions.

24.4 Applicability/Definitions

24.4.1 The Rule Should Have An Exemption For Limited Use/Low Emission Pumps Such As Chemical Injection Pumps.

API believes EPA's intent to regulate pneumatic pumps that have lower emission rates than continuous low bleed pneumatic controllers is inappropriate. EPA has previously determined that continuous bleed pneumatic controller devices emitting less than 6 scf/hour did not require control and EPA continues to support that position in the Subpart OOOOa rule proposal. EPA's Technical support document shows the assumed emission rate from pneumatic piston (chemical and methanol) pumps to be 2.48 scf/hour, which is less than half the 6 scf/hr threshold for continuous bleed pneumatic controllers. The cost effectiveness of controlling such low emitting pumps is substantially above EPA's assumed \$285/ton as described Section 22.3.1. Piston pumps in services with emissions below 53,000 scf/year (approximately equivalent to 6 scf/hour annualized) should be exempt due to the low volume of gas exhausted. Demonstration of emissions below this threshold should be a one-time engineering calculation for individual pumps or a class of pumps in similar service - for example chemical/methanol pumps below a pressure & volume combination which would yield exhausted volumes above the threshold.

There are also natural gas-driven pneumatic pumps, typically diaphragm pumps, which are used intermittently to transfer bulk liquids. These are generally either manually operated as needed or are triggered by a level controller. For instance, there are engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, separator knockout drum pumps, etc. that are used to pump liquids from one place to another. These pumps do not run continuously or even seasonally for long periods, but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, there should be an annual venting limit and an exemption for intermittently operated pumps.

EPA should provide an exemption under the rule for any pump emitting at a rate less than the rate of a continuous low bleed pneumatic controller. Specifically, any pneumatic pump which emits less than 53,000 scf/year (i.e. 6 scf/hour for an entire year) should be exempted. This would provide a reasonable exemption for intermittent use pneumatic pumps which do not have large aggregate emissions, including diaphragm pumps that are operated manually, triggered by a level controller, or operated temporarily or seasonally.

Alternatively, EPA could use the operating time of a pump with exhaust rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document) that would result in 53,000 scf/year of emissions, which is 96.5 days. This could be rounded down to 90 days of operation, or 2,160 hours. This approach would simplify the exemption, as companies would track the hours of operation instead of calculating the exact exhaust rate.

API proposes the following amendments to §60.5365a(h)(1) and (h)(2):

“(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump **with an exhaust rate greater than 53,000 scf/yr and that operates more than 2,160 hours per year.**

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump **with an exhaust rate greater than 53,000 scf/yr and that operates more than 2,160 hours per year, and for which a control device owned and operated by the owner and operator of the pump is located on site and not demonstrated to be technically infeasible to control.”**

Note that there are additional revisions to §60.5365a(h)(2) proposed in Section 20 and 24.4.5. See 24.4.5 for combined language.

24.4.2 The Rule Text Should Exempt Portable Pneumatic Pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. Since these pumps will, by their very nature, result in very low emissions, portable pumps should be exempt from the rule. Such an exemption would be analogous to that provided to portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform) engines relative to the NSPS RICE rules.

API recommends that EPA update the definition of pneumatic pump under the rule to exclude temporary and portable pumps.

EPA should amend the definition under §60.5430a to address these temporary and portable sources, i.e. “A temporary or portable pump is considered a stationary source under this rule if it stays in one location for more than 12 months (or full annual operating period of a seasonal source).” (See revised definition under 24.4.3.)

24.4.3 The Rule Text Should Be Clearer On Exclusion Of Lean Glycol Circulation Pumps (Often Referred To As Kimray Pumps) On Dehydration Units (As Intended By The Preamble Language).

EPA's intent is clear in the Preamble (FR 56627) that EPA is not proposing to regulate gas assist lean glycol circulation pumps on glycol dehydration units. However, the regulatory text does not make this exclusion clear.

EPA can improve this by having a single modified definition under §60.5430a rather than two inconsistent definitions for chemical/methanol or diaphragm pumps and natural gas-driven chemical/methanol or diaphragm pumps. Neither defined term is used in the rule text itself which is also confusing.

API proposes an updated definition under §60.5430a as follows:

Remove the following definition:

~~“Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection.”~~

API recommends adding following definition:

Natural gas-driven chemical/methanol or diaphragm pump *means* a natural gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A lean glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a stationary source under this rule if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source).

24.4.4 The Rule Should Allow For Removal Of Control Device – i.e. Pneumatic Pump No Longer Has To Be Controlled If Control No Longer Present.

If a control device is no longer needed for the purpose for which it was originally installed, EPA should clarify that any pneumatic pumps that were routed to the device should no longer require control. A control device should not be required to remain in service only for the purpose of controlling one or more pneumatic pumps.

For example, NSPS Subpart OOOO allows for removal of control device from a storage vessel if emissions fall below a certain level. Specifically, under the NSPS, EPA has allowed for the removal of control devices once emissions are below 4 TPY (40 CFR 60.5395(d)(2) and 60.5395a(a)(3)). In the preamble to the NSPS OOOO revisions dated April 12, 2013 (Federal Register Vol. 78, No. 71, 22133-22134) EPA also noted that removal of control at 4 TPY will help relieve the control device shortage issue as well as reduce emissions from burning more pilot gas than the waste gas being burned. If a control device is removed, the requirement to route pneumatic pump exhaust to the control device should no longer be applicable.

24.4.5 EPA Must Define “Control Device” In The Context Of Its Use In The Requirements For Pneumatic Pumps

§60.5365a(h)(2) states:

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.

Control device is not a defined term and should be specifically defined to clarify EPA's intent which, from review of the complete NSPS OOOOa proposal and TSD, appears to be to utilize combustion control devices and/or VRUs if available. This issue is discussed in Section 13.0, and a definition recommended that will eliminate the issues related to the uncertainty of when the pneumatic pump requirements apply.

However, if EPA does not elect to incorporate API's suggested changes in Section 13.0, then EPA must make revisions within §60.5365a(h)(2) to clarify this situation. Specifically, API recommends the following change:

§60.5365a(h)(2) *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.*

For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.

Note that there are additional revisions to §60.5365a(h)(2) proposed in Section 20 and 24.4.1.

Combining the edits in Sections 20, Section 24.4.1, and this Section results in:

§60.5365a(h)(2) *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump that meets the criteria in paragraphs (i) through (iii) and is not excluded by (iv).*

- (i) The pump has an exhaust rate greater than 53,000 scf/yr and operates more than 2,160 hours per year.*
- (ii) The pump has a control device owned and operated by the owner and operator of the pump is located on site. For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.*
- (iii) The pump has not been demonstrated to be technically infeasible to control.*
- (iv) A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.*

24.4.6 The Control Device Must Be Owned And Operated By The Pump Owner And Operator

EPA must be clear that a control device on site must be owned and operated by the same company that owns and operates the pumps. For instance, the dehydration unit located on a production site may be owned and operated by the gathering company, not the producer. If there is a dehydration unit on site with a control device that is owned and operated by the gathering company, the producer has no right to route pump exhaust to the control device and should not be required to route the pump exhaust to the dehydration control device owned and operated by a separate entity.

24.4.7 Heaters Should Not Be Considered As Existing Control Devices – I.E. Pneumatic Pump Exhaust Should Not Be Required To Be Routed To A Heater Simply Because One Is Present.

The language in §60.5412a describes requirements that each control device must meet and this list includes process heaters. This language could be misinterpreted to mean that any process heater should be considered a control device and thus, its presence would require routing of a pump exhaust to the heater. It is not believed that this was EPA's intent.

EPA should clarify that routing emissions to a process heater should be considered "routing to a process" and the heater should not be considered as a control device. More discussion on this topic is provided in section 13.0. However, if EPA does not elect to incorporate API's suggested changes in section 13.0, then EPA must make revisions in §60.5365a(h)(2) to clarify this situation. The recommended changes are shown above in section 24.4.5.

See Section 13.0 of these comments for a complete discussion of the issues associated with treatment of heaters and boilers in Subpart OOOOa.

24.4.8 Non-Affected Facilities (E.G. Pumps Not Requiring Controls Under The NSPS) Should Not Have Obligations Under The Rule.

Under §60.5360a(h)(2), EPA has defined that the OOOOa affected source for pneumatic pumps "for locations other than natural gas processing plants" is a "a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site." However, under §60.5410a(e)(3) and §60.5420a(b)(8)(i), EPA is proposing that you must submit a certification if the pneumatic pump is not controlled by 95% because a control devices is not available at the site.

A pump at a site without a control device is not an affected source and should not have requirements under OOOOa. EPA should remove the requirements requiring certification for pumps located at sites without control devices.

API recommends that §60.5410a(e)(3) and §60.5420a(b)(8)(i) should be removed from the proposed rule.

24.5 Reporting and Recordkeeping**24.5.1 Remove The Tagging Requirement.**

It is unclear what EPA's intent is for requiring tagging of affected natural gas driven pneumatic pumps under §60.5393a(a)(2), §60.5393a(b)(3) and §60.5410a(e)(4). The applicability is clear that if the pump is new, modified, or reconstructed after September 18, 2015, not at a natural gas processing plant, and with a control device on site. The tagging appears to add little value.

Furthermore, it is confusing that tagging be required for pneumatic pumps that are not affected facilities because a control device is not on-site (as required by §60.5410a(e)(4)).

API requests that EPA remove the following paragraphs related to tagging:

~~§60.5393a(a)(2): Each pneumatic pump-affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).~~

~~§60.5393a(b)(3) Each pneumatic pump-affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).~~

~~§60.5410a(e)(4) You must tag each new pneumatic pump-affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).~~

Alternatively: API requests that EPA at least limit tagging such that it is only required for pumps with a control device on site for which control has been determined to be technically infeasible.

24.5.2 EPA Should Remove The Recordkeeping Requirements For Control Devices And Closed Vent Systems

As discussed in Section 24.3.1, EPA's costs for controlling pneumatic pumps not located at a natural gas processing plants did not include the cost of the recordkeeping and reporting requirements in the cost estimate. The recordkeeping and reporting requirements that EPA has included are burdensome in some cases and expand requirements to non-affected sources.

- §60.5420a(b)(8)(i) requires certification of non-affected sources (See also Section 24.4.8).
- §60.5420a(b)(8)(v) requires testing data to be submitted that is not accounted for in the cost analysis, not cost effective when included, and not needed based on the exhaust gas being natural gas, which is the same as the pilot of the combustion device. EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements.
- §60.5420a(c)(16)(i) – It is not clear what EPA means by records of “the manufacturer specifications”. EPA should clearly specify what they want here. It is assumed this refers to the make and model of the pump.
- §60.5420a(c)(16)(iii) – This provision requires continued tracking of the data of a pump being constructed, reconstructed, or modified at a non-natural gas processing plant location that did not have a control device that later has one installed. Pumps should only be triggered at the time the pump is installed. Labor intensive compliance tools will be required to track the location of the pumps as they move from site to site. The cost of these systems and the manpower to maintain them were not included in EPA's cost of control.
- §60.5420a(c)(16)(iv) – As discussed in Section 24.3.1, EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements as they are not accounted for in the cost and not cost effective once included.
- §60.5420a(c)(16)(v) appears to reference the wrong requirements in the rule. It shows that the photograph with latitude and longitude would be a substitute for the records for

the control device monitoring and testing. It should refer to the location, make, and model requirements under (i).

In many instances, these controls have been installed under a state permit (or other regulatory requirement) and have compliance assurance requirements associated with those requirements. It is inappropriate to add new compliance assurance requirements that may conflict to the original requirements the control device was installed to meet. Additionally, the control device may not be able to meet or be retrofitted to meet (i.e. install sample ports) to meet the compliance assurance requirements of OOOOa.

API recommends the following amendment to the rule language §60.5420(b) and (c):

§60.5420(b)(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (v) of this section.

- ~~(i) In the initial annual report, a certification that there is no control device on site, if applicable.~~
- (ii) An identification of each pneumatic pump constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5393a(a)(2) or (b)(2).
- (iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.
- (iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.
- ~~(v) If complying with §60.5393a(b)(1) with a control device tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e), records specified in paragraphs (e)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

§60.5420a(c)(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(1)(i) through (iv) of this section.

- (i) Records of the date, location and ~~manufacturer specifications~~ make and model for each pneumatic pump constructed, modified or reconstructed.
- (ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.
- ~~(iii) Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~
- ~~(iv) Except as specified in paragraph (e)(16)(iv)(G) of this section, records for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5393a(b)(1) for each pneumatic pump.~~
 - ~~(A) Make, model and serial number of purchased device.~~
 - ~~(B) Date of purchase.~~
 - ~~(C) Copy of purchase order.~~
 - ~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~
 - ~~(E) Inlet gas flow rate.~~
 - ~~(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (e)(16)(iv)(F)(1) through (4) of this section.~~
 - ~~(1) Records that the pilot flame is present at all times of operation.~~

~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~

~~(3) Records of the maintenance and repair log.~~

~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

(G) As an alternative to the requirements of paragraph (c)(16)(i)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

25.0 STORAGE VESSELS

25.1 The Language For Applicability In Subpart OOOOa Needs To Be More Clear About Tanks That Do Not Receive Liquid From Hydraulically Fractured Wells (Time Limit)

Proposed paragraph §60.5365a(e) specifies that the potential for VOC emissions must be calculated “for a 30-day period of production prior to the applicable emission determination deadline specified in this section.” Paragraph §60.5365a(e)(1) then specifies this deadline for storage vessels receiving liquids from well affected facilities (i.e., a hydraulically fractured wells with a GOR greater than 300 scf/bbl) as “30 days after startup of production.” There are multiple issues with this paragraph.

First, there are no deadlines specified for newly constructed, reconstructed, or modified storage vessels that receive liquids from sources other than hydraulically fractured wells. Presumably, EPA intends that such tanks with potential VOC emissions greater than 6 tons per year would be subject to the rule.

Second, for tanks that are not installed at the onset of production for a well, the 30 days after startup of production is not relevant. Rather, this period should be based on 30 days after the storage vessel is put into service.

Therefore, API recommends the following amendments to the proposed provisions of §60.5365a(e) and (e)(1).

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in **paragraph (e)(1) of** this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(e)(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production (**i.e., the date that the storage vessel is placed into service**).

25.2 EPA Should Provide Clarity For The Process For Assessing Applicability For Replacement Tanks

Proposed paragraph §60.5365(e)(4) attempts to provide the requirements for determination of applicability for storage tanks that replace existing tanks. However, this paragraph is very confusing in existing OOOO, thus leaving the regulated community and state and local air pollution agencies reeling. This has resulted in various and inconsistent interpretations and policies in the implementation of Subpart OOOO. API recommends that EPA correct these issues in Subpart OOOOa.

Paragraph (e)(4) specifically applies to “each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service”. While there are numerous questions and issues related to “returned to service” that are discussed below, the tanks EPA that is attempting to address by “each new, reconstructed, or modified storage vessel with startup of production” is not clear. These criteria would apply to every storage vessel, leaving question about the relationship between the basic applicability provisions in paragraph (e) apply versus those in (e)(4). API believes that it is EPA’s intent that paragraph (e)(4) apply to storage vessels that replace existing storage vessels. There are various scenarios under which a tank may be added. For several of these scenarios, the existing provisions in Subpart OOOO, and the proposed provision in Subpart OOOOa, are not clear. Table 22-1 describes those scenarios, along with API’s interpretation of EPA’s intention. After the scenarios, API provides suggested regulatory language to clarify these situations moving forward.

Table 25-1 Interpretation of EPA’s Intention for the Applicability of the Storage Vessel Provisions Subparts OOOO and OOOOa for Various Scenarios

<i>Scenario</i>	<i>Interpretation of EPA’s Intention for Determining Applicability for Storage Vessels</i>
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at a new site.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins at the startup of production (<i>when the storage vessel is put into service – see recommendation above</i>)
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site but not as a replacement for an existing tank.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins when the storage vessel is put into service
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site as a replacement for an existing tank that was a storage vessel affected facility subject to Subpart OOOOa.	The new storage vessel is an affected facility subject to Subpart OOOOa.
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site as a replacement for an existing tank that was a not a storage vessel affected facility subject to Subpart OOOOa.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins when the storage vessel is put into service.
A storage vessel constructed, reconstructed, or modified prior to September 18, 2015 is added at any site (even if it is a replacement for an existing tank that was a storage vessel affected facility subject to Subpart OOOOa.)	The storage vessel is not an affected facility subject to Subpart OOOOa.
A storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service that is reconnected to the original source of liquids.	The storage vessel is an affected facility and subject to Subpart OOOOa.
A storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service that is put back into service at a different location.	See scenarios 1 through 4.

API suggests the following that proposed §60.5365a(e)(4) be entirely replaced with the following, and that (e)(5) be added as follows.

(4) Each storage vessel that was constructed, reconstructed, or modified after September 18, 2015 that replaces an existing storage vessel shall determine applicability according to the provisions in (e)(4)(i) or (ii).

(i) If the storage vessel being replaced is a storage vessel affected facility, the new storage vessel is an affected facility.

(ii) If the storage vessel being replaced is not a storage vessel affected facility, applicability shall be determined in accordance with paragraph (e) and (e)(1) of this section.

(5) Each storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service in accordance with §60.5395a(c) that is put back into service shall determine applicability according to the provisions in (e)(5)(i) or (ii).

(i) If the storage vessel is reconnected to the original source of liquids, it is a storage vessel affected facility subject to the same requirements as before being removed from service.

(ii) If the storage vessel is put back into service and not reconnected to the original source of liquids, applicability shall be determined in accordance with paragraph (e)(4) of this section.

API would also recommend that analogous changes be made to §60.5365(e).

25.3 EPA Should Clarify That Hydraulic Fracturing Or Refracturing Does Not Constitute A Modification To A Tank.

When a well is refractured, it is likely that the storage vessel that receives the liquids from the well will see an increase in throughput from the time period just prior to the refracture (even though it is unlikely that it will increase throughput from the original throughput). Proposed paragraph §60.5365a(a)(3) is clear that in this situation, refracturing a well does not affect the modification status of other downstream equipment, including storage vessels. API supports this clarification.

However, the rule does not address similar situations where well activity could increase the throughput of a tank for which Subpart OOOOa applicability has already been determined. A few examples include when a new well (hydraulically fractured or not) is tied into the storage vessel, when another storage vessel at the site is taken out of service, or the liquids flow at a site with multiple tanks is altered.

To clarify these situations, API suggests the addition of a paragraph §60.5365a(e)(6). Suggested language is as follows:

(6) For the purposes of this Subpart, after the initial applicability determination for a storage vessel has been conducted in accordance with the requirements of paragraph (e) and (e)(1), situations that increase the throughput of that storage vessel shall not be considered modifications and shall not require a new applicability determination.

25.4 EPA Should Modify The Definition Of “Maximum Daily Average Throughput” To Reflect Their Intentions Regarding Storage Tank Applicability Determinations

For the applicability determination for storage vessel affected facilities, proposed §60.5365a(e)(1) requires that the emissions must be calculated “The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section.” While the term “maximum average daily throughput” is both a plain language and mathematical contradiction, EPA attempted to clarify this term in proposed §60.5430a. This definition is as follows:

“Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.”

While this definition clarifies the “maximum average” aspect of the term, there are still numerous issues that need to be addressed with this definition.

First, the inclusion of the word “earliest” is problematic and it adds no value. Proposed §60.5365a(e) requires that “you must determine the potential for VOC emissions within 30 days after startup of production.” Since the determination must be done for a 30-day period within 30 days after startup of production, there is only one 30 day period. The period is well defined. Therefore, EPA should remove the word “earliest” from this definition.

Second, requiring the maximum daily average to be calculated based strictly on a calculation of the average throughput for the first 30 days of production does not recognize the situations experienced in practice. The determination should be based on the maximum daily throughput at steady state conditions, which is often not likely represented by the calculation of the average throughput for the first 30 days. It is true that typically the initial 30-day period will represent the maximum production the well is expected for the life of the well due to reservoir depletion. However, the first 30-days of production are typically non-steady state operations, containing both shut-in periods for operational reasons and short, spike flow periods (minutes to hours) after the production valves are opened after the well has been shut-in. Including either the peak flow periods or shut-in periods adulterates the average throughput experienced during the initial 30 days of production. Basing the determination solely on the average throughput for this period could result in tanks with the potential to emit VOC at levels much higher than 6 tons per year not being subject (e.g., if there were multiple shut-in days), and tanks with potential VOC emissions much lower than 6 tons per year being subject (e.g., if there were numerous spikes). The appropriate throughput, which is entirely consistent with EPA’s intention, is that the applicability determination be based on maximum daily throughput during the initial 30-day period that represents steady state conditions. Finally, the concept of generally accepted methods is already clear in §60.5365a(e). Repeating it in the definition of maximum average daily throughput is unnecessary and potentially confusing.

Therefore, API suggests the following change to the proposed definition of maximum average daily throughput.

“Maximum average daily throughput means the ~~earliest calculation of~~ daily average throughput during the 30-day PTE evaluation period ~~that represents steady-state conditionsemploying generally accepted methods.~~”

25.5 Under §60.5395a(A)(3), The Re-Installation Of Controls To Achieve 95% Should Not Be Required When Liquids From The Well Following Fracturing Or Refracturing Are Routed To The Storage Vessel Affected Facility If Emissions Do Not Increase To Greater Than 4 TPY

Section §60.5395a(a)(3) includes an alternative emission limitation to allow for situations when production declines and the uncontrolled VOC emissions from the storage vessel fall below 4 tpy for 12 consecutive months. This is entirely consistent with the requirements in §60.5395(a)(3) of Subpart OOOO. In the preamble for the final amendments that added this alternative to §60.5395(a)(3) of Subpart OOOO, EPA stated the following:

“In light of the cost effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emission from storage vessel affected

facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy.” (78 FR 58429, September 23, 2013)

In proposed §60.5395a(a)(3)(ii), controls would need to be re-instated if the emissions increase to 4 tpy or greater based on one month's emissions. API does not take issue with this requirement.

However, paragraph §60.5395a(a)(3)(i) also requires that controls be re-instated if the well feeding the storage vessel affected facility undergoes fracturing or refracturing as soon as liquids are routed to the storage vessel, without regard to the VOC emissions level. This requirement is consistent with Subpart OOOO. EPA justified this by stating that this situation is “likely to release substantial amounts of vapor if not controlled right away due the initially high liquid flow and flash emissions from freshly fractured or refractured wells. We also believe that potential emissions associated with fracturing and refracturing of a well are unlikely to meet the 4 tpy uncontrolled emission rate.” (78 FR 58431, September 23, 2015)

API does not believe that this requirement is warranted. While it is true that production, and storage tank emissions, would likely increase after the fracturing or refracturing, EPA cannot arbitrarily assume that this reduction would automatically result in VOC emissions greater than 4 tpy. EPA provided no data to support this assertion. EPA has clearly stated that BSER is not represented by control when emissions are less than 4 tpy, and this requirement has the clear potential to require control on tanks that is at a level that EPA has clearly determined is not cost effective.

Therefore, EPA should remove paragraph §60.5395a(a)(3)(i) and only rely on the requirements currently in paragraph §60.5395a(a)(3)(ii); if indeed the fracturing or refracturing does result in a VOC emissions level greater than 4 tpy, then the tank would be required to be controlled for at least the next 12 months. However, if the VOC emissions were below 4 tpy after the fracturing or refracturing, this would not result in the re-installation of controls that are clearly not cost effective.

Therefore, API recommends the following change to the final Subpart OOOOa.

§60.5395a(a)(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section **within 30 days of the monthly determination** if the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater: ~~your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.~~

~~(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.~~

~~(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.~~

API also requests that the same changes be made to §60.5395(a)(3) of Subpart OOOO.

Another alternative would be for EPA to require control immediately as required in paragraph (ii), but then allow controls to be removed after 30 days if the increased production levels would not result in VOC emissions greater than 4 tpy. API does not recommend this solution as the installation costs of a

control device can be substantial, but it would be preferred to the proposed requirement that would require that controls be operated for 12 additional months (when uncontrolled VOC emissions never exceeded 4 tpy) before they could be removed.

25.6 Emission Limits/Control Devices

25.6.1 EPA Cannot Retroactively Add Control Requirements To Subpart OOOO.

EPA proposed, as §60.5412(d)(1)(iv), several new requirements for combustion devices used to meet the storage vessel emission reduction standard in §60.5395(d). Specifically, this paragraph would require that each combustion devices be designed and operated in accordance with one of the following four performance requirements.

- Reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.
- Reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.
- Operate at a minimum temperature of 760°C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §60.5413.
- If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

First, Subpart OOOO currently only requires, in §60.5412(d)(1), that each enclosed combustor be “designed to reduce the mass content of VOC emissions by 95.0 percent or greater.” The addition of these proposed requirements in §60.5412(d)(1)(iv) means that an owner/operator fully in compliance with the current provisions in §60.5412(d)(1) could find themselves unable to comply with the new requirements in §60.5412(d)(1)(iv).

Second, the first three options require that compliance be demonstrated in accordance with §60.5413. However, the requirements in §60.5413(b), which would be used to demonstrate compliance with these options, do not apply to control devices for storage vessel affected facilities. Specifically, the introduction to §60.5413 indicates that “This section applies to the performance testing of control devices used to demonstrate compliance with the emission standards for your centrifugal compressor affected facility.” The only requirements contained in §60.5413 that apply to storage vessels are those in paragraph (d), which are specific to combustion devices tested by the manufacturer. As discussed in more detail below in section 6.6, EPA did not propose any testing requirements for storage vessel combustion devices not tested by the manufacturer. Therefore, the reference to §60.5413 proposed in §60.5412(d)(1)(iv)(A) through (C) has no context.

For these reasons, EPA must not finalize the proposed requirements in §60.5412(d)(1)(iv)(A) of Subpart OOOO.

25.6.2 EPA Has Not Justified The Change To Route Storage Vessel Emissions To A Process That Achieves 95% Control.

In proposed Subpart OOOOa, §60.5395a(b)(1) requires that emissions from storage vessel affected facilities be routed through a closed vent system to a control device that meets the requirements of

§60.5412a(c) and (d). It also provides that, as an alternative, these emissions may be routed through a closed vent system “to a process that reduces VOC emissions by at least 95.0 percent.”

API objects to this 95 percent requirement, as EPA has not provided any justification or rationale for its inclusion. Therefore, it must be removed.

First, it is inconsistent with the analogous requirements for storage vessels in §60.5395(b)(1) of Subpart OOOO, as well as the requirements in A.2(b)(1) of the draft CTG. Further, the proposed parallel proposed requirements for centrifugal compressors at §60.5380(a)(2) and pneumatic pumps at §60.5393(b)(4) do not include this requirement. EPA has not explained or justified why this requirement would apply only to storage vessel affected facilities subject to Subpart OOOOa.

Second, EPA did not include any explanation or process in the proposed Subpart OOOOa detailing how to demonstrate compliance with this requirement. EPA did not provide any technical or other justification for the inclusion of this additional requirement when emissions from a storage vessel affected facility are routed to a process. In fact, API does not find any mention of the addition of this requirement in the preamble.

Finally, the CVS requirements in proposed paragraph §60.5411a(c)(2) already require that CVS be operational 95 percent of the year or greater when emissions are routed to a process. This further makes the proposed requirement in §60.5395a(b)(1) unnecessary.

Therefore, EPA should make the following change to the proposed requirements in §60.5395a(b)(1) for the final rule:

§60.5395a (b) Control requirements. (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c), and you must route emissions to a control device that meets the conditions specified in §60.5412a(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process ~~that reduces VOC emissions by at least 95.0 percent.~~

25.7 Testing and Monitoring

25.7.1 EPA Must Clarify That No Performance Testing Requirements For Storage Vessel Affected Facilities Were Proposed For NSPS Subpart OOOO

Throughout the preamble, EPA discusses the implementation improvements made as a result of the reconsideration of issues raised in administration reconsideration petitions on the 2012 final rule. One of the major implementation improvements is related to the performance testing requirements for control devices used to comply with the storage tank requirements. For example:

“In this rulemaking, the EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues, which mostly address implementation, are as follows: storage vessel control device monitoring and testing provisions, .” (80 FR 56598)

“As proposed, initial and ongoing performance testing will be required for any enclosed combustors used to comply with the emissions standard for an affected facility and whose make and model are not listed on the EPA Oil and Natural Gas Web site Performance testing of combustors not listed at the above site would also be conducted on an ongoing basis, every 60 months of service, and monthly monitoring of visible emissions from each unit is also required.” (80 FR 56645)

These statements are reflected in proposed Subpart OOOOa. Specifically, §60.5410a(h)(4) and §60.5413a(b)(5)(i) both would require that initial performance tests be conducted “within 180 days after initial startup.” In addition, §60.5410a(h)(4) adds “or within 180 days of [date 60 days after publication of final rule in the **Federal Register**], whichever is later”. While this inconsistency creates confusion for those sources that have a startup date prior to 60 days after publication of the final rule, it is clear that EPA intends to require initial performance testing for control devices used to comply with the Subpart OOOOa storage vessel requirements. The periodic performance testing requirements are also clear in Subpart OOOOa, as both §60.5413a(b)(5)(ii) and §60.5417a(h)(4) would require periodic tests every 60 months after the initial test.

API notes that the initial and periodic performance test requirements for storage vessel control devices in the model rule language in the draft Control Technique Guidelines released by EPA on September 18, 2015 (80 FR 56577) is consistent with the proposed Subpart OOOOa.

However, it is not clear whether EPA intended to include these same performance testing requirements in the proposed amendments to Subpart OOOO. There are no amendments proposed that would require an initial performance test for storage vessels. In Subpart OOOO, no paragraph was added to §60.5410(h) that is analogous to the initial testing requirement for storage vessels proposed in §60.5410a(h)(4), and §60.5413(b) only applies to control devices used to meet the centrifugal compressor requirements in §60.5412(a). Note that proposed §60.5413a(b) clearly states that the provisions in that section, including the initial testing requirements in §60.5413a(b)(5)(i), apply to control devices meeting the centrifugal compressor requirements in §60.5412a(a) and the storage tank requirements in §60.5412a(d).

Based on the lack of proposed amendments to Subpart OOOO described above, it could be assumed that EPA did not intend to apply testing provisions for storage vessel control devices for storage vessel affected facilities constructed, reconstructed, or modified between August 23, 2011 and September 18, 2015. However, this interpretation is clouded by the fact that EPA did propose to add paragraph §60.5417(h)(4), which requires periodic performance tests. However, it is unclear whether EPA intended to require periodic testing for storage vessel control devices subject to Subpart OOOO or whether this was an inadvertent inclusion.

Proposed paragraph §60.5417(h)(4) states:

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

Based on the rationale below, API concludes that EPA did not intend to require this testing for storage vessel affected facilities.

- The introductory text for §60.5410(h) indicates that in order to demonstrate continuous compliance for a storage vessel affected facility, the requirements of paragraphs (h)(1) through (3) must be met. This language was not amended to include a reference to paragraph (4). Therefore, technically, compliance with this paragraph is not required.
- Proposed §60.5417(h)(4) indicates that the periodic performance test be performed 60 months after the initial performance test as specified in §60.5413(b)(5)(ii). However, §60.5413(b)(5)(ii) applies only to centrifugal compressor affected facilities and, as discussed above, there is no requirement for initial performance testing for storage vessel affected facilities.
- The preamble did not indicate that these implementation improvements were applicable to Subpart OOOO.

- EPA clearly did not estimate the cost of testing in any of their justification for the proposed amendments to Subpart OOOO.

Therefore, EPA must remove the proposed §60.5410(h)(4) to clarify that clearly they did not intend to retroactively apply the implementation improvements related to storage vessel initial and periodic testing to storage vessel affected facilities subject to Subpart OOOO.

25.7.2 EPA Cannot Finalize Performance Testing Requirements For Storage Vessel Affected Facilities For NSPS Subpart OOOO

API recognizes the possibility that EPA did intend to require initial and periodic performance testing for storage vessel affected facilities under Subpart OOOO. If this was the case, EPA must not include such provisions in the final rule. As discussed above, EPA clearly did not propose such amendments on September 18, 2015. Therefore, the public did not have the opportunity to comment on such proposed requirements. Even if EPA attempts to claim that it was their intention to propose testing requirements for storage vessel affected facilities subject to Subpart OOOO, there are numerous aspects related to the addition of these requirements that would need to be included (e.g., When is the initial performance test required? What if the control device met the required to be “designed” to achieve 95% reduction but cannot meet achieve such reduction during a performance test?). EPA is not allowed to finalize such provisions without providing the opportunity for the public to comment.

If EPA elects to move forward and require initial and periodic testing of control devices for storage vessel affected facilities under Subpart OOOO, they must issue a separate proposal and allow the opportunity for the public to comment.

Further, as discussed below, the storage vessel testing and monitoring requirements proposed for Subpart OOOOa are inappropriate, infeasible, and unjustified.

25.7.3 API agrees that Continuous Parameter Monitoring is not warranted for Storage Vessel Control Devices

In NSPS Subpart OOOO, EPA proposed only two changes to the monitoring requirements for storage vessel control devices:

- (1) Visible emission tests would be required on a monthly basis (instead of quarterly) for manufacturer testing combustion devices - §60.5413(e)(3), and
- (2) The criteria for this visible emission test was modified as follows: Devices must be operated with no visible emissions, except for periods not to exceed a total of ~~2 minutes during any hour~~ 1 minute during any 15-minute period.

The requirements in proposed Subpart OOOOa are consistent with these changes to Subpart OOOO.

Notably absent are requirements to perform continuous parameter monitoring. API agrees that continuous parameter monitoring is not warranted and supports that EPA elected not to include such provisions in the proposed amendments to Subpart OOOO or the proposed Subpart OOOOa.

However, in the draft CTG model rule, the storage vessel control device monitoring requirements are considerably different. In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required. In our comments on the CTG, we explain how these monitoring requirements are unrealistic and unjustified.

This is a significant discrepancy in the proposed NSPS and draft CTG model rule monitoring requirements. If in fact the EPA intended for the NSPS monitoring requirements in both Subpart OOOO

and Subpart OOOOa to include continuous parameter monitoring as in the CTG, EPA must issue a separate proposal and allow the opportunity for the public to comment.

25.8 EPA Should Only Require Control When There is Flow into the Storage Vessel

Temporary shut-ins can result in a loss of gas supply to the flare pilot, rendering the control device non-operational. During such temporary shut-ins, working and flash losses from storage vessels cease completely because the producing well stopped flowing. A negligible amount of breathing loss (evaporation) emissions may continue to occur. The current language in §60.5412(d)(3) is:

You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device.

Thus, to control only the remaining, negligible breathing losses during a temporary well shut in, a supplemental source of fuel gas may need to be purchased to operate the pilot for a flare or combustor. In some cases that is not even a viable option due to the remoteness of the location and thus the temporary shut-in could result in a requirement to empty, degas and clean the storage vessel before conducting the maintenance activity that would result in a temporary shut-in. API suggests the following revision to §60.5412(d)(3) to address this issue.

§60.5412(d)(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes **from working or flash losses** are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

26.0 EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In §60.5416a, EPA proposes initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, EPA proposed a fugitive emissions program in §60.5397a that is also based on identifying and repairing leaks. As proposed, §60.5397a will also apply to covers and closed vent systems, as the definition of “fugitive emissions component” includes “closed vent systems,” and “thief hatches or other openings on storage vessels.” This results in covers and CVS being subject to both the leak detection and repair requirements in §60.5397a and the leak detection and repair requirements in §60.5416a. This creates a situation which is unnecessarily duplicative and redundant. Table 26-1 provides a summary of these overlapping requirements.

Table 26-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO

Affected Equipment/Components	§60.5416a		§60.5397a	
	Inspections	M21	OGI	M21
<i>Centrifugal Compressors and Pneumatic Pumps</i>				
closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (<i>e.g.</i> , a welded joint between two sections of hard piping or a bolted and gasketed ducting flange)	(a)(1)(ii) annual visual inspections for defects	(a)(1)(i) Initial, annual, and after repairs/replacements	(f) – (j) Initially, semiannually (could move to quarterly or	(j)(2) Option for use after repair/replacement

Affected Equipment/Components	§60.5416a		§60.5397a	
	Inspections	M21	OGI	M21
Closed vent system components other than a joint, seam, or other connection that is permanently or semi-permanently sealed	(a)(2)(iii) annual visual inspections for defects	(a)(2)(i) and (ii) Initial, annual, and after repairs/ replacements	annual depending on % leakers), and after repair/ replacement	
Covers	(a)(3) annual visual inspections for defects	n/a		
Storage Vessels				
Closed vent system	(c)(1) Monthly olfactory, visual and auditory inspections for defects	n/a	(f) – (i) Initially, semiannually (could move to quarterly or annual depending on % leakers), and after repair/ replacement	(j)(2) Option for after repair/ replacement
Covers	(c)(2) Monthly olfactory, visual and auditory inspections for defects			

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the Technical Support Document (Table 5-4 and Table 5-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with other NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in §60.5397a. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

26.1 Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in §60.5430. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

"Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an

emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards.”

API recommends the same definition of closed vent system be added to §60.5430a with an additional clarification (**bold**) that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

*Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.*

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of “routed to a process or route to a process” and “fugitive emissions component”, as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

26.2 Remove Cover and Closed Vent Systems Components from Definition of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of “fugitive emissions component” in §60.5430a needs to be modified.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, ~~flanges, closed vent systems, thief hatches or other openings on a storage vessels~~, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 27.2.1.

26.2.1 Remove Section 60.5416a

API recommends that all paragraphs of §60.5416a be removed. As shown in Table 26-2 every relevant requirement of §60.5416a will be addressed by referring to a requirement in §60.5397, or in the case of the bypass requirements, requirements in §60.5411a. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components. For example, API’s recommended changes would require OGI monitoring for all CVS and cover components, rather than the OVA inspection requirements in §60.5416a.

Table 26-2 Side-by-Side Comparison of §60.5416a and §60.5397a Closed Vent System and Cover Requirements

§60.5416a	§60.5416a Requirement	§60.5397a	§60.5397a Requirement
(a)	CVS and covers for compressors and pumps		
(1)	CVS Joints, seams and other connectors - Initial M21 and annual visual inspections.	(e) – (i)	All components – OGI monitoring initial and semi-annual
(2)	Other CVS components - Annual M21 and annual visual inspections		
(3)	Covers - Annual visual inspection		
(4)	Bypass	n/a	Not addressed in §60.5397a, but completely addressed in §60.5411a(a)(3)
(b)	M21	not needed	Not needed
(b)(1)-(8)	M21 requirements		
(b)(9)	Repairs - First attempt within 5 days, repair within 15 days.	(j)(1)	Repairs - Repair within 15 days.
(a)(1)(ii)	For CVS Joints, seams and other connectors only – monitor using M21 after repair/replacement	(j)(2)	Resurvey (all components) using OGI or M21 within 15 days of repair
(b)(10)	Delay of repair - If technically infeasible without shutdown – do at next shutdown	(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(b)(11)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(b)(12)	Difficult to inspect		
(b)(13)	Records	(k)	Records
(c)	Storage vessels		
(c)(1)	CVS - Monthly olfactory, visual, and auditory inspections for defects	(e) – (i)	All components – OGI monitoring initial and semi-annual
(c)(2)	Covers Monthly olfactory, visual, and auditory inspections for defects		
(c)(3)	Bypass	n/a	Not addressed in §60.5397a, but completed addressed in §60.5411a(b)(3)
(c)(4)	Repairs – Attempt first attempt within 5 days, repair within 30 days.	(j)	Repairs - Repair within 15 days. Resurvey using OGI or M21 within 15 days of repair
(c)(5)	Delay of repair (If technically infeasible without shutdown – do at next shutdown)	(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(c)(6)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(c)(7)	Difficult to inspect		

The related recommended rule changes throughout Subpart OOOOa to refer to §60.5397a rather than §60.5416a are provided in section 26.4.

26.3 The Requirements Do Not Need to Address Covers on Uncontrolled Storage Vessels and Covers and Closed Vent Systems on Storage Vessels Subject to Legally and Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under Subpart OOOOa.

Under the proposed scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled

storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief. Monitoring thief hatches can be complicated to determine the thief hatch is acting as pressure relief device or trying to distinguish the inherent leak rate of the device from a leak. Emissions from operation of a pressure relief device and the inherent leak rate would be considered process emission.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

26.4 Recommended Changes to NSPS Subpart OOOOa Related to Closed Vent System and Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout Subpart OOOOa refer to the fugitive monitoring and repair requirements in §60.5397a rather than the inspection, monitoring, and repair requirements in §60.5416a. Following are the specific suggested regulatory changes.

~~§60.5397a(j) For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (e)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers. You must comply with the requirements of paragraphs (j)(1) and (2) of this section.~~

~~§60.5410a(b)(4) You must conduct the initial inspections monitoring survey required in §60.5416a(a) and (b)§60.5397(j).~~

~~§60.5411a(a)(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b) complying with the requirements for fugitive emission components in §60.5397a.~~

~~§60.5415a(e)(3)(ii)(A) You must comply with §60.5416a(e) the requirements for fugitive emission components in §60.5397a for each cover and closed vent system.~~

~~§60.5420a(c)~~

~~(5)(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8), 60.5416a(e)(6)(ii), and 60.5416a(e)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.~~

(6) Records of each closed vent system ~~and cover inspection monitoring survey~~ required under ~~§60.5416a(a)(1) and (a)(2)~~ §60.5397a(f)(g),(h) or (i) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

~~(7) Reserved A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.~~

~~(8) Reserved If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.~~

(9) If you are subject to the closed vent system no detectable emissions requirements of ~~§60.5416a(b)~~ §60.5397a for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with ~~§60.5416a(b)~~ §60.5397a(k).

27.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

27.1 General

The following section addresses comments on EPA's proposed requirements for fugitive component emissions. Comments are organized around the following topics:

- Applicability
- Impacts, Emissions and Costs
- Work Practices and Inspections
- Testing and Monitoring
- Reporting and Recordkeeping.

27.2 Applicability Under §60.5365a(i)

27.2.1 The Definition Of Fugitive Emissions Component Is Confusing, Which Leads To Duplicative Affected Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 27.2.12).

Furthermore, the types of fugitive emissions components that EPA proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS VVa, KKK and GGGa. VVa defines equipment as “*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart*” (§60.481a). Under KKK, EPA defined equipment as “*each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart*” (§60.631). NSPS GGGa defines equipment as “*each valve, pump, pressure relief device,*

sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment” (§60.591a).

Since this proposal includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 15.0 Other equipment inappropriately included in this definition includes:

“access doors, ..., thief hatches or other openings on storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters.”

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches have complexities of operation and design as discussed in Section 26.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring in §60.5397a.

Vents are not fugitive components because they are designed to vent and compressors are covered separately in Subpart OOOO and OOOOa. Instruments and meters are not defined and some are designed to vent.

The following language in the definition should be removed as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

“Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.”

27.2.2 EPA Did Not Consider The Inconsistencies With State LDAR Programs (CO, PA, WY, TX, OH, Etc.). This Creates Duplicative And Potentially Conflicting Requirements With Little Environmental Benefit

Similar to the exemption for storage vessels under NSPS Subpart OOOO, §60.5365(e)(3), well sites or compressor stations subject to legally and practically enforceable requirements in an operating permit or other requirement established under Federal, state, local or tribal authority should be exempt from Subpart OOOOa LDAR requirements.

For example, the non-rule standard permit for oil and natural gas facilities in Texas²⁷ requires quarterly monitoring using M21 or optical imaging of valves and quarterly monitoring of pumps, compressor seals, and agitator seals without shaft sealing systems if the site fugitive emissions exceed 10 tons VOC/year.

²⁷ <http://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf>

However, proposed Subpart OOOOa requires OGI at least semiannually (and less frequently depending on percentage of leakers) for all components. Managing multiple LDAR programs for state and federal rules will create unnecessary compliance complexities for facilities trying to comply with the varying rules. Therefore, Subpart OOOOa should have allowances to rely on state LDAR programs in lieu of those in Subpart OOOOa if the state rules provide for equivalent work practices to reduce leak emissions.

The suggested exemption provided in the rule text edits at the end of this section (see Section 27.2.12) is consistent with the approach EPA used to quantify the cost effectiveness and the overall net benefits in the benefit-cost analysis for fugitives. Specifically, EPA excluded well sites in regulated states in their baseline and projections of affected oil and natural gas well sites in 2020 and 2025. The exclusion of well sites in regulated states has the effect of reducing both costs and emission reductions, so there is no net effect on cost effectiveness. However, the rule as proposed does not exclude well sites in regulated states from complying with OOOOa, which is not consistent with EPA's cost analysis. If well sites in regulated states are not exempt from Subpart OOOOa requirements, those affected well sites would incur higher costs to implement the additional LDAR requirements with little to no net emissions reductions. The resulting cost effectiveness would be higher than EPA estimated if those regulated well sites are not exempt. Therefore, EPA should exempt well sites subject to state LDAR requirements to be consistent with the approach used to estimate cost effectiveness. This will also prevent operators from having to develop a hybrid program based on the most stringent requirement between NSPS and state program requirements, which adds additional complexity to compliance.

In the Preamble, EPA requested comment on how to determine whether existing state requirements would demonstrate compliance with this federal rule. The table provided in Attachment F compares existing state LDAR requirements for Colorado, Pennsylvania, Wyoming, and Ohio to the proposed OOOOa requirements. Highlighted cells indicate where the proposed OOOOa requirements are more stringent than the state level requirements. API believes that any program (state, local, or even voluntary) that has the same conceptual elements (i.e. work practice standards for monitoring, recordkeeping and reporting) should be considered equivalent to OOOOa and therefore exempt from OOOOa LDAR requirements.

27.2.3 The 15 BOE Exemption In §60.5365a(i)(1) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden, But Is Not The Only Exemption To Consider

The 15 barrel of oil equivalent per day (BOE/day) exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions or for sites that are modified and pulled into the rule. It would however be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes in this proposal that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should be another threshold to exempt well sites from leak detection as well. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions

Rule text change recommendation to reflect these comments are provided in Section 27.2.12.

27.2.4 Fugitive Emissions Do Not Correlate To Production

The proposed rule provides a threshold for an affected facility under §60.5365a(i)(1) "A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil

equivalent (boe) per day averaged over the first 30 days of production, is not an affected facility under this subpart.” In the preamble, EPA solicited comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions, specifically on the relationship between production and fugitive emissions over time. EPA also solicited comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites, in addition to whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 BOE/day. As stated in our comment above (see 27.2.3), this exemption should also be considered as an off-ramp to §60.5397a applicability or exemption in the rare event of a modification to a stripper well. However, API believes it more appropriate and would prefer that the rule be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment. As indicated in sections 27.2.6 and 0, API believes that sites with equipment configurations or component counts less than the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

27.2.5 The Definition Of Well Site In §60.5430a Is Problematic And A New Definition For “Central Production Site” Is Needed

The proposed definition of “well site” includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The modification issue is discussed in more detail below in Section 0. The practical result of this error is that EPA's proposed definition of “well site” dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false regulatory construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption in paragraph (2) is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. The proposed definition change needs to be scrapped and either make no change to the original definition in Subpart OOOO or alternatively modify the definition as API recommends below in Section 27.2.12.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites

an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements in paragraphs §60.5365a(i) and (j). While the previous paragraphs discussed the issues with the definition of a “well site”, a new definition is needed to more accurately account for centralized sites. For paragraph (j) API recommends the term “central production site” and “transmission compressor station” replace the use of the single term “compressor station”. A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of in Section 27.2.12.

27.2.6 EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of “well site” and “fugitive emission component” could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 27.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

27.2.7 Only Sites With Major Equipment (Such As Separator, Heater, or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

§60.5365a(i)(2) exempts well sites that only contain one or more wellheads. “(2) *A well site that only contains one or more wellheads is not an affected facility under this subpart.*” API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the TSD are based on the following assumed equipment and component counts.

Table 27-1 EPA Model Well Site Equipment and Component Counts

	<i>Assumed Equipment Counts</i>		<i>Assumed Component Counts</i>	
Gas Well Sites	Wellheads	2	Valves	114
	Separators	2	Connectors	414
	In-line Heaters	1	OELs	14
	Dehydrators	1	PRVs	6
Oil Well Sites	Oil Wellheads	2	Valves	29
	Separators	1	Connectors	104
	Headers	1	OELs	1
	Heater/Treaters	1	PRVs	1

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. As discussed in Section 27.3.8, LDAR is not cost effective using the lower, unrounded estimates of component counts for the model well sites even without considering costs that EPA omitted from the cost effectiveness analyses. In addition, it is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

27.2.8 Based On EPA's Estimates, LDAR Requirements For Oil Well Sites Are Not Cost Effective. Therefore, Oil Wells Should Be Exempt From The Subpart OOOOa LDAR Requirements

Similar to the proposed low producing well site exemption for fugitives under Subpart OOOOa, oil well sites should be exempt from the LDAR requirements. This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

EPA's Levels of Reasonable Cost Effectiveness

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard to cost effectiveness, this proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of \$5,700 per ton.**" While EPA does not make an affirmation that is as clear-cut for methane, EPA's decisions establish a precedent. For quarterly OGI monitoring for well sites, EPA estimated the following cost effectiveness levels shown in Table 27-2.

Table 27-2 EPA's Estimated Cost Effectiveness With Savings (\$/ton) for Quarterly OGI Monitoring at Well Sites

Single Pollutant^a		Multipollutant^b	
Methane	VOC	Methane	VOC
\$3,521	\$12,668	\$1,761	\$6,334

^aTable 5-16 of the Background Technical Support Document.

^bTable 5-17 of the Background Technical Support Document.

For this option, EPA determined that “we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach.” (80 FR 53363). Therefore, since EPA rejected this alternative with a cost effectiveness of \$1,761 per ton of methane reduced, this clearly establishes that EPA believes that \$1,761/ton of methane is unreasonable.

EPA's Cost Effectiveness Analysis for Oil Wells

In the evaluation of the fugitive leak regulatory alternatives for well sites, EPA made their decisions based on the weighted average cost effectiveness of oil wells and gas wells. EPA clearly recognized the difference in emissions potential between oil and natural gas wells, as they developed different model plants. Yet, without any justification or rationale, they ignored these differences and lumped oil and natural gas wells into one category and decided that the costs were reasonable to regulate both. However, as shown in Table 27-3, there were significant differences in the cost effectiveness of OGI monitoring for oil and natural gas wells. EPA must re-evaluate the LDAR program options separately for oil wells and gas wells and make decisions on the reasonableness of the costs independently.

As is evident in Table 27-3, the cost effectiveness varies significantly between oil and natural gas wells. All the cost effectiveness values for gas wells, based on EPA cost estimates, are below the reasonableness thresholds discussed above (\$5,700/ton for VOC and \$1,761/ton for methane).

However, for oil wells, all the cost effectiveness values, with the exception of the methane cost effectiveness using the multipollutant approach, are above these thresholds. For the following reasons, EPA cannot conclude that OGI monitoring is cost effective and must not finalize any LDAR requirements for oil well sites.

Table 27-3 EPA's Estimated Cost Effectiveness - With Savings (\$/ton) for OGI Monitoring at Well Sites

Monitoring Period	Type of Well Site	Single Pollutant ^a		Multipollutant ^b	
		Methane	VOC	Methane	VOC
Semi-Annual	Gas	\$587	\$2,111	\$293	\$1,056
	Oil	\$3,186	\$11,460	\$1,593	\$5,730
	Weighted Average	\$2,536	\$9,124	\$1,268	\$4,562
Annual	Gas	\$500	\$1,799	\$250	\$900
	Oil	\$2,824	\$10,158	\$1,412	\$5,079
	Weighted Average	\$2,243	\$8,069	\$1,121	\$4,035

^aTables 5-15 (semiannual) and 5-14 (annual) of the Background Technical Support Document.

^bTable 5-18 (semiannual) and 5-17 (annual) of the Background Technical Support Document.

The Multipollutant Approach Is Not Legal. As discussed in section 10.0, EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own “rational basis” test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its “rational basis” test, the Agency must have a rational

basis for regulating *each* “pollutant.” See 80 Fed. Reg. at 56601. EPA’s multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple “pollutants” is reasonable where regulation of each pollutant individually would not be. Clearly the single pollutant cost effectiveness values are well beyond the levels EPA has determined to be unreasonable. However, even if EPA continues to consider this multipollutant approach, the points below demonstrate that LDAR at oil well sites is not cost effective under this illegal approach. Additional discussion of cost effectiveness is provided in Section 27.3, which expand further on costs that EPA did not even consider in their analyses.

Gas Streams at Oil Well Sites Have Lower Methane Content than the Representative Composition Used by EPA in Their Analysis.

All of EPA’s impacts analyses were conducted using a single representative gas composition.²⁸ For oil and natural gas production, this gas composition included 82.9% methane by volume. This methane content is relatively representative of the gas composition at gas well sites, but considerably higher than is present at oil well sites. In the same memorandum cited above, EPA also developed gas compositions for completions and recompletions at gas and oil wells. For oil wells, this composition included a methane content of 46.7% by volume. However, EPA elected not to use this composition in their analysis to evaluate the reasonableness of the costs of a program to reduce fugitive emissions from oil wells. Had EPA used this more appropriate gas composition, the lower methane content would result in lower methane emissions and lower methane emissions reductions. Using these these lower reductions would result in higher cost effectiveness values. For example, revising EPA’s analysis for oil well sites to utilize a methane content of 46.7% by volume would result in methane cost effectiveness values of approximately:

- Single pollutant cost effectiveness values for methane of \$5,656/ton and \$5,013/ton for semiannual and annual OGI monitoring, respectively.
- Multipollutant cost effectiveness values for methane of \$2,828/ton and \$2,507/ton for semiannual and annual OGI monitoring, respectively.

This realistic adjustment moves these cost effectiveness values, including those determined based on the multipollutant approach, to well above the \$1,791/ton level that EPA determined was unreasonable in this rulemaking.

EPA Significantly Underestimated the Costs of an OGI Monitoring Program. As discussed at length in Section 27.3, EPA’s cost analysis for an OGI monitoring program failed to consider many items that will significantly increase the cost. Table 27-5 provides a detailed item by item estimate of an annual OGI monitoring program based on API member companies that have actually implemented such programs. This analysis estimates the cost of an annual OGI monitoring program to be \$8,343 per year. This is almost seven times higher than the \$1,228 annual costs (with savings) estimated by EPA for an annual program. Even if EPA does not agree with all the adjustments to the cost estimate recommended by API, it is certain that the actual costs of a program would increase the small amount necessary to drive the multipollutant cost effectiveness for methane to greater than \$1,761/ton.

EPA’s Benefits Analysis

In addition, the benefit-cost analyses performed by EPA also support the conclusion that oil well sites should be exempt. The benefit-cost analysis is an assessment of the overall impacts of the rule, taking into account the economic impact analysis and an analysis of the climate, health, and welfare impacts from the proposed rule. EPA projects both the total costs and total benefits (for methane, the benefits are

²⁸ Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

associated with the avoided social cost of methane) for the first year the full rule is in effect (2020) and a later date to demonstrate how affected sources accumulate over time (2025). The net benefits for the target future dates represent the difference between the total benefits and costs.

Based on EPA's estimate of net benefits, even without considering unaccounted for cost elements (see Section 27.3.3) or the lower methane emissions (see discussion above), the benefit-cost analysis demonstrates that the net benefit is negative for 2020 and 2025 for oil well sites. The net benefits, based on EPA's analysis, are summarized below in Table 27-4 for oil well site LDAR requirements for 2020 and 2025. A negative net benefit means that the overall costs to industry for implementing the LDAR requirements for oil well sites is higher than the overall societal benefits from the emission reductions of methane. Therefore, the proposed LDAR requirements for oil well sites are not justified from an economic standpoint, and the burden to the industry is greater than the benefits accrued.

Table 27-4 Summary of EPA Cost Benefit Analysis for Oil Wells

<i>EPA Estimates for Oil Well Sites</i>	2020	2025
Benefits, \$MM	\$7.3	\$51
Costs, \$MM	\$19.7	\$119
Net Benefits, \$MM	-\$12.4	-\$68

Conclusion and Recommendation

As demonstrated in the previous discussion in this section, the economics do not support the regulation of fugitive leaks at oil well sites. First, EPA cannot "hide" the unreasonable costs of an LDAR program for oil well sites by lumping them together with the impacts at gas well sites, where LDAR program appears to be cost effective. Even if EPA utilizes the multipollutant approach (which API maintains is not legal), very minor adjustments to EPA's analysis to more accurately represent oil well sites results in costs effectiveness levels for all metrics that are beyond the levels that EPA has determined in this rulemaking to be unreasonable.

Therefore, EPA must not finalize any LDAR requirements for oil well sites. In their analysis, EPA did not define the criteria they considered in developing model plants for an oil well site versus a gas well site. API believes that, for the purposes of the applicability of these fugitive leak components, the API gravity and gas-to-oil ratio (GOR) are characteristics that can be used to define these "oil" wells that must be exempted from these fugitive emissions LDAR requirements. API proposes that a well site that produces oil with either an API gravity less than 18° or a GOR less than 300 scf/bbl be exempted.

The recommended regulatory change to accomplish this necessary exemption is provided in Section 27.2.12.

27.2.9 Produced Water Injection Facilities Should be Exempt from the LDAR Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reason these facilities should not be included in the fugitive monitoring program:

They contain operations and activities associated with produced water delivery, storage, and injection.

These facilities are constructed to manage a producing field's water production.

Natural gas is not typically associated with these facilities.

There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled.

Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 27.2.12.

27.2.10 The Definition Of Modification For Leak Detection Under §60.5365a(i)(3) Is Flawed For Both Well Sites And Compressor Stations.

Well Site Modification

EPA has defined a modification for well site fugitives as follows in §60.5365a(i)(3)

“For purposes of §60.5397a, a “modification” to a well site occurs when:

- i. a new well is drilled at an existing well site;*
- ii. a well at an existing well site is hydraulically fractured; or*
- iii. a well at an existing well site is hydraulically refractured.”*

Increasing production by drilling a new well or hydraulically fracturing an existing well does not increase the probability of a leak from an individual component and no new components result from these activities, thus the potential emissions rate does not change. EPA appears to agree, as there is no demonstration in this proposal, the TSD, or RIA that shows increased fugitive emissions from higher pressures. EPA's estimate of emissions simply uses the accepted method of component count × AP-42 factor.

The increased emissions from hydraulic fracturing are accounted for in the requirements for control devices and closed vent systems for storage vessels. Potential changes in pressure from hydraulic fracturing would only be on the components for the well head because components from the well choke or separator help to regulate the line pressure to that of the gathering system. Furthermore, for safety reasons, the components at the well head and down the line are rated for higher pressures beyond what wells and gathering systems will operate, and an increase in the pressure alone would not inherently impact the emissions from those components.

Compressor Station Modification

EPA has defined “modification: for compressor stations in §60.5365a(j):

For purposes of § 60.5397a, a “modification” to a compressor station occurs when:
(1) A new compressor is constructed at an existing compressor station; or
(2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

Here, EPA presumes that the addition of a new compressor at an existing compressor station would automatically increase the compressor station's emission rate and meet the definition of “modification”. This is very often not the case – an operator may install a new compressor at an existing site to replace one or more existing compressors, which may even reduce emissions. In addition, an increase in

compression capacity does not necessarily include a commensurate throughput and potential fugitive emission rate increase, it may simply be added for redundancy to increase operating reliability of the station. Throughput increases can also occur without increasing the number of compressors, if increases remain below the capacity of currently installed compressors.

Complicating matters, “new” means construction commenced after the proposal date. In this case construction refers to manufactured date. Since “new” compressors aren’t new because of when they are installed but rather when they are manufactured, “new” compressors may be relocated to other sites when no longer needed at current sites to save incurring capital costs of purchasing a newly manufactured compressor. This may also be a “new” or existing rental compressor if not expected to be on location long enough to justify a purchase of a new or existing compressor. Consequently, if a capital expenditure occurs, it will generally only be when the “new” compressor is initially installed. Relocating a “new” compressor from one site to another is often an expense, but not a capital expenditure. Paragraph 60.5397a(j)(1) is then based on a flawed premise to presume that a site modification has occurred. The “new” compressor may already be subject to Subpart OOOOa requirements, but was installed without incurring a capital expenditure. Coupled with situations for adding compression that do not incur an emissions increase as described in the previous paragraph, no modification occurs, and it is inappropriate to presume otherwise.

Similarly, presuming a physical change that increases compression capacity increases emissions is also flawed. Increasing capacity doesn’t necessarily mean an increase in throughput or an emissions increase in fugitive emissions. Capacity of one compressor may be increased so that another compressor can be permanently shutdown or relocated as part of a site optimization project which generally results in emissions decreases. In this case, a disincentive is presented in Subpart OOOOa by requiring a leak detection program for a project designed to decrease emissions, not increase.

Use of Modification in Other Rules

As with NSPS OOOO and NSPS KKK, it has historically been and should continue to be EPA’s intent that triggering NSPS through “modification” is in fact a difficult threshold to meet, not an easy one. Here, however, EPA’s proposed definition is overly inclusive and inappropriately relaxes the definition of modification.

The Clean Air Act Section 111(a)(4) defines a modification as follows - “The term ‘modification’ means any physical change in, or change in the method of operation of, a stationary source which **increases the amount of any air pollutant emitted** by such source or which **results in the emission of any air pollutant not previously emitted.**” [emphasis added]

Also §60.2 defines modification as: “Modification means any physical change in, or change in the method of operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.”

The original definition of modification in §60.14 includes an increase in hourly emission rates. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.”

§60.14 require three important elements before an event qualifies as a “modification”:

- (1) a physical or operation change to an existing affected facility,
- (2) that results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies, and
- (3) for which a capital expenditure is required.

These elements establish the very high threshold necessary to demonstrate a modification has occurred, whereas EPA’s proposal undermines these long-standing principles.

§60.14(e)(2) states that “an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility” is not a modification. EPA has defined in this rule the affected facility as a “well site” and the definition of a “well site” does not include the well bore or reservoir that is being fractured. “Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at §60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).”

Hydraulic fracturing is not a capital expenditure for the well site as it does not involve physical changes or changes to the operation of existing surface equipment. It is the process of “fracturing” the reservoir. A new well bore is subsurface and not part of the “well site” which is a surface site. Therefore, EPA should not consider the addition of a new well or hydraulically fracturing an existing well a modification for a facility for the purposes of LDAR.

Furthermore, other NSPS for fugitives (e.g., VVa and GGGa) define the affected facility by the process unit and requires a capital expenditure to be a modification to the process unit. VVa defines the affected facility as “the group of all equipment within a process unit” (§60.480a(a)). Equipment is defined as “each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart (§60.481a).” VVa also states that “Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.” VVa defines capital expenditure differently too giving a much higher B value of 12.5 vs. 4.5.

GGGa defines the affected facility as (§60.590a(a)):

- (1) The provisions of this subpart apply to affected facilities in petroleum refineries.
- (2) A compressor is an affected facility.
- (3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility.

Under GGGa, equipment is defined as “Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.” (§60.591a) Process Unit is defined as “the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.” (§60.591a) It states that “Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.”

Recommendation

EPA's cost analysis was based on a model plant with certain component counts (554 for gas wells and 135 for oil wells). API recommends that the definition of modification be based on the addition of certain large equipment such as a separator, heater, or dehydrator, as used for the model plant count basis, to be consistent with the basis of the cost analysis and other fugitive rules. Furthermore, replacement of

existing equipment should not be considered a modification to the facility since it would not increase the component count which is what the cost estimate is based on.

27.2.11 Components at Enhanced Oil Recovery Fields Must Be Exempted from the Fugitive Emissions Standards in Subpart OOOOa

Background on Enhanced Oil Recovery

Crude oil development and production in U.S. oil reservoirs can include up to three distinct phases of recovery: primary, secondary, and tertiary recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. Secondary and tertiary recovery techniques, which are often referred to as Enhanced Oil Recovery, or EOR, extend a field's productive life generally by injecting water, gas, heat, or chemicals to displace oil and drive it to a production wellbore.

Examples of secondary EOR techniques includes water floods, and tertiary EOR techniques includes thermal recovery floods (e.g., steam), and gas injection floods (e.g., CO₂). These EOR oil recovery techniques are used in oil fields to improve oil recovery after reservoir gas has been produced, and reservoir pressure and primary oil production are very low (e.g., no reservoir energy). In addition, the reservoir gas is artificially or mechanically changed with inert gases. Inert gases include nitrogen, hydrogen sulfide (H₂S), and carbon dioxide (CO₂). These inert gases may be required to be gathered and processed through specialty gas plants prior to sale. EOR is commonly found in older oil fields.

Water flooding is used to increase oil production by injecting a substantial amount of water into the oil reservoir rock voidage and increasing reservoir pressure. The injected water displaces the oil and carries the fluids to production wells. Water to oil ratios can be greater than 90%. In some EOR water floods, H₂S and other inert gases are generated in the reservoir. As a result, surface production equipment (i.e., plant) must be designed to handle high volumes of water and 3-phase fluids, and contain the potential "sour" and inert/contaminated gases for personnel safety reasons.

Thermal flooding is used to improve heavy oil recovery by injecting steam into the oil reservoir. Heavy oil has low viscosity, gas to oil ratio (GOR), and typically an API Gravity <18. The steam increases the heavy oil temperature reducing the viscosity allowing the oil to be produced from the well via artificial lift. The thermal surface equipment is designed to manage high volumes of water, heat the water, inject the steam, produce the hot oil, generally 2-phase separation of the fluids, and contain the low volumes of potential "sour" and contaminated gases for personnel safety reasons. Steam floods can generate substantial concentrations of hydrogen sulfide.

Gas injection (CO₂) flooding is used to improve oil recovery by injecting a miscible gas and water into the oil reservoir. The miscible gas, water, and increased reservoir pressure improves oil recovery and fluid sweep. Gas and water are injected into wells and the oil, water, and contaminated inert gas is recovered from production wells. The surface equipment is designed to manage high volumes of water, high pressure gas (e.g., CO₂ as a liquid), injection system, production/gathering system for the multi-phase liquids, high and low pressure separation of the fluids, and greater than 30% inert and potential "sour" gases. Due to the displacement characteristics of CO₂ and Immediately Dangerous to Life or Health (IDLH) for H₂S, the surface equipment is designed for personnel and public safety reasons.

EOR Gas Gathering Systems and Plants are designed to transport and process the volumes and EOR recovered gases that include CO₂, N₂ and H₂S.

EPA Did Not Consider EOR Operations in Their Rulemaking

Oil production fields that utilize EOR have very different gas stream compositions and characteristics from the types of operations that EPA evaluated in the development of the proposed NSPS subpart OOOOa (and the CTG). These differences have a significant impact on the VOC and methane emissions. EPA's model plants and representative gas compositions used to evaluate the impacts that drove the

regulatory decisions are derived from gas fields and natural gas processing plants, and they do represent EOR operations. For example, EPA used a single nationwide gas composition to estimate fugitive emissions from all sources.²⁹ This gas composition includes 3.2% inerts by volume. In the limited time available during the public comment period, API did a very brief survey of member companies and found that the inert content of the gas streams in EOR fields ranged from 14% to over 64% by volume, depending on the type of EOR technique used. Obviously this significant difference in gas composition will have a tremendous impact on the baseline VOC and methane emissions and the emission reductions achieved by the fugitive emission requirements. And without a doubt, the decisions made by EPA regarding the reasonableness of the cost in relation to the VOC and methane emission reductions would not be applicable to EOR fields.

From a careful review of the background information for proposed NSPS subpart OOOOa, it appears that EPA did not consider EOR fields in any manner. A search of the September 18, 2015 preamble, the Background Technical Support Document, and the Regulatory Impact Assessment did not find a single mention of "enhanced oil recovery."

However, while EPA did not consider EOR operations in this rulemaking, clearly they are aware of these operations and the emissions. Subpart W of the GHG reporting program requires the reporting of GHG emissions from EOR operations and defines *enhanced oil recovery as follows*:

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Further, Subpart W requires reporting of GHG emissions from two specific EOR operations - EOR injection pump blowdown and EOR hydrocarbon liquids dissolved CO₂. Note that in both instances EPA only requires the reporting of CO₂, indicating EPA's expectation that little or no methane would be emitted. Therefore, not only was EPA aware of these EOR operations, EPA had available GHG data from the GHG reporting program that they could have utilized. But they chose to totally ignore this segment in the industry in all technical evaluations.

Conclusions and Recommendation

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.
- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for subpart OOOOa.
- These differences will have a significant impact on the VOC and methane baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the preamble or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

²⁹ Memorandum. Brown, Heather P, EC/R Incorporated to Moore, Bruce, EPA/OAQPS/SPPD. Composition of Natural Gas for use in the Oil and Gas Sector Rulemaking. July 28, 2011.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in NSPS subpart OOOOa. Recommended regulatory changes are provided in Section 27.2.12.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in NSPS subpart OOOOa without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

27.2.12 Recommended Rule Text and Definition Revisions Based on Comments in this Section

§60.5365a(i) Except as provided in § 60.5365a(i)(1) through (i)(~~25~~), the collection of fugitive emissions components at a **new, modified, or reconstructed** well site, as defined in § 60.5430a, is an affected facility.

1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production **or for any 12 consecutive month period after startup of production**, is not an affected facility under this subpart.

(2) **Any well site or process unit with a GOR less than 300 scf/bbl during the first 30 days of production or for any 1 year period after startup of production is not an affected facility.**

(3) **Any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system is not an affected facility.**

(4) **Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.**

(~~25~~) **A well site with one or more wellheads that does not ~~only contain~~ include installation of at least one of the following: a separator, heater, or glycol dehydrator ~~one or more wellheads~~ is not an affected facility under this subpart.**

(6) **A well site that produces oil with either an API gravity less than 18° or a GOR less than 300 scf/bbl is not an affected facility under this subpart**

(7) **An EOR wellsite is not an affected facility under this subpart**

(~~38~~) **For purposes of § 60.5397a, a “modification” to a well site occurs when an additional well head, separator, heater, or dehydrator is installed.**

(i) ~~A new well is drilled at an existing well site;~~

(ii) ~~A well at an existing well site is hydraulically fractured; or~~

(iii) ~~A well at an existing well site is hydraulically refractured.~~

§60.5365a(j) The collection of **new, modified, or reconstructed** fugitive emissions components at a **central production site or transmission compressor station site**, as defined in §60.5430a, is an affected facility. **The collection of fugitive emissions components at a compressor station or central production site in an EOR field is not an affected facility.**

(1) **Central production sites and transmission compressor station sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.**

(2) **For purposes of § 60.5397a, a “modification” to a compressor station **or central production site** occurs when:**

- (i) ~~An additional new, modified, or reconstructed~~ compressor is installed at an existing transmission compressor station or central production site ~~that results in an increase in emissions of a compressor station or central production site; or~~
- (ii) A physical change is made to an existing compressor at a transmission compressor station or central production site that increases the ~~compression capacity of emissions at~~ the transmission compressor station or central production site.
- (iii) An additional new, modified, or reconstructed separator, heater, or dehydrator is installed at a central production site.

§60.5430

~~Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir.~~

Recommended definition changes:

~~*Central production site* means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.~~

~~*Fugitive emissions component* means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas driven pneumatic controllers or natural gas driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

~~*Well site* means one or more contiguous areas surface sites that are directly constructed disturbed during for the drilling and subsequent operation of an oil or natural gas well, and any affected by production facilities directly associated with any oil well or natural gas well. or injection well located on a well pad. For the purposes of the fugitive emissions standards at §60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).~~

27.3 Impacts, Emissions, Costs

27.3.1 EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed

In its cost analysis for the proposed control strategy for fugitive emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- Conducting leak surveys
- Completing repairs, and
- Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- Training of personnel
- Travel time and costs
- Equipment maintenance (e.g. monitoring device calibration)

The following sections expand on each of these topics in more detail and API provides revised costs that are more representative of actual costs anticipated to comply with the proposed rule. Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of \$2,230 per well site to over \$6,400 per site. As such, the Well Site Program Weighted Average cost effectiveness values (under a Multi-pollutant Method) would increase significantly beyond the already marginal values of \$1,384/ton of methane and \$4,979 per ton of VOC.

When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC. This finding is based solely on corrected costs and does not reflect any changes to the assumed emission reductions, which API believes have been overstated as well. **[Emphasis added]**

At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources.

The exception to this is oil wells. As discussed above in section 27.2.8, there is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

27.3.2 EPA Underestimated The Costs Of The Leak Survey And Leak Repairs In The Cost-Effectiveness Evaluation

In the cost estimation for implementing the LDAR requirements under Subpart OOOOa, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey

conducted by a contractor for a single well per well site (\$600/single well battery³⁰) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site (\$600/single well battery) and lower than the value provided for a multiple well site (\$1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of \$720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

27.3.3 Many Additional Aspects Beyond The Cost Of The Actual Survey Are Not Considered By EPA And Should Be Included In Cost-Effectiveness Evaluation (E.G., Training, Monitoring Device Calibration, Travel Costs, Etc.)

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey, such as program design and set up. EPA's cost analysis also failed to consider costs associated with training, monitoring device calibration, data management, and transportation. These are significant costs and should be part of EPA's assessment of the costs of the proposed requirements.

API surveyed companies conducting voluntary LDAR programs and compared these costs to EPA's model well site costs for annual LDAR. EPA's well pad model plant costs for semi-annual OGI LDAR surveys. Using EPA's cost spreadsheet for OGI well pad costs posted to the docket,³¹ API added or updated costs based on company information. API's cost estimate used the same assumptions as EPA's where company data were not available. Key differences in the costs include the following:

- EPA included the cost of a M21 monitoring device (\$10,800), but excluded the cost of the data collection system. EPA's separate cost estimate for conducting M21 LDAR includes a cost of \$14,500 for a data system in conjunction with the M21 monitoring device. It is not clear why EPA excluded this cost from the OGI LDAR estimate.
- EPA's estimate for developing monitoring plans does not indicate if it is for the corporate level plan, site level plans, or both. EPA's estimate is approximately one-half the cost provided by companies with voluntary programs.
- EPA's estimate of recordkeeping costs does not account for the need to purchase or expand a data collection system to store all the information associated with an ongoing LDAR program. EPA also does not consider the need for a data analyst to manage the information.
- EPA's costs do not consider the purchase of OGI equipment (~\$100,000 per unit), annual calibration of each OGI unit, or the training required to operate each unit.
- EPA's costs do not consider travel to and from each site to conduct the semi-annual surveys and for additional travel to repair and resurvey components when the repair cannot be completed immediately following the survey.

³⁰ Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.

³¹ CTG_Section_9_OGI_Well_Pad_Model_Plant_Costs_7-7--2015.xlsx

- EPA assumed a cost of \$2.00 to resurvey repaired components. This cost implies the use of soap bubbles under Section 8.3.3 of M21 to determine if the leak has been repaired. However, as written under §60.5397a (j)(2)(ii)(A), the proposed rule does not specify that soap bubbles can be used to determine if a leak is repaired [§60.5397a (j)(2)(ii)(A) - *A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.*]. API's cost estimate for resurveying to determine if a leak is repaired is based on determining if the concentration is less than 500 ppm above background.

The following table compares cost information for semi-annual OGI LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs (\$1,590 based on API estimates compared to \$2,096 from EPA's estimate as shown in Table 24-6). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is almost three times higher than EPA's estimate.

Table 27-5 Comparison of Monitoring Costs – One Time Company Level Costs

Item	API Annual Total Cost (\$)	EPA Annual Cost (\$)	Comment
One-Time Company Level Costs			
Read rule and instructions	\$231.20	\$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	\$7,200.00	\$3,468.00	API members estimate \$7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	\$1,849.60	\$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	\$1,271.60	\$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	\$95,000	Excluded from EPA's analysis	API survey responses ranged from \$90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	\$225,000.00		API survey responses ranged from \$200K-250K
FLIR certification Training	\$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	\$10,800	\$10,800	EPA estimate includes cost of M21 monitoring device (\$10,800) but excludes the cost of the data collection system (\$14,500) that was assumed for M21
<i>First Year Total Hours and Cost per Company</i>	<i>\$343,352</i>	<i>\$17,620</i>	Sum of total company costs above
<i>First Year Total Hours and Cost per Well Site</i>	<i>\$15,607</i>	<i>\$801</i>	Assumes company owns 22 well sites

Table 27-6 Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost (\$/yr)	EPA Annual Cost (\$/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	\$2,000.00	Not included	API estimates for annual training ranged from \$1,000 to \$5,000. Conservatively assumed \$2,000/yr
Data Analyst	\$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	\$4,000.00	Not included	API estimates ranged from \$3,000 - \$5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	\$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
<i>Recurring Annual Costs per Company</i>	<i>\$50,000.00</i>	<i>Not Included</i>	Sum of recurring annual costs above
<i>Recurring Annual Costs per Well Site</i>	<i>\$2,272.73</i>	<i>Not Included</i>	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	\$63.05	\$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	\$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	\$462.40	\$1,200.00	EPA cost from CL Report (outside contractor, well pad, \$600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.
Repair Cost	\$597.48	\$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours * \$66.24/hr) and 1 fixed offline (1 * 4.0 hours * \$66.24/hr)
M21 Resurvey Costs	\$115.60	\$4.00	EPA's resurvey costs assume cost of \$2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	\$231.20	\$231.20	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
<i>Cost per Well Site (Well site level costs only)</i>	<i>\$1,590</i>	<i>\$2,096</i>	Sum of well site level annual costs
<i>Annual Cost per well site with Amortized Capital Cost</i>	<i>\$6,476</i>	<i>\$2,230</i>	Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest

27.3.4 EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

In the Preamble, EPA indicated they were co-proposing monitoring surveys on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Many third party LDAR companies exist that perform regulatory work for LDAR in downstream portions of the petrochemical industry. However, most API companies that have implemented voluntary LDAR programs have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff and required in many cases more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand once OOOOa is promulgated. EPA should provide an initial compliance period of 1 year after publication of the final rule in the Federal Register to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training.

As well, a backlog of sites constructed between the proposal date and 60 days after the promulgation date will exist that will take time to develop any required monitoring plans in the final rule, in addition to needing time to smoothly implement a monitoring program which includes procurement of crews, equipment, and training as described above.

API requests a one-year plus 60 days phase in period from the promulgation date for compliance with the LDAR requirements, as EPA provided under §60.5370 by setting the compliance date to the later of October 15, 2012 or startup, and in defining affected facilities under §60.5360 relative to August 23, 2011. In the Response to Comments for OOOO, EPA indicated that the one-year phase-in was necessary to provide time for operators to have time to establish the need for control devices, procure and install devices. For similar reasons, a one-year phase in should be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

27.3.5 EPA Did Not Consider Impacts Of Travel To/From Sites By Trained Personnel

Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR at all new or modified well sites or compressor stations. A company may have a third party group or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average annual transportation cost per basin is \$34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of \$21,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

27.3.6 Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed Subpart OOOOa requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is \$188,125 with a reoccurring average annual cost of \$39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at \$60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin.

27.3.7 EPA Significantly Underestimated The Costs Of Developing And Maintaining The Corporate And Site-Specific Monitoring Plans

§60.5420a lists the notification, reporting, and recordkeeping requirements under the proposed rule. §60.5397a(b) requires that companies develop both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements in §60.5397a(c) and (d).

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plan for every well subject to NSPS OOOOa, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of \$3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

API member companies estimate the cost for developing a corporate monitoring plan to be \$7,200, and the cost to develop each site-specific monitoring plans to be \$120. Annual recurring costs to keep the plans up to date are estimated to range from \$1,000 to \$3,000.

To count and tag components at a compressor station, costs approximately \$10,000. In a study performed by an API member company which compared three basic leak detection methods: Audio, Visual, and Olfactory (AVO), OGI, and M21. Because M21 was already being conducted, the additional cost of component counts was \$15 to \$58 per site. However, if done in conjunction with an OGI survey, the cost would be substantially higher. API members estimate a cost of \$120 per well site to develop an initial component count (excluding travel costs), and a recurring annual cost of \$60/site.

In addition, EPA provided no provision for an area-wide monitoring plan. §60.5397a(b) requires that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan under §60.5397a(c) is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

Technique for determining fugitive emissions.

- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.

- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment - Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.
- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in Section 27.3.11.

27.3.8 EPA Overstated The Baseline Emissions And Emission Reductions

As discussed above, EPA significantly underestimated the costs of the proposed LDAR requirements. To compound the problem, EPA overestimated the baseline emissions and emission reductions, which causes the cost effectiveness estimated by EPA to be lower than actual conditions.

One manner in which EPA overestimated the emissions is in their approach for estimating component counts for the model plant gas and oil well sites. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. The effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the baseline emissions as follows:

Gas well sites: Baseline emissions decrease from EPA's estimate of 4.54 tons CH₄/yr/well site to an unrounded estimate of 3.18 tons CH₄/yr/well site, or a 30% reduction in methane baseline emissions and corresponding emission reductions.

Oil well sites: Baseline emissions decreased from EPA's estimate of 1.09 tons CH₄/yr/well site to an unrounded estimate of 0.70 tons CH₄/yr/well site, or a 36% reduction in methane baseline emissions and corresponding emission reductions.

27.3.9 API Members Find That Recurring LDAR Has A Diminishing Return

EPA assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in the initial and final economic impacts analyses and has also solicited comment on the approach. There is confusion between rulemaking presented by USEPA and Colorado on the origin of the 40, 60, and 80 percent emission reduction assumptions for tank OVI monitoring. Neither agency clearly substantiates the basis of their assumptions. In addition, EPA unilaterally changed the data from Colorado without justification. EPA should be required to produce the basis for these assumptions for industry review.³²

Additionally, on page 56635 of the preamble, EPA solicited comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies. API members find that recurring LDAR has a diminishing return [currently semiannually in proposed §60.5397a(g)]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates, ranging from 0.18% to 0.84% leaks for annual LDAR.

Survey data provided to API by companies subject to Colorado Regulation 7 enabled a comparison of the percent of components leaking for different leak survey frequencies (first time, then quarterly or monthly advanced instrument monitoring mechanism (AIMM) surveys). Overall, the percentage of components leaking were less than 1% from the initial survey and then decreased with subsequent re-survey. In the first quarterly AIMM survey, on average 0.88% of components were found leaking. In the second quarterly survey, the percent of components counts leaking dropped to roughly half at 0.38%. The monthly AIMM survey showed the same trend, with the initial survey finding 0.70% components leaking and subsequent monthly surveys decreasing to 0.17% in the 5th month. **Note, that although the leak finds decreased with subsequent surveys, the cost of each survey remained the same.** The \$/ton control provided by the EPA does not reflect the dramatic decrease in the percentage of leaking components over time with subsequent surveys.

From a separate analysis, an annual voluntary OGI survey involving 3,300 wells and 63 compressor stations, showed a 25% leak reduction at production sites and a 35% leak reduction at compressor stations in year two of an annual monitoring program. Based on HiFlow emission measurements and the

³² Colorado references EPA has a source for their assumptions, while EPA has referenced Colorado's analysis for the basis of the proposed rule language in the preamble. Cost-Benefit Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulations No. 3 and 7 (February 7, 2014),

assumption that leaks would have emitted gas for 365 days, emission reductions per well in year one of the annual survey was 148 thousand cf or 449 scf/ well. In year 2 of the annual survey at production sites, there was a leak count reduction of 25% and a corresponding emission reduction of 25% compared to the initial survey year. For midstream compressor stations, the emission reduction volume was 204 thousand cf or 2.9 thousand cf/station in year one of the annual survey. In year 2 of the annual survey at compressor stations, there was a leak count reduction of 35% and an emission reduction of 55% compared to the initial survey year.

API recommends annual surveying with no performance based adjustment to the survey frequency.

27.3.10 Fugitive Program For Gross Emitters

On page 56637 of the preamble, EPA indicated that commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to “gross emitters”.

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. As indicated in Section 27.3.9, API data on the leaks identified from recurring LDAR surveys indicates that annual LDAR is sufficient for identifying and correcting the relatively few fugitive sources with very high emission rates.

27.3.11 Recommended Rule Text Revisions Based On Comments In This Section

§60.5397a(b) You must develop a corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section. ~~and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate wide and site specific plans.~~

§60.5397a(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

- (1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) through (i) of this section.
- (2) Technique for determining fugitive emissions.
- (3) Manufacturer and model number of fugitive emissions detection equipment to be used.
- (4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.
- (5) Procedures and timeframes for verifying fugitive emission component repairs.

- (6) Records that will be kept and the length of time records will be kept.
(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of $\leq 10,000$ ppm at a flow rate of ≥ 60 g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

~~(i)(iii)~~ Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

~~(ii)(iv)~~ Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

~~(iii)(v)~~ Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

~~(iv)(vi)~~ Training and experience needed prior to performing surveys.

~~(v)(vii)~~ Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

§60.5397a(d) ~~Reserved Your site specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.~~

~~(1) Deviations from your master plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.~~

§60.5397a(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a **transmission** compressor

station or central production site shall be conducted ~~at least semi~~annually after the initial survey. Consecutive ~~semi~~annual monitoring surveys shall be conducted at least 49 months apart.

API also recommends adding the following definition to §60.5430a:

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

27.4 Work Practices/Inspections

27.4.1 Requiring An Initial Survey Requirement Within 30 Days Of Completion Is Not Appropriate For A Number Of Reasons

§60.5397a(f)(1) You must conduct an initial monitoring survey within 30 days of the first well completion for each collection of fugitive emissions components at a new well site or upon the date the well site begins the production phase for other wells. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 30 days of the well site modification.

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 27.2.12.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to §60.5397a(f)(1), the central battery must be surveyed again a month after the initial survey because of the new well. This

time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 27.4.14).

27.4.2 Quarterly Monitoring for Super Emitters

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, EPA indicated that they are taking comment on requiring monitoring survey on a quarterly basis.

As indicated in Section 27.3.9, API finds that recurring LDAR has diminishing return.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)*³³ shows that 5,000 ppm leaks were detected with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72

³³ Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at <http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf>

FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of \$5,700 per ton.** In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach.”

27.4.3 API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components

EPA solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

API does not support the proposed metrics of one percent and three percent of components specified in §60.5397a(i) and (h), respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components. **Therefore, API recommends removing both paragraphs (h) and (i) in §60.5397a.**

To count and tag components at a compressor station, costs approximately \$10,000 and requires continual maintenance and management. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was \$15 to \$58 per well site. However, if done in conjunction with an OGI method, the cost would be higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of \$120 per well site to count components initially, with a recurring cost of \$60 per well site to validate and update the counts annually.

27.4.4 Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Equipment Count For Each Well Site In Order To Properly Document The Percent Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR 98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment which are combined with EPA assumptions on component counts per equipment.

See Section 27.3.9 regarding API's recommendation for annual monitoring.

27.4.5 Recognize That Subpart W Already Requires Annual Fugitives Reporting For Certain Compressor Stations That Exceed The 25,000 Metric Ton CO₂e Threshold, And Request Comments On The Overlap Of These Reporting Requirements

§60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging.
(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least 4 months apart.

For transmission compressor stations or storage stations that exceed the reporting threshold of 25,000 tonnes CO₂e, Subpart W requires annual leak detection surveys at natural gas transmission and storage stations using Optical Gas Imaging, M21, or Infrared laser beam illuminated instrument [as specified in 40 CFR 98.233(q)(1) and 98.234(a)]. Subpart OOOOa is imposing a different frequency (semi-annual), more limited detection methods (OGI only), different reporting requirements, and a separate monitoring program than Subpart W for new or modified compressors stations. This creates duplicative and conflicting requirements. Subpart OOOOa should not apply to compressor stations currently regulated under Subpart W.

27.4.6 API Opposes Performance-Based Frequency

EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based frequency that is currently specified in §60.5397a(h) and (i). Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in Section 27.3.9, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

27.4.7 API Suggests 30 Days An Appropriate Amount Of Time For Repair Of Sources Of Fugitive Emissions At Well Sites

EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team if authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However some leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Also, the availability of training LDAR staff to re-monitor and validate that the component is indeed repaired is another logistical reason that more time is needed. Thus, API requests that 30 days be provided to complete the repairs.

Proposed text revisions are provided in Section 27.4.14.

27.4.8 The Current Proposal Does Not Allow For Multiple Attempts To Repair Identified Leaks.

In the proposed regulation, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak. Proposed text revisions are provided in Section 27.4.14.

27.4.9 Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts.

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Reg 7 indicate that about 5% of identified leaks required a delay of repair.³⁴ Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost. Lost production from compressor shutdowns was not included in EPA's cost estimate.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the

³⁴ Colorado Air Quality Control Commission, Public meeting on October 15, 2015.

North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months for reasons other than technical feasibility and safety, such as availability of supplies, availability of custom parts and where shutdown emissions are larger than what would be reduced. Subpart §OOOOa should be less stringent than what is required under VVa. VVa under 60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair:

- §60.482-9a(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.*
- (b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.*
 - (c) Delay of repair for valves and connectors will be allowed if:*
 - (1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and*
 - (2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.*
 - (d) Delay of repair for pumps will be allowed if:*
 - (1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and*
 - (2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.*
 - (e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.*
 - (f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition."*

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Proposed text revisions are provided in Section 27.4.14.

27.4.10 Thresholds for M21 Leak Definition and Repair

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). In addition, EPA solicited comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

For leak repairs that are not repaired during the initial survey, Subpart OOOOa allows either an OGI or M21 test with a leak threshold of 500 ppm to confirm that it is repaired [§60.5397a(j)(2)(i) and (ii)]. If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. Even in OOOOa for a gas plant, all the components do not have to meet 500 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA-HQ-OAR-2010-0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found-leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak definition should be changed in proposed §60.5397a(j)(2)(ii) from 500 ppm to 10,000 ppm.

Proposed text revisions are provided in Section 27.4.14.

27.4.11 API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles for leak detection, which currently does not appear to be allowed per §60.5397a (j)(2)(i):

§60.5397a (j)(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either M21 or optical gas imaging within 15 days of finding such fugitive emissions.

(ii) Operators that use M21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(ii)(A) and (B).

(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.

(B) Operators must use the M21 monitoring requirements specified in paragraph §60.5401a(g).

(iii) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(iii)(A) and (B).

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (a).

27.4.12 Monitoring Each Fugitive Component for Emissions

§60.5397a(e) – EPA is requiring that “*Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.*” Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. . Here is an example of what the sites look like:

Figure 27-1 Picture of Equipment Building



API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components

Proposed text revisions are provided in Section 27.4.14.

27.4.13 Application of Fugitive Emission Requirements at Modified Sites

EPA requested comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well.

For well sites, it is more complicated and difficult to manage to do fragmented LDAR based on difference applicability and different frequencies. Similarly it is complicated and difficult to manage a partial LDAR applied to different equipment or components at a given site. If a company is going to conduct LDAR for a specific piece of equipment at a site, it is just as efficient to scan the entire site. API supports annual LDAR for all the equipment located at an applicable well site.

27.4.14 Recommended Text Revisions Related To Work Practices/Inspections

§60.5397a(e) Each monitoring survey shall observe each ~~piece of equipment with~~ fugitive emissions components for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within ~~30~~180 days of the first ~~date of production well completion~~ for each collection of fugitive emissions components at a new well site ~~or upon the date the well site begins the production phase for other wells~~. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within ~~30~~180 days of the well site modification.

§60.5397a(f)(2) You must conduct an initial monitoring survey within ~~30~~180 days of the startup of a new compressor station ~~or central production site~~ for each new collection of fugitive emissions components at the new compressor station ~~or central production site~~. For modified compressor stations ~~or central production sites~~, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station ~~or central production site~~ must be conducted within ~~30~~ 90 days of the modification. ~~For affected facility compressor station or central production sites constructed between Sept. 18, 2015 and 60 days after [final date of rule], initial surveys must be completed by [insert one year and 60 days after final rule promulgation]~~

§60.5397a(j)(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than ~~45~~30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe ~~to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

§60.5397a(j)(2)(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

27.5 Testing and Monitoring

27.5.1 Other Fugitive Emission Detection Technologies

EPA requested comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future.

In the preamble, EPA states:

“We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM-33 approaches (e.g., Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (e.g., Rebellion photonics), and Airborne Differential Absorption LiDAR (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or

whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.”

Ongoing Research and Development Activities

The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of Method 21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E). As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totalling some \$35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify - major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired.

ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera (\$90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to \$3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as \$1,000 per site.

EDF Methane “Detectors Challenge” (MDC). In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot purchases and testing at oil and gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a “smart” alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The “MDC program refers to cost as a critically important factor and EDF and its partners

sought out technologies that could reasonably be expected to be sold for roughly \$1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.

The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1." Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2" which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations

An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as "... an instrument that makes visible emissions that may otherwise be invisible to the naked eye." EPA's Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)³⁵ provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should write the rule to allow any new technology to be used that is equivalent to OGI or Method 21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA's current definition of OGI (i.e. "... an instrument that makes visible emissions that may otherwise be invisible to the naked eye."). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

27.5.2 The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21.

³⁵ Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at <http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf>

Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).

- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H₂S concentrations where AVO is more effective than M21. Sites with high levels H₂S should be allowed to use AVO or H₂S monitoring systems to identify leaks at well pads.

27.5.3 For Laser Technology, Etc., How Might Performance Requirements Be Characterized?

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since OOOOa does not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

27.5.4 A Streamlined Approval Process Is Needed For Adoption Of Alternative Technologies As They Are Developed, Shown To Be Effective And Become Commercially Available

EPA should build into its final rule an “on-ramp” that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined “fast-track” process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level “equivalency” should not be required as EPA has required for using OGI versus Method 21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow “equivalence test for approving alternative methods. Moreover, the stringency of the process and “equivalency” testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in 60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7³⁶ provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or Method 21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

27.5.5 Allowance Of EPA M21 As An Alternative to OGI

EPA solicited comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold

Proposed Subpart OOOOa implies that the initial leak surveys must be taken using an OGI [§60.5397a(c)(7)]. We recommend revising the rule to specifically state that OGI, Method 21, or an equivalent method may be used for both the initial survey [§60.5397a(c)(7)] and repair leak surveys [§60.5397a(j)(2)].

In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves Method 21 for repair confirmation and emissions quantification is not required under OOOOa. According to Section 8.3.3 of Method 21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under Method 21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

27.5.6 Proposed Text Revisions Related To Testing And Monitoring Requirements

§60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas

³⁶ <https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf>

imaging, methods listed under 60.5397a(h), or approved alternative detection device under paragraph (m) of this section.

§60.5397a(j)(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using ~~either Method 21 or optical gas imaging one of the methods specified in §60.5397a(h)~~ within 15 days of ~~finding such~~ repairing the fugitive emissions source.

Add new proposed §60.5397a(h) below and re-letter paragraphs (h) through (l) to (i) to (m) to accommodate this addition:

§60.5397a(h). The initial and subsequent monitoring surveys specified in paragraphs (f) and (g) of this section must be conducted using one of the following methods:

- (1) Optical gas imaging equipment.
- (2) Method 21 (including soap bubbles as specified in Method 21, Section 8.3.3).
- (3) A method that the company keeps records to demonstrate that is equivalent in detecting leaks to either of the methods specified in paragraphs (h)(1) or (h)(2) of this section.
- (4) Screening methods, including but not limited to Tunable Diode Laser Absorption Spectroscopy (TDLAS), Interference Polarization Spectrometer (IR-CIPS), or Differential Absorption Light Detection and Ranging (DIAL LiDAR) technology, that screen for no leaks. If these methods do not detect a leak, then that survey is considered to have identified no leaks. However, if a leak is identified by one of these screening methods, then a monitoring method specified in paragraph (h)(1), (h)(2), or (h)(3) of this section must be used to confirm the presence of the leak.

Add:

(m) Alternative detection devices that can meet the following criteria can be submitted for approval for use by the Administrator or delegated authority within 180 days of a complete submittal:

- (1) Occurs at least annually
- (2) Pinpoints the general location of the leak
- (3) Is capable of detecting the hydrocarbons found at the site
- (4) Testing and certification are repeatable
- (5) Information on the limitations, other applications, how the devices works, how it will be used, and the process for recordkeeping and training are provided.

27.6 Reporting and Recordkeeping

27.6.1 The Rule Should Not Require A Separate Report For Each Well Site

API interprets “each collection of fugitive emissions components” in §60.5397a(l) (provided below for reference) to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations and submit the combined reports in one annual report.

§60.5397a(l) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive

emissions components at a well site or collection of fugitive emissions at a compressor station may be included in a single annual report.

27.6.2 The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value

§60.5397a(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed per §60.5397a(k)(6)(ii), which is provided above for reference. However, under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the OOOOa LDAR requirements it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. The preamble states (80 FR 56615) that a photo of each component that is surveyed is not required, yet a single photo of the well site or compressor, which would meet the rule requirements, is not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

The OOOOa requirements indicate that a photograph must be taken of ‘each source of fugitive emissions’ - §60.5397a(k)(6)(ii)– which is an actual leak. The proposed regulatory language and preamble appear inconsistent. A photo of a survey being conducted does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator’s certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey.

In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally un-manned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey.

Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. **API requests that EPA remove the requirement to take a photograph.**

27.6.3 API Strongly Opposes Sending Digital Photographs And Logs To Permitting Agencies

EPA is seeking comment on page 56615 of the preamble “on whether these [digital photographs and logs] records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens.” API strongly opposes sending digital photographs and logs to the permitting agencies. EPA’s cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there are real security risks when putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with limited security.

27.6.4 Visual Inspections Are Part Of Regular Operational Activities And Should Not Be Required In A Formal Protocol

EPA is seeking comment on page 56612 of the preamble on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation. These types of observations are part of regular operational activities and should not be required in a formal protocol.

27.6.5 EPA Needs To Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

“XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

XVII.F.8.b. The date and site information for each inspection;

XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;

XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

XVII.F.8.e. The date the leak was repaired;

XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;

XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and

XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s).”

API request that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

“XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:
XVII.F.9.a. The number of facilities inspected;
XVII.F.9.b. The total number of inspections;
XVII.F.9.c. The total number of leaks identified, broken out by component type;
XVII.F.9.d. The total number of leaks repaired;
XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st;
and”

27.6.6 Recommended Text Revisions Associated With Reporting and Recordkeeping Requirements.

~~§60.5397a(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

§60.5420a(b)(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station or central production site for a corporation or area, the records of each monitoring survey conducted during the year:

- (i) The number of facilities inspected
- (ii) The total number of inspections
- (iii) The total number of leaks identified broken out by component type
- (iv) The total number of leaks repaired
- (v) The total number of leaks on the delay of repair list as of December 31st

- ~~(i) Date of the survey.~~
- ~~(ii) Beginning and end time of the survey.~~
- ~~(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~
- ~~(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(v) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section~~

~~(A) Location.~~

~~(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(C) The date of successful repair of the fugitive emissions component.~~

~~(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

§60.5420a(c)(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.

~~(i) The fugitive emissions-The corporate-wide or area-wide monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5397a(a).~~

~~(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.~~

~~(A) Date of the survey.~~

~~(B) Location of the survey~~

~~(C) A list of leaking components~~

~~(D) The date of the first attempt to repair and additional attempts to repair~~

~~(E) The date the leak was repaired~~

~~(F) The delay of repair list including the basis for placing leaks on the list~~

~~(G) The date the leak was remonitored to verify the effectiveness of the repair~~

~~(B) Beginning and end time of the survey.~~

~~(C) Name of operator(s) performing survey. You must note the training and experience of the operator.~~

~~(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~

~~(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section.~~

~~(1) Location.~~

~~(2) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was~~

~~taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

~~(3) The date of successful repair of the fugitive emission component.~~

~~(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

Attachment A

API's Recommended Rule Language

Throughout the comments API has provided recommended rule language to assist EPA in making the necessary corrections to respond to the issues raised. These changes have been provided in redline/strikeout format. A consolidated version of all regulatory changes is provided within this Attachment as reference. If there are any discrepancies in this consolidated summary and the markups shown in the comments, those provided in the comments should be taken as our preferred position. For each section of Subpart OOOOa where regulatory changes are suggested, the sections of this document where these recommendations originate are provided in [blocked parentheses].

40 CFR PART 98, Subpart OOOOa

§60.5363a [SEE SECTION 6.0]

§60.5363a Which pollutants are regulated by this Subpart?

- (a) The pollutants regulated by this Subpart are greenhouse gases. The greenhouse gas standard in this Subpart is in the form of a limitation on emission of methane.
- (b) *PSD and title V thresholds for greenhouse gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, § 51.166(b)(48).
- (2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in § 52.21(b)(49) of this chapter.
- (3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.
- (4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§60.5365a [SEE SECTIONS 20.0; 22.2.2; 22.2.3; 24.3.3; 24.4.1; 24.4.5; 25.1; 25.2; 27.2.12]

- (a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio less than 300 scf of gas per **stock tank** barrel of oil produced. **Wells that must use artificial lift equipment to flowback completion fluid are not well affected facilities.**

* * * * *

- (a)(5) **A well completion operation in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.**

- (b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. **A centrifugal compressor in compliance with a legally and practically enforceable requirement that requires at least a 95% reduction in VOC or methane emissions is not an affected facility.**

- (c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well

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site, is not an affected facility under this subpart. A reciprocating compressor in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in paragraph (e)(1) of this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(e)(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production (i.e., the date that the storage vessel is placed into service).

* * * * *

~~(4) For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids or is used to replace any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirements as before being removed from service, or applicable to the storage vessel affected facility being replaced, immediately upon startup, startup of production, or return to service. Each storage vessel that was constructed, reconstructed, or modified after September 18, 2015 that replaces an existing storage vessel shall determine applicability according to the provisions in (e)(4)(i) or (ii).~~

~~(i) If the storage vessel being replaced is a storage vessel affected facility, the new storage vessel is an affected facility.~~

~~(ii) If the storage vessel being replaced is not a storage vessel affected facility, applicability shall be determined in accordance with paragraph (e) and (e)(1) of this section.~~

~~(5) Each storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service in accordance with §60.5395a(c) that is put back into service shall determine applicability according to the provisions in (e)(5)(i) or (ii).~~

~~(i) If the storage vessel is reconnected to the original source of liquids, it is a storage vessel affected facility subject to the same requirements as before being removed from service.~~

~~(ii) If the storage vessel is put back into service and not reconnected to the original source of liquids, applicability shall be determined in accordance with paragraph (e)(4) of this section.~~

~~(6) For the purposes of this Subpart, after the initial applicability determination for a storage vessel has been conducted in accordance with the requirements of paragraph (e) and (e)(1), situations that increase the throughput of that storage vessel shall not be considered modifications and shall not require a new applicability determination.~~

* * * * *

~~(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump with an exhaust rate greater than 53,000 scf/yr or a natural gas-driven diaphragm pump and that operates more than 2,160 hours per year.~~

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(h)(2) *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump that meets the criteria in paragraphs (i) through (iii) and is not excluded by (iv).*

- (i) *The pump has an exhaust rate greater than 53,000 scf/yr and operates more than 2,160 hours per year.*
- (ii) *The pump has a control device owned and operated by the owner and operator of the pump is located on site. For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.*
- (iii) *The pump has not been demonstrated to be technically infeasible to control.*
- (iv) *A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.*

(i) Except as provided in §60.5365a(i)(1) through (i)(25), the collection of fugitive emissions components at a new, modified, or reconstructed well site, as defined in § 60.5430a, is an affected facility.

(1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production or for any 12 consecutive month period after startup of production, is not an affected facility under this subpart.

(2) Any well site or process unit with a GOR less than 300 during the first 30 days of production or for any 1 year period after startup of production is not an affected facility.

(3) Any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system is not an affected facility.

(4) Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(25) A well site with one or more wellheads that does not ~~only contain~~ include installation of at least one of the following: a separator, heater, or glycol dehydrator ~~one or more wellheads~~ is not an affected facility under this subpart.

(6) A well site that produces oil with either an API gravity less than 18° or a GOR less than 300 scf/bbl is not an affected facility under this subpart

(7) An EOR wellsite is not an affected facility under this subpart

(38) For purposes of § 60.5397a, a “modification” to a well site occurs when an additional well head, separator, heater, or dehydrator is installed.

~~(i) A new well is drilled at an existing well site;~~

~~(ii) A well at an existing well site is hydraulically fractured; or~~

~~(iii) A well at an existing well site is hydraulically refractured.~~

(j) The collection of new, modified, or reconstructed fugitive emissions components at a central production site or transmission compressor station site, as defined in §60.5430a, is an affected facility. The collection of fugitive emissions components at a compressor station or central production site in an EOR field is not an affected facility.

(1) Central production sites and transmission compressor station sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(2) For purposes of § 60.5397a, a “modification” to a compressor station or central production site occurs when:

(i) An additional new, modified, or reconstructed compressor is installed at an existing transmission compressor station or central production site that results in an increase in emissions of a compressor station or central production site

(ii) A physical change is made to an existing compressor at a transmission compressor station or central production site that increases the ~~compression capacity of emissions at~~ the transmission compressor station or central production site.

(iii) An additional new, modified, or reconstructed separator, heater, or dehydrator is installed at a central production site.

* * * * *

§60.5375a [SEE SECTIONS 22.2.4 AND 22.2.5]

(a)(1)(i): During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section. A separator is not required to be located onsite during the initial flowback stage. Once conditions allow for separation, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in the separation flowback stage.

* * * * *

(3) You must capture and direct recovered gas to a completion combustion device, except 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 or it is technically infeasible due to inert gas concentration.

* * * * *

f)(2) You must capture and direct recovered gas to a completion combustion device, except 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 or it is technically infeasible due to inert gas concentration.

§60.5385a [SEE SECTION 23.1]

(a)(3) Collect the emissions from the rod packing using a rod packing emissions collection system ~~which operates under negative pressure~~ and route the rod packing emissions to a process through a closed vent system...

§60.5393a [SEE SECTION 24.5.1]

~~-(a)(2): Each pneumatic pump affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).~~

* * * * *

~~-(b)(3) Each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).~~

§60.5395a [SEE SECTIONS 25.5 AND 25.6]

(a)(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section ~~within 30 days of the monthly determination if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.~~

~~(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.~~

~~(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.~~

(b) Control requirements. (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c), and you must route emissions to a control device that meets the conditions specified in §60.5412a(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process ~~that reduces VOC emissions by at least 95.0 percent.~~

* * * * *

§60.5397a [SEE SECTIONS 26.4; 27.3.11; 27.4.14; 27.5.6; 27.6.6]

(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or approved alternative detection device under paragraph (m) of this section.

* * * * *

(b) You must develop a corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section, ~~and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site specific plans.~~

(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) through (i) of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

~~(i) — Verification that your optical gas imaging equipment meets the specifications of paragraphs (e)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of $\leq 10,000$ ppm at a flow rate of ≥ 60 g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

~~(i)(iii)~~ Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

~~(ii)(iv)~~ Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

~~(iii)(v)~~ Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

~~(iv)(vi)~~ Training and experience needed prior to performing surveys.

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(v)(vii) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

~~(d) Reserved Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.~~

~~(1) Deviations from your master plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.~~

(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components s for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within ~~30~~180 days of the first date of ~~production the first well completion~~ for each collection of fugitive emissions components at a new well site ~~or upon the date the well site begins the production phase for other wells~~. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within ~~30~~180 days of the well site modification.

(2) You must conduct an initial monitoring survey within ~~30~~180 days of the startup of a new compressor station ~~or central production site~~ for each new collection of fugitive emissions components at the new compressor station ~~or central production site~~. For modified compressor stations ~~or central production site~~, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station must be conducted within ~~30~~ 90 days of the modification. ~~For affected facility sites constructed between Sept. 18, 2015 and 60 days after [final date of rule], initial surveys must be completed by [insert one year and 60 days after final rule promulgation]~~

(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a ~~transmission~~ compressor station ~~or central production site~~ shall be conducted ~~at least semi~~annually after the initial survey. Consecutive ~~semi~~-annual monitoring surveys shall be conducted at least ~~49~~ months apart.

~~(h) The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station. The initial and subsequent monitoring surveys specified in paragraphs (f) and (g) of this section must be conducted using one of the following methods:~~

~~(1) Optical gas imaging equipment.~~

~~(2) Method 21 (including soap bubbles or SNOOP as specified in Method 21, Section 8.3.3).~~

~~(3) A method that the company keeps records to demonstrate that is equivalent in detecting leaks to either of the methods specified in paragraphs (h)(1) or (h)(2) of this section.~~

~~(4) Screening methods, including but not limited to Tunable Diode Laser Absorption Spectroscopy (TDLAS), Interference Polarization Spectrometer (IR-CIPS), or Differential Absorption Light Detection and Ranging (DIAL LiDAR) technology, that screen for no leaks. If these methods do not detect a leak, then that survey is considered to have identified no leaks. However, if a leak is identified by one of these screening methods, then a monitoring method specified in paragraph (h)(1), (h)(2), or (h)(3) of this section must be used to confirm the presence of the leak.~~

~~(i) Reserved The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0~~

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~~percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.~~

~~(j) For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers. You must comply with the requirements of paragraphs (j)(1) and (2) of this section.~~

~~(j)(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 1530 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.~~

~~(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging one of the methods specified in §60.5397a(h) within 15 days of finding such repairing the fugitive emissions source.~~

* * * * *

~~(ii)(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 50010,000 ppm above background.~~

* * * * *

~~(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

* * * * *

~~(m) Alternative detection devices that can meet the criteria in §60.5397(m)(1) through (5) of this section can be submitted for approval for use by the Administrator or delegated authority. The alternative is considered approved and can be used for compliance with this subpart if there is no response from the Administrator or delegated authority within 180 days of a complete submittal::~~

~~(1) Occurs at least annually~~

~~(2) Pinpoints the general location of the leak~~

~~(3) Is capable of detecting the hydrocarbons found at the site~~

~~(4) Testing and certification are repeatable~~

~~(5) Information on the limitations, other applications, how the devices works, how it will be used, and the process for recordkeeping and training are provided.~~

§60.5401a [SEE SECTION 12.5.6]

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

§60.5410a [SEE SECTIONS 24.4.8; 24.5.1; 26.4]

(b)(4) You must conduct the initial ~~inspection~~ monitoring survey required in ~~§60.5416a(a) and (b)~~ §60.5397(j).

~~(e)(3) Reserved You own or operate a pneumatic pump affected facility located other than at a natural gas processing plant and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in 60.5420a(b)(8)(i).~~

~~(e)(4) Reserved You must tag each new pneumatic pump affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).~~

§60.5411a [SEE SECTIONS 14.3 AND 26.4]

(a)(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by ~~§60.5416a(b) complying with the requirements for fugitive emission components in §60.5397.~~

(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is ~~discovered~~ ~~activated~~ according to §60.5420a(c)(8).

* * * * *

(c)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is ~~discovered~~ ~~sounded~~ according to §60.5420a(c)(8).

§60.5412a [SEE SECTIONS 12.5.6; 12.6; AND 13.2]

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. ~~Control devices in compliance with the requirements in §63.771 of 40 CFR 63, Subpart HH are exempt from the requirements in this Subpart.~~

(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility or §60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a ~~combustion~~

control device model tested under §60.5413a(d), w except for flare which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

(1) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ except for flare must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through ~~(iviii)~~ of this section.

* * * * *

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(d) Each control device used to meet the emission reduction standard in §60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a combustion control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

(1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through ~~(DC)~~ of this section.

* * * * *

~~(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

~~(3) You must design and operate a flare in accordance with the requirements of §60.5413a.~~

~~(34)~~ You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5413a [SEE SECTIONS 12.5.6; 12.7; AND 13.2]

(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through ~~(75)~~ of this section.

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~

~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~

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(42) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.

(53) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.

(64) A performance test is waived in accordance with §60.8(b).

(75) A **combustion** control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b)(1)(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion control device total TOC concentration limit specified in §60.5412a(a)(1)(ii).

~~(b)(3)(iv) Reserved If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

* * * * *

(d)(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

§60.5415a [SEE SECTION 26.4]

(e)(3)(ii)(A) You must comply with ~~§60.5416a(e)~~ the requirements for fugitive emission components in §60.5397a for each cover and closed vent system.

§60.5416a [SEE SECTION 26.2.1]

Remove Section 60.5416a

§60.5417a [SEE SECTIONS 12.5.7 AND 13.2]

~~(b) Reserved You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~

~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~

~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~

* * * * *

(d)(1) (iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

(iv) ~~Reserved For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5°C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~

* * * * *

(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the ~~combustion~~ control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion ~~control~~ device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the ~~combustion~~ control device.

§60.5420a [SEE SECTIONS 24.4.8; 24.5.2; 26.4; 27.6.6]

(b)(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station or central production site for a corporation or area, the records of each monitoring survey conducted during the year:

- (vi) The number of facilities inspected
- (vii) The total number of inspections
- (viii) The total number of leaks identified broken out by component type
- (ix) The total number of leaks repaired
- (x) The total number of leaks on the delay of repair list as of December 31st

- (i) ~~— Date of the survey.~~
- (ii) ~~— Beginning and end time of the survey.~~
- (iii) ~~— Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~
- (iv) ~~— Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
- (v) ~~— Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
- (vi) ~~— Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section~~

(B) ~~Location.~~

(B) ~~One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~

(C) ~~The date of successful repair of the fugitive emissions component.~~

(D) ~~Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

* * * * *

(b)(8)(i): ~~Reserved In the initial annual report, a certification that there is no control device on site, if applicable.~~

* * * * *

~~(v) If complying with §60.5393a(b)(1) with a control device tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e), records specified in paragraphs (c)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

* * * * *

(c)(5)(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8), ~~60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii).~~ You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(6) Records of each closed vent system ~~and cover~~ inspection ~~monitoring survey~~ required under ~~§60.5416a(a)(1) and (a)(2)~~ §60.5397a(f)(g), (h) or (i) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) ~~Reserved A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.~~

(8) ~~Reserved If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.~~

(9) If you are subject to the closed vent system no detectable emissions requirements of ~~§60.5416a(b) §60.5397a~~ for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with ~~§60.5416a(b) §60.5397a(k).~~

* * * * *

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.

(ii) ~~The fugitive emissions The corporate-wide or area-wide monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5397a(a).~~

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.

(H) Date of the survey.

(I) Location of the survey

(J) A list of leaking components

(K) The date of the first attempt to repair and additional attempts to repair

(L) The date the leak was repaired

(M) The delay of repair list including the basis for placing leaks on the list

(N) The date the leak was remonitored to verify the effectiveness of the repair

~~(B) Beginning and end time of the survey.~~

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- ~~(C) Name of operator(s) performing survey. You must note the training and experience of the operator.~~
~~(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
~~(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
~~(F) Documentation of each fugitive emission, including the information specified in paragraphs (e)(15)(ii)(F)(1) through (2) of this section.~~
~~(1) Location.~~
~~(2) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.~~
~~(3) The date of successful repair of the fugitive emission component.~~
~~(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

§60.5420a(c)(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(1)(i) through (iv) of this section.

- (i) Records of the date, location and ~~manufacturer specifications~~ make and model for each pneumatic pump constructed, modified or reconstructed.
- (ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.
- ~~(iii) Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~
- (iv) ~~Except as specified in paragraph (e)(16)(iv)(G) of this section, records for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5393a(b)(1) for each pneumatic pump.~~
 - ~~(A) Make, model and serial number of purchased device.~~
 - ~~(B) Date of purchase.~~
 - ~~(C) Copy of purchase order.~~
 - ~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~
 - ~~(E) Inlet gas flow rate.~~
 - ~~(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (e)(16)(iv)(F)(1) through (4) of this section.~~
 - ~~(1) Records that the pilot flame is present at all times of operation.~~
 - ~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~
 - ~~(3) Records of the maintenance and repair log.~~
 - ~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

§60.5430a Definitions [SEE SECTIONS 13.1.2; 13.2; 22.1; 22.2.3; 24.4.3; 25.4; 26.1; 26.2; 27.2.12]

Artificial Lift Equipment means the use of mechanical pumps (e.g., rod pumps or electric submersible pumps) to flowback fluids from a well.

Capital expenditure:

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

~~“Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection.”~~

Closed-vent system means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and if necessary, flow inducing devices that transport gas or vapor from an emission point to one or more control devices. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the conveyance system **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

Control device means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this Subpart.

Combustion control device means a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.

Enclosed combustion control device means a combustion control device with an enclosure such that the flame is not an open flame.

Fuel gas means gases that are combusted to derive useful work or heat.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.~~

Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the **true** vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

“Maximum average daily throughput means the ~~earliest calculation of~~ daily average throughput during the 30-day PTE evaluation period ~~that represents steady-state conditions employing generally-accepted methods.~~”

Natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump means a natural gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A lean glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a stationary source under this rule if the stays in one location for more than 12 months (or full annual operating period of a seasonal source).

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

Well site means one or more ~~contiguous areas-surface sites~~ that are ~~directly constructed~~ ~~disturbed during~~ for the drilling and subsequent operation of ~~an oil or natural gas well, and any affected by~~ production facilities directly associated with any oil well or natural gas well. ~~or injection well located on a well pad. For the purposes of the fugitive emissions standards at §60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).~~

Tables to Subpart OOOO [SEE SECTION 12.5.7]

Table 3 to Subpart OOOOa of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

Attachment B

API's Comments on EPA's NSPS Electronic Reporting
Proposal



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EPA Desk Officer
Office of Information and Regulatory Affairs
Office of Management and Budget (OMB)
Attn: Desk Officer for EPA
725 17th Street NW
Washington DC 20503

Attention: Docket ID: EPA-HQ-OAR-2009-0174

Re: Environmental Protection Agency's (EPA's) "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards: Proposed Rule" 80 Fed. Reg. 15100 (March 20, 2015).

The American Petroleum Institute (API) submits the attached comments on the Environmental Protection Agency's (EPA's) "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards: Proposed Rule" published in the Federal Register on March 20, 2015 at 80 Fed. Reg. 15100.

The American Petroleum Institute ("API") represents over 650 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

API members are involved with all aspects of the oil and natural gas industry, including the production of chemicals. Member facilities will be directly impacted by the provisions of the current proposal because of the large number of part 60 standards applicable to member company facilities and the precedents being established for recordkeeping and reporting requirements in general.

This proposal suffers from a failure to address the realities of reporting using an inflexible and difficult to revise electronic system, the realities of the structure of EPA regulations and EPA's practice of referencing part 60 paragraphs and subparts, and the difficulties of integrating EPA's electronic reporting system into existing EPA, State and company reporting processes. Since it is proposed to make the use of electronic reporting mandatory, all reporting system operating issues become significant since they can result in non-compliances due to failures beyond the control of the facility. If the proposed electronic system has the benefits claimed in this proposal, it would be quickly and widely used if it were available as an alternative. For these reasons, **API asks that EPA make EPA's Compliance and Emissions Data Reporting Interface (CEDRI) system and Electronic Reporting Tool (ERT) allowed alternatives to submitting hardcopy or PDF reports, at least for several years, until all of the operability and integration issues can be resolved.**

We are particularly concerned about the following specifics of this proposal:

- The failure of this proposal to meet the legal and administrative requirements for 1) imposing a certification requirement on part 60 reports where such a requirement is not currently imposed, 2) imposing new requirements on who may certify that are not imposed by the part 60 subpart that contains the certification requirement, and 3) requiring registration of Preparers and Certifiers, when that is not required for written reports or by regulatory language.
- The plan to impose future compliance requirements through Internet announcements rather than Federal Register rulemaking or at least Federal Register notices. As exemplified by this proposal, adding electronic reporting requirements with compliance deadlines and, potentially, other new report content requirements requires notice and comment rulemaking. API believes the Administrative Procedures Act (APA) and the Clean Air Act (CAA) require that a Federal Register notice and the ability to comment be provided for 1) every change to the CEDRI system that imposes a new requirement that is not present in the subpart to which it will apply, including that a particular report must be submitted electronically after a certain date, and 2) for changes that impose new report content or administrative requirements (e.g., requiring report certification, requiring emission estimates) that are not already required by the underlying part 60

subpart. Federal Register notices would not be required if electronic reporting were established as an alternative to the existing reporting requirements.

- The failure to address the issues associated with part 60 subparts that are referenced from other regulations, Consent Decrees and permits. It is common for part 60 subparts or paragraphs from part 60 subparts to be made applicable by reference, but often with changes. Electronic reporting templates for a subpart should deal with all requirements imposed by that subpart including requirements it imposes through reference and electronic reporting; and use of those templates should not be required until the template for the directly applicable subpart is complete.
- The proposal to require electronic reporting for incomplete pieces of reports. This approach adds large burdens with no benefits for anyone. For instance, requiring electronic submission of performance test velocity measurements when the associated pollutant concentration and calculation method is not covered by the ERT or requiring one data set of many that must be included in a particular periodic report.
- The failure to provide a system to deal with future changes to part 60 subparts. The Compliance and Emissions Data Reporting Interface (CEDRI) and the Electronic Reporting Tool (ERT) templates must immediately incorporate any additional or changed subpart reporting requirements and delete any removed reporting requirements when a part 60 subpart is amended or the CEDRI and ERT templates must accept reports that contain any newly required additional information and omit any information that is no longer required.
- The failure to provide backup reporting provisions for instances in which the EPA system cannot be accessed or when it cannot or will not accept reports electronically on their due date.
- The failure 1) to provide adequate compliance time, 2) to provide for beta testing and user input of each template prior to requiring its use, and 3) to provide tools, such as a “sandbox,” to allow facilities to test their new or revised electronic data entry system off-line.

EPA claims on page 15115 of the proposal preamble that “this action does not impose any new information collection burden under the [Paperwork Reduction Act]” and claims on page 15116 that “electronic reporting would reduce costs associated with information collection and, thus, compliance costs in the long-term.” Both claims are false.

The proposal actually imposes significant additional recordkeeping and reporting burdens that, in some cases, have not been legally justified and certainly are not cost justified. The proposal will also require additional reports in almost every case, at least for the foreseeable future. It is also important to note that, despite the claims in the proposal, no burden reduction credits under the PRA are available for instituting electronic recordkeeping or reporting, since EPA claimed those credits in its 1999 burden reduction rulemaking¹. The fact, that electronic reporting is only now being instituted does not allow those burden reductions to be claimed again.

Significant additional information collection burdens will result from the following:

- The proposal will undo the many reporting efficiencies currently in place (e.g., combined reports and delegated reports) and thereby will greatly increase the number of individual reports that must be submitted by facilities. Every additional report carries a burden cost, even if it only contains information that was previously reported as part of another report.
- The proposal will not eliminate any written reports in the foreseeable future because the proposed systems only cover some of the information that is required in most reports, and, thus, the electronic reports will have to be supplemented by written or PDF submissions. As a result, this proposal will cause, at a minimum, two reports to be submitted where one has sufficed.
- Many additional reports (e.g., perhaps hundreds or thousands of additional reports under subpart OOOO) will be required where multiple CEDRI templates are provided for separate portions of a current report or where current reports must be subdivided because of the CEDRI requirement to report site by site.
- Given the differences between the EPA system and existing State systems and the piecemeal and incomplete condition that the EPA system will be in for many years, there is no valid basis for the assumption that a significant portion of States will be using the EPA system within three years. All burdens associated with electronic reporting and with additional reports that result from this proposal are new and additional, as are the substantial burdens associated with separating electronic submission information from current reports and reconfiguring the current written reports to only include the information not covered by the electronic system templates.

¹ See 64 Fed. Reg. 7458 (February 12, 1999)) where, among other steps electronic recordkeeping and reporting was specifically authorized.

- Because previous reports apparently cannot be simply updated for a current submittal under CEDRI, as is the current practice, many additional hours of burden will be incurred generating each electronic report than is currently required. Even if new systems are put in place by industry to automate data entry, the burdens associated with the development and upkeep of these systems are not reflected in the record. Experience with EPA's ERT system demonstrates unequivocally that use of an EPA electronic system is an additional step, performed after reports are independently developed.
- This proposal appears to eliminate currently allowed electronic recordkeeping unless electronic reporting is in use. Such a change will undo the 1999 burden reduction rulemaking and would impose infeasible and unimaginable burdens. No provision for adding back some of the 780,000 hours of burden reduced under the 1999 amendments for allowing electronic recordkeeping and reporting is included in the economic or burden estimates for this proposal. Nor are the additional burdens, costs and impacts of requiring paper records considered.
- The proposal does not account for the burdens associated with users maintaining computer expertise, knowledge of the CEDRI and ERT systems, and updating of facility reporting systems as the CEDRI and ERT systems are revised. It is notable that even the relatively mature and limited ERT system underwent six revisions within the last year, that this proposal and the CEDRI and ERT webpages contain computer jargon and information that is only understandable by specialists, and that it takes an 80 page manual to explain how to access and use the CEDRI system, in general.

API believes this proposal will significantly increase industry recordkeeping and reporting burdens and that EPA should take significant steps to minimize those impacts, including making electronic reporting an alternative until all of the bugs are worked out for each individual subpart and CEDRI template

Please contact me if you have any questions or if we can amplify on any of these comments. I can be reached at (202) 682-8319.

Sincerely,

/s/

Matthew Todd

API

Attachment

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American Petroleum Institute

**Comments on
EPA's "Electronic Reporting and Recordkeeping Requirements for New
Source Performance Standards: Proposed Rule"
80 Fed. Reg. 15100 (March 20, 2015)**

Docket: EPA-HQ-OAR-2009-0174

June 18, 2015

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I. Introduction

The U.S. Environmental Protection Agency (EPA) is proposing to revise the part 60 General Provisions (part 60 subpart A) and many individual part 60 subparts to require specified air emissions data reports (typically performance test reports and reports associated with continuous monitors) to be submitted electronically and to allow affected facilities to maintain electronic records of the data associated with these reports.

API members have operations ranging from very small, unmanned facilities, potentially subject to one or two part 60 subparts covered by this proposal (e.g., subparts JJJJ and OOOO) to very large refinery and petrochemical facilities that may be subject to a great many part 60 subparts covered by this proposal. In both types of facilities, overlaps among these subparts and with part 61 and 63 subparts and permit and Consent Decree conditions are prevalent and compound the difficulties of efficiently complying with the proposed part 60-specific requirements.

The proposed changes will result in overly burdensome requirements for these facilities, albeit for somewhat different reasons between small and large ones. API believes the current proposal has serious flaws and legal deficiencies that need to be addressed including 1) providing adequate time for efficient conversion to the new systems and for corrections to EPA's Compliance and Emissions Data Reporting Interface (CEDRI) or Electronic Reporting Tool (ERT) programs, 2) making the conversion efficient and effective by adjusting the electronic system and its implementation in several significant ways, 3) meeting legal and process requirements for imposing new part 60 requirements, and 4) providing clarity for both the regulated community and regulators. To that end, we recommend that electronic reporting be established as an alternative for an extended initial period and that each new CEDRI template be available as an alternative for an extended period until all issues with it are resolved. Beta testing and provisions for a test "sand box" would ease this process significantly. In a few cases, API recommends deferring finalizing some of the suggested revisions until inconsistencies between current rule requirements and the electronic system requirements or wasteful burden impacts due to incomplete electronic systems can be resolved.

The proposal indicates that legally required notice for future changes to the electronic reporting requirements (i.e., adding CEDRI templates) will not be provided. We believe that future changes must, at a minimum, be noticed through the Federal Register and that more substantive changes, including those that result in additional or revised certification requirements, require notice and comment rulemaking.

API also has requested, below, that the proposed regulatory language be addressed, to clarify where the new requirements do not apply (as outlined in the preamble) and to clarify that these requirements are not retroactive.

Finally, the proposal suggests that electronic records, as opposed to written records, are only allowed by part 60 if they are associated with electronic reports through the new EPA systems. That presumption is patently false since 1) EPA specifically allowed electronic records and reports under part 60 in a 1999 rulemaking, 2) most records are already maintained electronically, and 3) the implications of returning to written records have not been addressed. We, therefore, recommend in Comment XI that the discussion of electronic records be clarified in the preamble to the final revisions and that none of the proposed regulatory language dealing with electronic records be finalized.

For convenience, our specific proposals are indicated by underlining.

II. Electronic Submission Should be An Alternative to Hardcopy or PDF Submission of Compliance Reports until all the Operability and Coordination Issues with Electronic Reporting Are Resolved.

This proposal suffers from a failure to address the realities of reporting using an inflexible and difficult to revise electronic system, the realities of the structure of EPA regulations and their practice of referencing part 60 paragraphs and subparts, and integrating EPA's electronic reporting system into EPA, State and company reporting processes. Since it is proposed to make the use of electronic reporting mandatory, all reporting system operating issues become significant since they can result in non-compliances due to failures beyond the control of the facility. Thus, API asks that EPA make the CEDRI and ERT systems allowed alternatives to submitting hardcopy or PDF reports, at least until the operability and integration issues discussed in these comments and the comments of others can be resolved. Similarly, API requests that all new templates be available as alternatives until they are thoroughly tested and user concerns are addressed. Such an approach would allow thorough testing of the systems and templates by actual users and provide time for EPA to address the issues identified. Given the large number of subparts and reports covered by these new requirements and the vast differences between facilities, we do not believe that either we or EPA can prospectively identify the problems that will be discovered in actual practice.

III. No Legal Basis is Provided for the New Requirement that All Part 60 Reports be Certified or For Limiting Who May Certify.

Performance test reports and many other reports covered by this proposal do not have certification requirements in either part 60 subpart A² or the applicable subpart. However, this proposal indicates on page 15105 of the preamble and on the CEDRI webpage that the CEDRI system requires a preparer and a certifier and proposes to limit who may certify a report where a certification is required. For instance, CEDRI specifies that the certifier must be the “owner or operator” and cannot be a contractor. EPA must clarify and revise the CEDRI templates and instructions to only require a certifier where a subpart so requires and cannot put conditions on who can certify a submission beyond those in the applicable subpart.

The proposal preamble and the CEDRI webpage state that a certifier is needed to “sign a package using an electronic signature³” and that the signature is compliant with the requirements of the Cross-Media Electronic Reporting Rule (CROMERR) “for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document⁴”. It should be noted that the CROMERR only specifies how electronic signatures are validated but does not impose any signature requirement itself. However, the CEDRI system requires a certifier (i.e., electronic signature) even if the subpart requiring the report does not require one. Furthermore, where a certification is required by the part 60 subpart, the CEDRI requirements are different from those in the subpart. In particular, CEDRI goes beyond subpart A signature requirements for excess emission reports, the most common report type addressed in this rulemaking. If a report must be certified or signed by the owner or operator, the subpart requiring the report must impose that requirement after notice and comment rulemaking. Such a requirement cannot be imposed through the CEDRI system protocols.

If EPA intends to require certification for all part 60 reports, this proposal is inadequate to justify this change. The proposal provides no legal authority for this expansive new requirement, does not propose any regulatory language for the affected subparts, does not include the additional burdens in the required PRA analysis or the proposal cost and burden analyses, and only discusses the additional requirement incidentally, as a *fait accompli*, in the preamble and on the CEDRI webpage. To impose a certification requirement where it is not now required in subpart A or in a particular part 60 subpart, EPA must provide a supplemental proposal for comment and obtain approval of the additional paperwork burden under the PRA.

² Subpart A only requires a signature on excess emission reports.

³ 80 Fed. Reg. 15105 (March 20, 2015), center column

⁴ Ibid.

A certification requirement adds burden to each report. Additional burden will also be incurred to maintain certifying official registrations with CEDRI as individuals and responsibilities change. API estimates a certification requirement adds at least two hours to the burdens associated with each report.

IV. Clarification Is Needed on Preparer and Certifier Criterion, Where Certification is Required.

Because of the large number of reports that will require certification (even if the universe of reports requiring certification is not expanded), the limitations imposed by CEDRI on who may certify, and the pace at which responsible officials change, EPA should specifically provide for delegation of certification authority in regulatory language (presumably in subpart A).

Furthermore, only larger facilities have individuals present on site who would be considered to represent the owner or operator. In many case, particularly in petroleum industry upstream operations, an owner's representative is likely to be responsible for a great many "facilities" and may not be located at any of them.

Some facility environmental professionals are contract employees and, in some cases, are authorized by facilities to submit reports. There is no valid basis for them not being allowed to be Certifiers, if the owner or operator of a facility duly delegates that responsibility to them. Thus, API requests that the proposed prohibitions on contractors registering as a Certifier or Delegated Certifier be removed.

In some cases, reports are prepared by an owner or operator employee, and there is no reason that person may not both prepare and sign or certify a report. API recommends the definitions not suggest (and that CEDRI not require) that Preparers and Certifiers be separate individuals. Additionally, some reports cover multiple equipment types, and, thus, it may be most efficient for a facility to have different people involved in preparing a particular report. API recommends that the preparer definition not suggest (and the CEDRI system not prohibit) multiple preparers for a single report.

The CEDRI webpage (<http://www.epa.gov/ttn/chief/cedri/>) describes who may prepare and certify CEDRI reports, and API recommends modified versions of these descriptions be formalized in part 60 subpart A. In addition to clarity improvements, the Certifier description must be revised to only require certification where the subpart requires it and not add constraints beyond those in the applicable subpart (as discussed in the previous comment). Additionally, it should be clarified in these definitions that the preparer and certifier may be the same person. The definitions from the CEDRI webpage, with API's recommended modifications, are as follows:

1. **Preparer:** The Preparer is the person responsible for the preparation of reports for ~~signature and subsequent submission by an authorized representative of the facility. Contractors are permitted to register as a Preparer and may assemble submission packages, such as files generated by the ERT, for the Certifier's approval and signature.~~ A Preparer may ~~not~~ sign and submit a submission package if certification is not required or if they are also a certifier or delegated certifier. ~~The Preparer may only access packages which they have prepared.~~
2. **Certifier (Where required):** The Certifier is the duly authorized representative of the source ~~or more commonly referred to as the "owner" or "operator" of the facility as specified in the applicable subpart. The~~ Certifier is authorized to prepare a report package or modify the report package a Preparer has assembled, and sign and submit the package to CDX where a certification signature is required. ~~The Certifier may perform all the tasks the Preparer may perform, but also has submission signing authority. Contractors are prohibited from registering as a Certifier.~~
3. **Delegated Certifier:** ~~The~~ Delegated Certifier is a person granted authority by a registered Certifier to sign and submit packages on behalf of the Certifier. The Delegated Certifier is authorized to prepare a report package or modify the report package a Preparer has assembled, and sign and submit the package to CDX where a certification signature is required. ~~The Delegated Certifier may perform all the tasks the Preparer may perform, but also has submission signing authority. Contractors are prohibited from registering as a Delegated Certifier.~~

V. There is No Legal Basis or Justification for Requiring Preparers and Certifiers to Register.

Signature and certification requirements currently in part 60 (or even for Title V reports, which has the most stringent Certifier requirements) do not require EPA be given a list of allowed Preparers or Certifiers. Anyone can prepare a report today and, since it would be a violation to falsely certify a report where certification is required, appropriate certification is self-policing. No legal or administrative basis is provided in this proposal for requiring an advance listing and no burden and cost estimates are provided. API recommends that the requirement that Preparers and Certifiers pre-register be deleted. Alternately, a supplemental proposal must be provided explaining the legal and administrative basis for this new requirement and allowing for comment.

Given the large number of reports that will require Preparers and Certifiers to register, if the registration requirement is maintained, the extensive change management such a system will require will necessitate a high degree of efficiency in identifying Preparers, Certifiers and Delegated Certifiers. Identifying these individuals on a facility or subpart basis requires multiple entries and makes change management difficult and burdensome. Thus, Preparers and Certifiers should only have to register once and not be limited to particular facility or subpart submissions.

VI. Electronic Reporting for Periodic Reports Must Not be Required for a Subpart or Paragraphs Made Applicable through a Reference from Another Subpart, a Permit or a Consent Decree until the Template for the Applicable Subpart is Final.

Many rules, permits, and Consent Decrees impose part 60 requirements by reference. For instance, part 60 subparts GGG, KKK, and part 63 subpart CC all reference part 60 subpart VV or portions of subpart VV, and many refinery Consent Decrees impose subpart J requirements. However, most such references also modify some of the referenced subpart requirements, resulting in different periodic report content than the referenced subpart itself requires. In some cases, references are to individual paragraphs in a referenced subpart not to the entire subpart. In that case, report requirements can be particularly unclear. Thus, there is a major concern with imposing electronic reporting and the use of CEDRI templates for part 60 subparts whose applicability comes from being referenced from other rules or from consent decrees. A CEDRI template for a subpart that is referenced from other rules, a permit or a Consent Decree will likely be inconsistent with the requirements of the applicable subpart, because it will not reflect the revisions specified in that subpart, permit, or Consent Decree.

In developing the template for a particular subpart, EPA should incorporate any requirements derived from referenced subparts and how they are modified by the referencing subpart. Thus, API recommends that the proposed amendments be modified to only apply electronic reporting requirements where a final template is available for that particular subpart and that electronic reporting not be required for a subpart that was made applicable through a reference from another subpart, a permit or a Consent Decree.

VII. EPA Must Clarify How Referenced Subparts are to Be Handled if Template Applicability is not Limited as Recommended in Comment VI.

As discussed in Comment VI, it does not appear that the CEDRI system can accommodate reports from one subpart that are required by reference from another subpart because of the revisions/modifications to the referenced subpart imposed by the referencing subpart. It is also unclear how CEDRI will confirm compliance with an applicable subpart, if reports use a template for another, referenced subpart. For instance, it is unclear how compliance with part 63 subpart CC is to be demonstrated if one or more of the referenced subparts has imposed electronic reporting requirements and some subpart CC required reports are submitted via templates identified as being for other, referenced subparts. Thus, if our recommendation in Comment VI is not adopted, EPA must make clear how sources are to identify reports for part 60 subparts (and part 61 and 63 subparts in the future) that are filed to comply with referencing subpart, not to comply with the part 60 subpart. Will the templates incorporate a means for providing that information? Will the templates be clear how to handle revised requirements due to changes imposed by referencing subparts?

VIII. At Least Eighteen Months is Required for Initial Compliance When the Current Proposal Is Finalized.

1. Proposed §60.7(c) of subpart A and most of the proposed revisions to specific subparts only allows 90 days from publication of the final rule to start submitting electronic reports where CEDRI templates are already available.

EPA estimates in Table 4 of the preamble, that this proposal will initially impact over 19,000 reports. For the oil and gas industry alone, API believes many thousands of reports per year will ultimately be impacted and thus believes EPA's impact estimate is low. It is impossible in 90 days to get procedures in place, locate or generate needed software, and train personnel for revising such a large number of reports. In addition to the non-trivial effort needed to generate a new electronic report, XML programmers must be hired or reassigned, Preparers and Certifiers must be identified and registered⁵, new written reports must be developed for each individual part 60 subpart covering non-CEDRI content, and shared reports must be separated. Finally, permits⁶ and procedures must be revised. Significant time and burden will be required

⁵ In some cases, as discussed later in these comments, hundreds or thousands of additional registrations will be required because current reports will have to be divided into a great number of new reports to accommodate the structure of the electronic system.

⁶ While many of the proposed changes can be treated as minor modifications and thus use a streamlined permit modification procedure, that is not true for all permit programs or permit conditions. In fact, some permits actually specify that written

to accomplish the necessary revisions and train personnel while not interfering with ongoing recordkeeping and reporting.

There is no legal need to limit the initial electronic report compliance period to 90 days, since the current written reports provide all of the required information and will continue to be submitted until any electronic reporting begins. Thus, given 1) the large number of reports that must be simultaneously revised to fit the CEDRI and Emission Reporting Tool (ERT) frameworks at a very large number of facilities, 2) the required learning curve and training needs, 3) the large population of facilities and personnel that will be dealing with these systems for the first time, and 4) the issues identified elsewhere in this discussion, API believes that at least eighteen months must be provided for initial compliance.

2. Any new system, especially an electronic system, will have errors and/or lack of clarity that does not become apparent until the system is widely used, often in spite of good beta testing. During our recommended eighteen month initial compliance time, the majority of these issues will be identified and the Agency should plan to address them prior to the final compliance date. Other template and system inadequacies will come to light after the compliance period as the full myriad of report variants must be accommodated. Given the inefficiencies of not having a match between CEDRI elements and report content and the potential that CEDRI will not accept reports that do not match the templates, API recommends EPA establish a system for immediately addressing concerns reported by the regulated community.

3. The proposal could be interpreted not to allow use of the CEDRI or ERT systems prior to the 90 day compliance date proposed. In order to foster testing and to allow identification and addressing of problems prior to the compliance date, API also recommends the Agency accept a CEDRI template submittal during the initial compliance period.

IX. Semiannual Federal Register Notices and At Least 180 days are Needed to Allow for Compliance With Templates Added to the CEDRI System.

As described on page 15104 of the proposal preamble, "When CEDRI is updated to support electronic submittal of the required report, you would have 90 days from the date of the reporting form's availability in CEDRI to commence electronic reporting to the EPA." The only notice of the change would be through the CEDRI website, a website most owners and operators do not monitor regularly or should not be expected to look at routinely. Since adding a CEDRI template imposes a new enforceable requirement and a short compliance deadline, the Administrative Procedures Act (APA) as well as the Clean Air Act (CAA) requires official

reports must be submitted to EPA and those provisions must be changed before a source can replace those reports with electronic reports.

notice of the changes in the Federal Register and notice and comment rulemaking if the change imposes new report content or other new requirements (e.g., certification).

We discuss separately (see Comment X, following) where a full notice and comment rulemaking would be required for CEDRI and ERT changes. Furthermore, the proposed approach would seem to foreclose posting of draft templates for comment and testing, since the proposed language does not specify that the compliance time only applies when final, complete templates are posted. Thus, API recommends that the final rule language be clear that compliance is only required after a "final" template is posted to the CEDRI website.

Even if it has been beta tested, any new form or template will require shakedown and impacted facilities will have to make procedure revisions, undertake permitting activities, identify and register Preparers and Certifiers, and develop or revise computer programming to provide the required data in the required format. If this is the first rule with these requirements for a particular facility, the effort needed will be even more extensive. Experience with the Greenhouse Gas Reporting Rule shows that the proposed 90 days is woefully inadequate. Under that rule, a year was needed to finalize templates. If the part 60 templates are narrowly focused and do not impose changes to the reports already required by an individual subpart, API believes that 180 days, rather than one year, after a Federal Register notice is adequate to comply with such additions. If a template has not been through public review and beta testing, 180 days will be inadequate to identify and resolve template issues and at least eighteen months must be provided.

X. Notice and Comment Rulemaking is Required to Revise a Subpart Where Additional Reports, A New or Revised Report Certification, or Additional Report Content is Required as Part of the Change to Electronic Reporting.

The proposed amendments in this proposal identify specific reports or portions of reports (e.g., excess emission reports, RATA test reports) that are to be submitted through CEDRI (as CEDRI forms become available). For instance, most of the proposed amendments require periodic reports or the excess emission portion of the periodic report to be submitted through CEDRI. If, in the future, EPA desires to 1) have other reports (e.g., one time notices or the full periodic report) submitted, 2) to require report certification where such certification is not currently required by a particular subpart, or 3) to change the content of any required report, notice and comment rulemaking to amend the impacted subpart is required.

Similarly, as discussed in Comment XII, if the CEDRI structure requires information to be submitted piecemeal (see for example Comments XII through XIV below, versus a current periodic report, notice and comment rulemaking must be undertaken to authorize the change and the additional burdens. This proposal imposes many such requirements, but does not appear to have reflected the impacts, costs, and burdens for the additional reporting in the rulemaking record.

Furthermore, any information required by CEDRI (e.g., certain facility information, emission estimates) that is not specified as required content in a particular subpart is not legally required, and failure to submit that information would not be enforceable and cannot be a basis for the CEDRI system declining to accept a submission.

XI. EPA Is Incorrect That Most Records Required by Part 60 Are Currently Kept as Hardcopies, and EPA Should Not Finalize Any of the Proposed New Electronic Record Language.

On page 15107 of the preamble, it is stated: “Most of the NSPS require affected facilities to keep records, such as raw data and reports of emissions monitoring and testing, onsite. Many of the NSPS require that this information be maintained in hardcopy form.” On page 15108 of the preamble, it is also claimed “...we believe that electronic recordkeeping is an adequate method of record retention that will improve record accessibility and will provide reduced storage benefits to facilities, resulting in a cost savings for industry. The EPA specifically solicits comment on the proposed amendment to allow electronic recordkeeping in lieu of hardcopy records.” Furthermore, in many of the proposed subpart revisions, and especially in the proposed new §60.7(i), it is proposed to add language that specifically allows electronic records for information associated with CEDRI electronic submissions and, by inference, disallows it in all other cases.

The suggestion that written (i.e., hardcopy) records are required by part 60 is false⁷. For example, §60.7(b) of subpart A simply states the owner or operator shall maintain records without specifying in what form. Electronic records are now more common than paper records for all environmental recordkeeping, and part 60 rules do not distinguish how a record is maintained, but only address what records are required and how quickly they must be available. Part 60 currently allows records, including report copies, to be maintained electronically, as long as the data can be provided quickly onsite. Of most direct impact on the

⁷ While “written reports” are required in some cases (e.g., for performance tests), “written” records are almost never specified in part 60 (or part 61 or 63).

form of part 60 record requirements is §60.7(f), which deals with monitoring records and is not proposed for revision. It states:

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

...

This paragraph was added to §60.7 through amendment in 1999⁸ for the express purpose of allowing electronic recordkeeping and, in concert with the amendments of §§60.7(a) and (c), 60.8(d), 60.13(h), 60.19(b) and 61.04(b) in that same rulemaking, to achieve a claimed 780,000 hours of burden reduction through reduced periodic report frequency, electronic reporting and electronic recordkeeping. The criteria in §60.7(f) purposely does not require written records, since allowing electronic records and reports was the intended purpose of adding the paragraphs. In fact, these requirements are clearly distinguished from those where a written record is required, since, for instance, a “hard copy” of the data acquisition algorithm is specifically required in §60.7(f)(1).

⁸ See 64 Fed. Reg. 7458 (February 12, 1999)

Modern monitoring systems generate many data points per second. Neither the amount of paper nor storage space required for hard copies is available. Even if hardcopy storage were available, it would be impossible to retrieve information for a particular time period on a timely basis without searchable electronic databases.

The preamble discussions in the current proposal and the proposed addition of electronic recordkeeping paragraphs to subpart A and many part 60 subparts could be construed, despite §60.7(f), as requiring hardcopy records for any record not associated with a CEDRI submission and could be construed to apply retroactively. EPA has not presented an explanation for reversing its 1999 rulemaking and requiring written records, nor has it identified the impacts on forests, storage space, or burdens. Thus API recommends that none of the proposed language dealing with electronic records associated with electronic reports can be finalized, particularly proposed §60.7(i). Specifically the following proposed paragraphs or paragraph revisions dealing with records associated with electronic report submissions cannot be finalized based on the record provided: §§60.7(i), 60.59a(k), 60.59b(j), 60.76a(g), 60.107(h), 60.115b, 60.276(f), 60.276a(j), 60.287a(d), 60.315(d), 60.455(d), 60.465(d), 60.486a(1), 60.486a(a)(1), 60.495(d), 60.545(g), 60.565(o), 60.647(a), 60.697(a), 60.724(d), 60.735(a), 60.747(h), 60.758(g), 60.1385(c), and 60.5420(c).

XII. EPA Must Find Ways to Not Divide Up Current Reports into Multiple CEDRI Reports and Thereby Add Large and Unjustified Burdens.

Many periodic reports, particularly the reports required by some subparts that affect petroleum and natural gas upstream operations (e.g., part 60 subparts IIII, JJJJ and OOOO), allow a single report for many individual affected facility sites. Based on the proposal and the templates currently posted for subpart IIII and JJJJ, it appears the annual report information for these subparts must be separated into separate submissions because CEDRI requires site-by-site reports and individual templates only cover part of the required content for each engine. This separation will impose great inefficiency, since it will cause multiple data entries and certifications. For subpart OOOO, perhaps hundreds or thousands of reports will be required, where one suffices today. These large inefficiencies do not appear to be reflected in the proposal cost and burden analysis and certainly are not justified. API, therefore, recommends that CEDRI templates be exactly matched to current subpart reporting requirements and that any changes to the number of separate reports required because of the structure of CEDRI or the templates be made through notice and comment rulemaking that specifically addresses the requirement for additional reports and certifications. Further, any such change must be reflected in the specific subpart's report content language and PRA approval.

XIII. The Proposed Approach for Subpart OOOO is in Conflict with Subpart Requirements and Should be Revised and Amendment of Subpart OOOO Should Not Be Finalized at This Time.

Part 60 subpart OOOO applies to crude oil and natural gas production, transmission and distribution. It is proposed to require that the annual reports required by this subpart be submitted through CEDRI starting 90 days after a template is available. Because of the unique operations of this industrial category, we see several problems (beyond the cross-cutting ones discussed elsewhere in these comments) with applying CEDRI as proposed, and API requests that these concerns be resolved **before** these new requirements are finalized for subpart OOOO.

1. Under this proposal the subpart OOOO annual report required by §60.5420(b) must be submitted electronically once a template is available. Under subpart OOOO each regulated item is a separate affected facility; however, they are reported together in the annual report. The individual affected facilities are identified in the annual report in different ways (often by their latitude and longitude) but not necessarily by the site where they are located, since there often is no site address and the affected facility (e.g., well) may be the only thing at that location. That is why subpart OOOO does not require that all types of affected facilities be linked with a particular site (e.g., subpart OOOO requires wells and storage tanks be identified by their longitude and latitude).

As we understand it, the CEDRI system links reports to the site at which they are located. Identifying each site separately in CEDRI would require deconstruction of the annual report as currently specified in subpart OOOO (a change which was not proposed), imposing very large unjustified burdens that have not been considered and that are inconsistent with the promulgated reporting requirements of subpart OOOO. For instance, one member company reports they have approximately 8000 such sites and another member reports upwards of 20,000 sites. Although not all of the sites currently require reporting under subpart OOOO, there may be hundreds of thousands of sites in petroleum upstream operations as new wells are drilled and new equipment is added to existing sites. The CEDRI requirement to link every affected facility to a site could therefore require thousands of reports and responsible official certifications for each current subpart OOOO report. API, therefore, requests that the CEDRI system be modified to accept subpart OOOO annual reports as currently specified in §60.5420 of subpart OOOO and not require linking the reports to particular sites and that the proposed amendment of subpart OOOO not be finalized until those revisions are completed.

2. Subpart OOOO requires that the annual report be certified, as does the CEDRI system, however, subpart OOOO has a specific definition of “certifying official⁹” that is different from the definition on the CEDRI webpage (cited in Comment IV above), and API, therefore, requests that the final revision to subpart OOOO clarify that the certifying official for CEDRI reports is the one defined in §60.6430 of subpart OOOO. Furthermore, consistent with Item 1 of this comment, no more certifications can be required than are currently required by subpart OOOO, without notice and comment rulemaking that addresses this specific issue.

XIV. Engine Reporting Requirements Under Subparts IIII and JJJJ Need Improvement, the Small Business Implications of the Subpart JJJJ Performance Test Reporting Requirements Must Be Addressed, and The Proposed Requirement to Use the ERT System Should Not Be Finalized at This Time.

There are three specific issues that need to be addressed.

1. It is proposed to revise subpart JJJJ to require submitting performance test reports through the ERT system. However, that subpart includes specific equations for calculating engine emissions and specifies several alternative test methods for each pollutant, most of which are not covered by the ERT. There is no benefit to requiring electronic submission of extremely partial data and that is clearly all that is possible for engine tests at this time. The only result of this requirement will be to generate electronic submissions that serve no purpose and are never used, since only the written or PDF submission will contain adequate data for evaluating the performance test. For an ERT submission to be useful and for us to be able to evaluate the proposal to require it, all of the method options and the templates for applying the §60.4244

⁹ *Certifying official* means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

equations must be available. API, therefore, recommends the proposal to amend §60.4245(d) and the applicability of proposed §60.8(j) be deferred until the entire potentially applicable ERT and CEDRI templates are available.

2. Engines subject to subpart IIII and JJJJ change locations and owners frequently. Thus, they cannot be readily identified or tracked by linking them to a particular site as the ERT/CEDRI system seems to require. Thus, the ERT/CEDRI system for engines needs to be modified to identify the engine by only the information specified in subpart JJJJ (i.e., its make, model, engine family, serial number, model year and, by the latitude and longitude of its location at the time of the performance test.

Since engines often change locations and owners it would be difficult using a facility based electronic system to assure all required reports for a particular engine have been submitted, since the engine may be at different facilities at different reporting times and thus covered by different annual reports. Inability to match engines to reports would likely lead to difficulties for inspectors in assuring compliance and for owners and operators because of the effort they would have to expend responding to claims that they failed to file reports for engines that they no longer owned or operated. EPA should propose a system that allows tracking of engines by their identifying information, rather than by site. That proposal should also include realistic burden estimates and justifications and provide a simple and efficient mechanism for handling relocation and changes in ownership that does not impose undue burdens on engine owners and operators.

3. There are thousands of engines in petroleum and natural gas upstream operations, and, thus, hundreds to thousands of performance tests per year will ultimately require reporting. Most engine testing is performed by small companies that are not likely to have or to be able to afford the computer expertise needed to report through the ERT/CEDRI system. Thus, this particular portion of the proposal may have a significant deleterious impact on these small businesses. EPA must evaluate the impact of this proposal on these small entities and, if significant, formally evaluate these requirements under the Regulatory Flexibility Act and obtain review by the Small Business Administration.

XV. Prior to Finalizing this Proposal, EPA Must Make the CEDRI System as User Friendly as Possible, Beta Test Individual Subpart Templates, Provide a Test Sandbox and Provide Training for Those Potentially Impacted.

On page 15111 of the proposal preamble, EPA acknowledges that “there is a learning curve associated with the use of our electronic system and data need to be entered initially which will be automatically populated in future reports.” However, EPA is unreasonably optimistic about this learning curve.

Examples of the problems likely to occur with the CEDRI system include the following:

- The XML templates already in the system are not user-friendly, and it is unclear how to populate and use them. For example, some of the environmental professionals responsible for reporting under subpart JJJJ indicate that the CEDRI template is unclear to them and the guidance document only contains two pages that discuss the three currently available templates and provides no real help. One-to-one mapping should be provided for required report content (subpart citation) versus the CEDRI template elements (i.e., spreadsheet cell).
- It is unclear that the CEDRI system templates will comport with subpart requirements. It has been typical in such systems that data not required by individual subparts is requested, and CEDRI apparently will reject reports that do not include this extra information. This concern is exemplified in this proposal, which requires report certifications even where it is not required by a part 60 subpart. Similarly, the CEDRI system requires facility information that may or may not be required by the individual subparts. EPA must not cause facility non-compliances by refusing to accept reports because they do not contain data that is not authorized by regulation and the associated PRA authorization.
- Similarly, it is unlikely that the CEDRI templates will always include all required information or compliance options. Resource limits will make it difficult to include all potential report elements and compliance options in the templates. Yet, CEDRI may not allow facilities to submit reports if all required data elements are not completed in the template.
- Also, the proposed reporting language assumes that the CEDRI template for a particular subpart will include fields for all continuous monitoring and excess emission possibilities. If EPA expects to have multiple templates for different compliance options or to not include all potential compliance options in a subpart's template, the proposed regulatory language should be revised to only require CEDRI reporting for the information that is included in the template.

EPA only has to look at the well-documented issues associated with other electronic data systems to anticipate the massive problems this proposal will generate. It is noteworthy that even after many years the ERT system still cannot be used for all types of performance tests. Feedback from other electronic reporting efforts (like DMR's and greenhouse gas reporting) indicate a beta testing step can identify and resolve many issues prior to initial implementation,

thereby reducing the likelihood of non-compliance due to system inadequacies. Similarly, as was found to be highly successful in implementing the greenhouse gas reporting rule, a "sandbox" provision can greatly lessen implementation problems and reduce system-induced non-compliance.

A sandbox is a standalone version of an application not connected to the master database. You can log into the sandbox and try your inputs, make changes to your input system, identify missing data elements in the template, etc. without harming the "real" database. Once there is a complete template and you have a workable input system, you then log on to the real application and enter your data. This would be a good way to test the XML templates and for facilities to test their input systems. A "sandbox" test differs from a "beta test" in that it's available in parallel to the actual application and would not, as beta testing does, only test a preliminary version of a template. This is important, since there are so many potential report variations in part 60 reports, that even a beta test will not test all possible variants.

API therefore, strongly recommends provision of a sandbox and beta testing of all CEDRI templates for the rules covered by this proposal and for all future changes and additions. API members would volunteer to participate in such an effort for the rules that impact our industry.

Because of the complexity of transitioning to this system, API also recommends that, at least for subparts where there are expected to be a great many submitters or where reports are particularly complex, EPA provide training classes and/or webinars on the use of the system prior to implementing each template.

XVI. EPA Must Remove Computer Jargon from the Regulatory Language and Make the Final Regulatory Language Flexible Enough So As Not to Require Amendments as Computer Technology Changes.

Use of computer jargon should be avoided, particularly in regulatory language, to make these systems less off-putting to users and to allow for future changes in computer systems without having to amend the regulations. Unless one is a computer specialist, it is very difficult to follow the proposed requirements or the instructions. For instance, the boilerplate rule language proposed for incorporation into most part 60 subparts in this proposal talks about an "electronic file format consistent with the extensible markup language (XML) schema." Incorporating such computer jargon into regulatory language just adds confusion, since most readers have no idea what it means, and imbedding it in a regulation will require all of those paragraphs which use that language to be amended as computers evolve. This phrase appears 71 times in the proposed rule amendments, which clearly would require a significant and slow rulemaking to revise when the XML computer language is supplanted in the future. API supports providing for electronic uploads of required information, rather than allowing only

manual entry, but believes the specifics of that alternative should not be included in the regulatory language. API strongly encourages EPA to remove computer jargon, particularly jargon specific to a particular computer system or language, from the regulatory text when it is finalized and to clearly explain it when it is used in the rule preamble, the CEDRI and ERT web pages and in the system guidance documents. Rather, we recommend that the regulatory language indicate that electronic uploads of required data are allowed using the methodologies specified in the CEDRI and ERT manuals.

XVII. EPA Must Provide Backup Options to Prevent Non-compliances Due to CEDRI Operability Issues

The proposal makes no allowance for the realities of computer systems, computer system complexities, computer system capacity, or computer system vulnerability. This rulemaking must provide for an alternative reporting option for cases where a facility is unable to submit electronically despite a good faith attempt to do so. Specifically, submission of written reports or non-CEDRI electronic reports should be allowed if 1) the CEDRI system is unavailable for more than 4 hours in the three days prior to the submission deadline, 2) if CEDRI will not accept a report in the three days before the submission deadline, or 3) if Preparers or Certifiers cannot be registered within the week before the deadline due to system problems. Alternately, facilities should be given an additional three days after CEDRI becomes available after an outage to submit the report electronically if they prefer that to submitting a written report. Because CEDRI reporting is required for compliance, the Agency has a responsibility to provide a readily usable backup system or to only provide CEDRI as an alternative to written reporting.

Anticipated CEDRI computer issues include:

- CEDRI is unavailable due to technical problems, holiday or maintenance outages, hacking, etc., including transmission facility outages and power outages in the area of the facility. Even a short website or Internet outage can be a problem.
- CEDRI is unavailable (including unreasonably slow responses) because it cannot handle the number of reports being submitted. Typically, reports are filed near the deadline since reporting deadlines are generally just adequate to gather, tabulate, and check the required data. Additionally, many part 60 rules have the same reporting deadlines. Thus, there will be multiple, simultaneous submissions that could slow, delay or overwhelm the CDX system. This has been observed in the past. Similarly, Preparer and Certifier registrations will tend to occur around the submission deadlines, and that portion of the system could be slow or overwhelmed.

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- CEDRI is unavailable because of changes in EPA's systems. It is common to find EPA web pages have been moved, renamed, or removed.
- CEDRI reporting options differ from regulatory requirements (too much, too little, different format, doesn't account for a compliance option, etc.) and the CEDRI error checking prevents the submission. This could be due to template development errors, a deliberate decision not to include a little used compliance option in the template, or subpart or general provisions amendments. We discuss the update issues further below.
- CEDRI locks key personnel (i.e., Preparer, Certifier) out of CEDRI (this has happened).

The CEDRI error checking system has been known to improperly prevent report submission. To prevent non-compliances, the error checking system should be revised to provide warnings but not prevent uploads. If leaving an answer blank is appropriate, the system should allow this. If entering text in a box expecting a number is appropriate, the system should allow this. To this end, API also recommends EPA include general comment fields throughout the CEDRI templates that can be used to report required information that doesn't have a specific field or to include explanatory information.

XVIII. EPA Must Address Future Subpart Revisions.

Whenever a part 60 subpart or the part 60 General Provisions are revised, reporting requirements typically change and existing CEDRI templates may no longer provide for a compliant report. In such cases, some data elements may no longer be required and new ones may need to be added. This rulemaking must deal with that situation, since the criterion in the proposal is whether there is a CEDRI template not whether there is a valid template. While a supplemental written report might be used for providing new information, that is inefficient and does not deal with template data that is no longer required. Therefore, API recommends that EPA provide that, upon revision of a part 60 subpart that impacts reporting requirements, written reporting be allowed until the applicable CEDRI template is revised and noticed in the Federal Register.

XIX. CEDRI Must Be Capable of Handling the Many Special Report Situations Prevalent in the Real World or a Written or PDF-upload Alternative Be Provided.

Reports could be refused by CEDRI because the reporting format does not allow reporting in all of the combinations/permutations possibly required. For instance, CEDRI might reject a report when a particular periodic report must include an unusual explanation, such as for a process or monitor outage or out-of-control period, or when a performance test uses a method not supported by the ERT. A simple way to ensure these situations can be handled is to allow a

written submission or the upload of a scanned PDF if the required report contains required data elements that CEDRI cannot accept.

Similarly, CEDRI must be able to accommodate reports that differ from the standard format for any of the following reasons, among others.

- A single periodic report provides information covering multiple subparts. For instance, it is common to file a single report covering part 63 and part 60 requirements for a particular set of emission points. Such reports will typically include more data elements than the part 60 subpart requires. Similarly, it is common to file a joint part 60 and Title V report. It is also very common to use one report for several part 60 subparts (For instance, a single report covering part 60 subpart K, Ka and Kb tanks.)
- A report that contains additional information that has been required by the appropriate permitting authority or through a Consent Decree.
- A report containing different information because of an approved alternative monitoring plan or alternative emission limitation or that used a draft or generally allowed modification to a performance test method.
- A report containing different information due to an alternative site-specific monitoring plan as specified or allowed by a particular subpart. For instance, site-specific fuel monitoring plans are allowed by several subparts, including part 60 subpart GG.

XX. CEDRI Needs to Accommodate Efficient Data Entry.

EPA should make efforts to minimize dual reporting, both in CEDRI between different part 60 standards (e.g.: subparts J and Ja) and between CEDRI and written reports (e.g.: subpart J and part 63 subpart UUU, Title V reports, and NSR CD reports). These efficiencies are in place today in many places, and it appears the current CEDRI approach will eliminate the efficiencies of combining reports. The extensive additional burdens associated with this change are not justified or even identified in the proposal or the PRA analysis.

It is also common for considerable information in a part 60 periodic report to be unchanged from report to report. Thus, API requests that CEDRI provide the option to copy data from the previous report rather than having to manually re-enter the data. For example, submitters should not have to manually retype the make, model, and serial number for each CEMS every 6 months.

EPA should also develop templates that recognize that industry may be using one CEMS to comply with multiple rules (e.g.: H₂S CEMS on the fuel gas drum to comply with part 60 subpart J for some heaters and part 60 subpart Ja for others) and set up a feature so the same CEMS data need not be entered twice.

Many refiners are subject to consent decrees that require submission of data that overlaps or includes data required by part 60 subparts. API recommends that EPA specify that data submitted through CEDRI need only be referenced in consent decree reports and does not have to be duplicated.

In some cases, periodic reports may be required to contain significant quantities of data. CEDRI should provide for an efficient way to enter such large blocks of data. A reasonable work around is an allowance to upload PDF files with supplemental data.

Since, as discussed throughout these comments, multiple reports will be required where one has sufficed in the past, there will be a vast expansion in the number of required certifications and the burdens associated with such certifications. To that end, API recommends that EPA develop a system for a combined certification, such that one certification entry can be used for all of the electronic entries associated with a periodic report submission.

XXI. CEDRI Must Provide for Report Updating and Correction

Occasionally reports must be updated or corrected. It is unclear in the proposal how such revisions are accommodated in the CEDRI and ERT systems. API requests EPA clarify this point in the final rule and, if such capability is not currently present, that it be added.

XXII. No Benefits Should Be Claimed for CEDRI Reporting Since Those Burden Reductions Were Already Claimed and There is Little Likelihood that CEDRI Reports will Replace a Significant Volume of Written Reports in the Foreseeable Future.

EPA estimates that CEDRI and ERT reporting will replace approximately 43% of reports to States in about 3 years (See Table 4 of the preamble and the associated discussion), based on an Environmental Council of the States (ECOS) survey that asked states if they intended on integrating EPA's e-Reporting program through the CEDRI into state and local agency programs. API believes it will take much longer than that, probably as long as a decade, for CEDRI and ERT to be able to handle the myriad report variants and data element variants associated with the current part 60 rules completely and to accommodate rule revisions that will occur as reporting moves to the CEDRI platform. Nor, in most cases, does this proposal even envision requiring all periodic report information required by a particular subpart to be submitted electronically. So,

even if a State accepts the EPA electronic information, a written or PDF report would still be required to be sent to both the State and EPA in most cases in order to provide the information not included in CEDRI. For instance, for the large number of subparts that require fugitive emission monitoring, only the small portion of the periodic report associated with excess emissions or continuous monitoring must be submitted electronically. Another example is the proposed requirement (via the amendment of §60.107(c)) to submit subpart J periodic reports electronically. In this case, one report content requirement (§60.107(c)(4)(vi)) is excluded from electronic reporting and thus both electronic and written reports will always be required to both EPA and to the State. Thus, even if 43% of States actually begin using CEDRI information for some reports by year three, it will be for a very small percentage of part 60 reports, since complete and fully functional templates must be developed for each subpart and each report type. Even the ERT system which has now been in place and under development for some time, still cannot handle all EPA Methods, and, thus, many performance test reports must still be reported by other means or only be partially reported using the ERT.

API believes it will take significantly longer than three years for States to rely on CEDRI and ERT in place of their own reporting systems to any measurable extent. In fact, many States already have electronic reporting systems of their own in place and are highly unlikely to abandon those in favor of CEDRI.

Furthermore, in 1999, EPA finalized amendments¹⁰ to the part 60 and 61 General Provisions (specifically §§60.7(a), 60.19(b), 61.04(b)) to allow electronic recordkeeping and reporting (along with other changes) and, in that proposal,¹¹ (which they reaffirmed in the final rule preamble) EPA claimed 780,000 hours of burden reduction for reducing report frequency and allowing electronic reporting and recordkeeping.

Thus, API believes that all of the burdens associated with reporting through CEDRI are additional to current burdens and that there will be no savings starting in year 3 as EPA claims. In fact, burdens will increase due to the use of CEDRI, as discussed elsewhere in these comments.

XXIII. The Burdens Associated with Requiring The Use of a Specialized Electronic System Should be Reflected in the Cost and Burden Analyses.

In addition to not recognizing the costs and burdens associated with losing the current efficiencies of combined compliance reporting, this proposal does not account for the burdens associated with users maintaining computer expertise and knowledge of the CEDRI and ERT systems as they change. It is notable that even the relatively mature and limited ERT system

¹⁰ See Ibid.

¹¹ See 61 Fed. Reg. 47840 (September 11, 1996)

underwent six revisions in the last year¹². Sources and testing companies will have to put in place specialized resources to follow such program revisions and modify their data entry to accommodate the changes. Furthermore, one needs only to read this notice and the ERT webpage to understand that computer expertise is required to even understand the system instructions. While that burden may have been manageable for the relatively few subparts and reports where the ERT is currently required (i.e., performance test reports) and for larger testing contractors, with in-house computer expertise, it is unclear that it will be manageable for the multitude of small testing companies to which this requirement is applied by this proposal (see Comment XIV.)

Similarly, EPA has posted¹³ an 80 page manual to explain how to access and use the CEDRI system. The details explained in that manual demonstrate the inflexibility of the system, the massive amount of effort that will be required to register and maintain facility and user information, and the inefficiencies associated with having to enter information on forms and through pulldown and other types of menus.

XXIV. Comments on Delegated Reports.

Under this proposal, EPA rescinds any current approval under part 60 for reporting only to the delegated authority once a report can be filed through CEDRI or ERT. While we do not have an estimate of how common such delegation is, removing it increases burdens, since two reports will now be required where one suffices today. It is our experience with the ERT system, where electronic reporting has been required for several years under some regulations, that the electronic report is generated from the written report, and we expect the same to be true for CEDRI reports, thus there is no reporting efficiency. Sites have developed sophisticated systems for gathering data for reporting, and CEDRI data entry will be an add-on to those systems and not be a replacement.

XXV. Comments on Use of ERT for Reporting Performance Tests

1. The preamble claim that this proposal will reduce performance test recordkeeping and reporting burdens is false since 1) the ERT system cannot handle all potentially required test methods and is unlikely to ever do so as test methods are added and modified, thus requiring both electronic and written reporting in most cases, 2) many test methods are modified by individual part 60 subparts and it is unclear the ERT will ever be able to handle those modifications, 3) States and Title V still require written or PDF records and reports, 4) formal reports (paper or PDF) are needed as a deliverable to demonstrate the testing contract has

¹² See the ERT update history available through <http://www.epa.gov/ttn/chief/ert/index.html#template>.

¹³ See <http://www.epa.gov/ttn/chief/ert/cedriguide.pdf>

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been completed, and 5) because experience demonstrates that such data entry cannot be done without first generating a full performance test report.

2. Under this proposal, electronic reporting will be required if a test method is supported by the ERT. However, most performance tests involve the use of several EPA test methods (e.g., one for stack flow, one for stack moisture, one for stack oxygen, and one for each pollutant of interest). However, under the proposal language electronic submission would be required for any performance test where any one of the methods used is supported by the ERT (e.g., if stack flow is determined by one of the Method 2 alternatives), even if the pollutant concentration methodology is not supported by the ERT. There does not seem to be any justification for requiring electronic submission and the associated additional burdens, unless all of the methods used to determine a pollutant's emissions are determined using ERT-supported methods. There is no value, for instance, in submitting a stack flow electronically and the pollutant concentration and mass flow calculation by written or PDF means, since the electronic information cannot be used on its own. Thus, API recommends that the proposal language be revised to only require electronic submission where pollutant emissions were determined using only ERT-supported method.

3. Additionally, EPA has not developed or articulated a reasonable approach to using information that is uploaded through the ERT. The claimed benefits in Section III of the preamble are improved emission factor development and better information for rulemaking. However, no system has been identified or put in place to provide any quality control on ERT performance test submissions. Nor is there any system for relating reported performance test emissions with operating information, design information, control systems, etc. Nor is there a system identified for integrating electronic and non-electronic information as discussed in the previous sub-item. Thus, there are few situations where ERT submissions can be used for developing high quality or useful emission factors. Relative to using this information for rulemaking, the same factors prevent using raw results. For rulemaking, the available emission data has to be categorized against operating, design and control information. Furthermore, performance test data only represents operation at maximum conditions (as required by regulation) and, thus, does not provide information on other operating points or variability. As a result, performance test data is not often used for rulemaking. It is sometimes used to identify pollutants of concern, but that information generally requires use of specialized test methods that are not used in the normal performance tests covered by the ERT. Thus, the information gathered through the ERT is unlikely to be adequate for sound rulemaking and information collection efforts for rulemaking will likely continue unabated with no overall reductions in time or effort required.

XXVI. Applicability Dates Must Be Included in the Proposed New Language.

Since some CEDRI and ERT capabilities currently exist, the proposed requirements to use these tools would appear to be applicable retroactively for most subparts. Part 60 requirements may only be made applicable from the date of their proposal. Thus, in every instance (including in subpart A) where a part 60 subpart does not already contain either or both of these requirements, a phrase must be added to clarify that the electronic submission requirement does not apply to reports covering time periods prior to the date when the electronic reporting requirements are finalized.

XXVII. The Applicability of the Revisions Must be Clarified in the Final Amendments.

Table 1 of the proposal preamble lists part 60 subparts to which this proposal does not apply. However, nothing in the proposed regulatory language excludes those subparts, particularly the proposed amendments to subpart A, which are generally applicable to all part 60 subparts, including those listed in Table 1. For instance, proposed §60.7 requires all part 60 excess emission reports to be submitted via the CEDRI system and proposed §60.8 requires all part 60 performance test reports be submitted using the ERT. Similarly, electronic reporting requirements are made applicable to all part 60 subparts by the proposed amendments to §§60.13, and 60.19. Thus, it seems, without modification, the proposed language will make electronic reporting a requirement for the subparts in Table 1 that EPA states in the preamble will not be subject.

API requests that EPA exclude the part 60 subparts listed in Table 1 of the proposal preamble from the CEDRI and ERT requirements by revising the proposed regulatory language in Subpart A, when these amendments are finalized.

XXVIII. EPA Should Focus on Making the ERT and CEDRI Systems Effective and Useful and Not Waste Resources Trying to Collect Emission Inventory Information, Which is the Responsibility of the States.

On page 15109 of the proposal preamble, EPA states "In lieu of activity data, collecting long-term emissions data would also provide useful data for inventory and rule development purposes. We are specifically requesting comment on whether and how long term activity or emissions data should be submitted electronically."

Collecting emission inventory data is a State responsibility. API, therefore, recommends EPA work with States to secure emission inventory data and to improve emission inventory systems, where needed. EPA's limited resources need to focus their efforts on making the ERT and CEDRI, current and complete, user friendly, and reliable. As discussed above, this effort is likely to take many years and EPA should not divert resources for information collection that is the responsibility of others and not required by law.

XXIX. Compliance Dates for CEDRI Reporting Are Missing From Two of the Proposed Amendments and Need to Be Added.

Proposed §§60.334(j)(5) and 60.4395 require that all continuous monitoring and excess emission reports required by their subparts (GG and KKKK, respectively) be submitted electronically whether or not a CEDRI template has been made available and the compliance time provided in other places (e.g., 90 days from availability of the template) is absent for these subparts. This should be changed to the standard language used throughout this proposal that only imposes electronic reporting requirements 90 days after an applicable template is available and the other changes we recommend in general are incorporated.

XXX. Other Comments.

1. Proposed §60.4(b) states "Information submitted in paper format must be postmarked no later than the date that the report is required to be submitted to the EPA's CDX electronically." Since the reporting due dates are set in the regulation, not in the CDX system as this sentence seems to suggest, this sentence is unnecessary and confusing and should not be finalized. Instead, we recommend the submittal sentence further in §60.4(b) be modified to clarify how written reports are handled, as follows: "All reports must be submitted **or postmarked, as applicable,** by the deadline specified in the subpart of interest, regardless of the method by which the report is submitted."

2. Proposed §§60.8 and 60.13 include language dealing with reports that might contain Confidential Business information (CBI). They call for submitting the non-CBI information to the CEDRI system. However, it is unclear the CEDRI system will accept such partial reports. CEDRI must either accept reports containing partial information or have a way for submitters to indicate CBI information is being withheld and that the partial submission is acceptable.

Attachment C

Technical Review of Western Climate Initiative Proposals to
Meter Fuel and Control Gas

**Technical Review of Western Climate Initiative Proposals to
Meter Fuel and Control Gas**

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MuleShoe Engineering**

Prepared: February 16, 2010

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Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the “most accurate” volumes if the gas was metered as a “fuel” stream and a “control” stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to “provide the rigor required for either cap-and-trade or offset programs”. The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer’s numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The “Per Company” column below assumes 2,000 wells per company, “Total WCI” column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under “Cost of Implementation” below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well (\$k)	Per Company (\$million)	Total WCI (\$million)
RTU Replacement	\$3.5	\$7	\$350
Host/Database		\$15	\$750
Site Modifications	\$30.0	\$60	\$3,000
Total Capital	\$33.5	\$82	\$4,100
Annual Operating Costs	\$1.5	\$3	\$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate “accuracy” in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different “emissions factor” on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as “on demand” in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators

take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 “turndown ratio”. Turndown ratio is a measure of ability of a measurement device to provide similar “accuracy” over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from “off “ to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer’s estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since “rich” liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

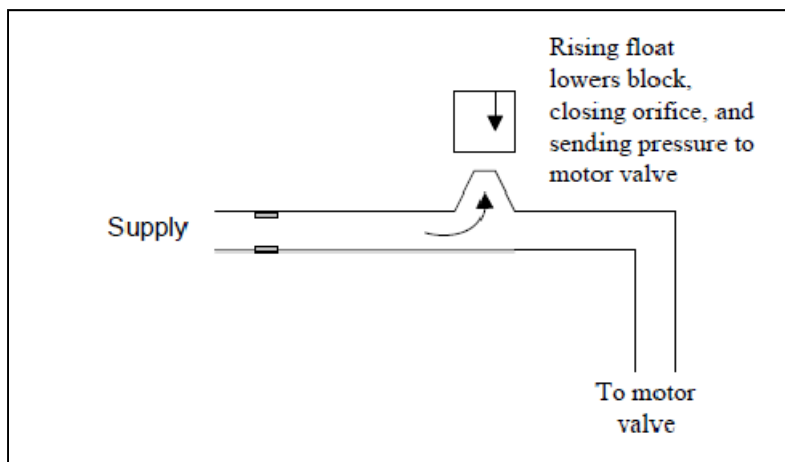
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

4. *Pneumatic devices*

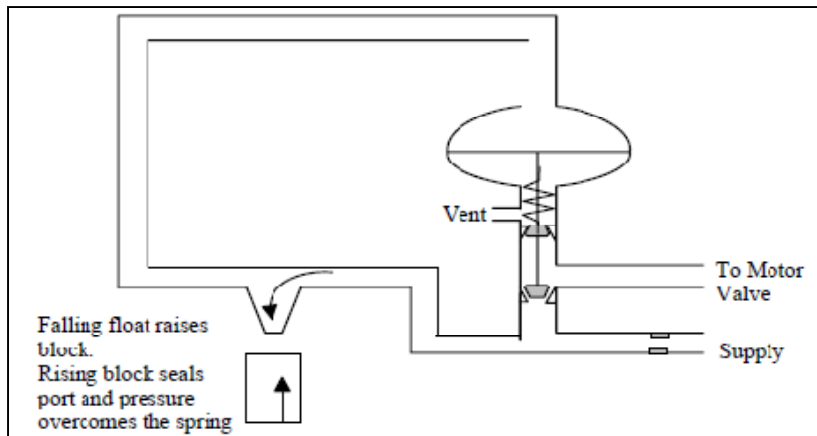
I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either “Throttling” or “Snap Acting”. Bleed characteristic is either “continuous bleed” or “no bleed”. An example of a Continuous Bleed, Throttling controller is shown below



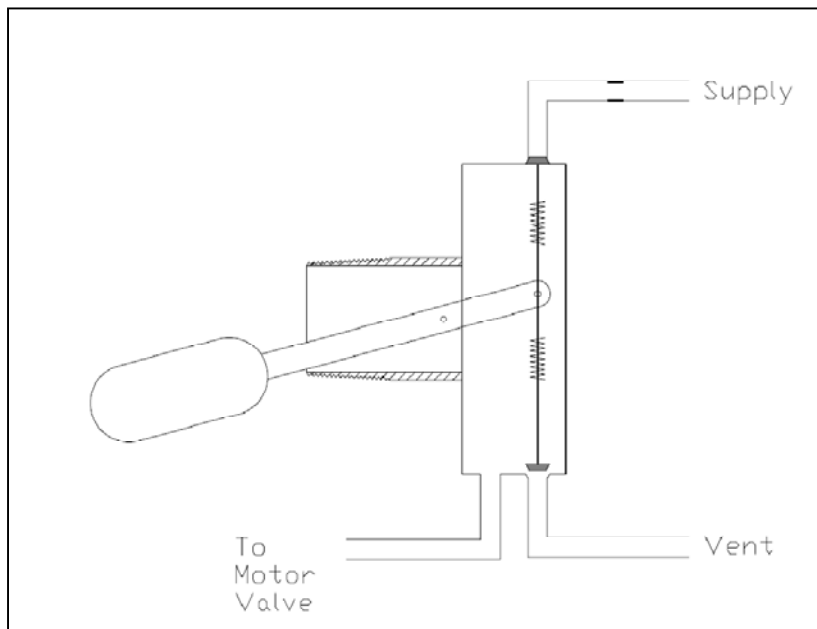
In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled

devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A “No Bleed” controller would look something like:



This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the

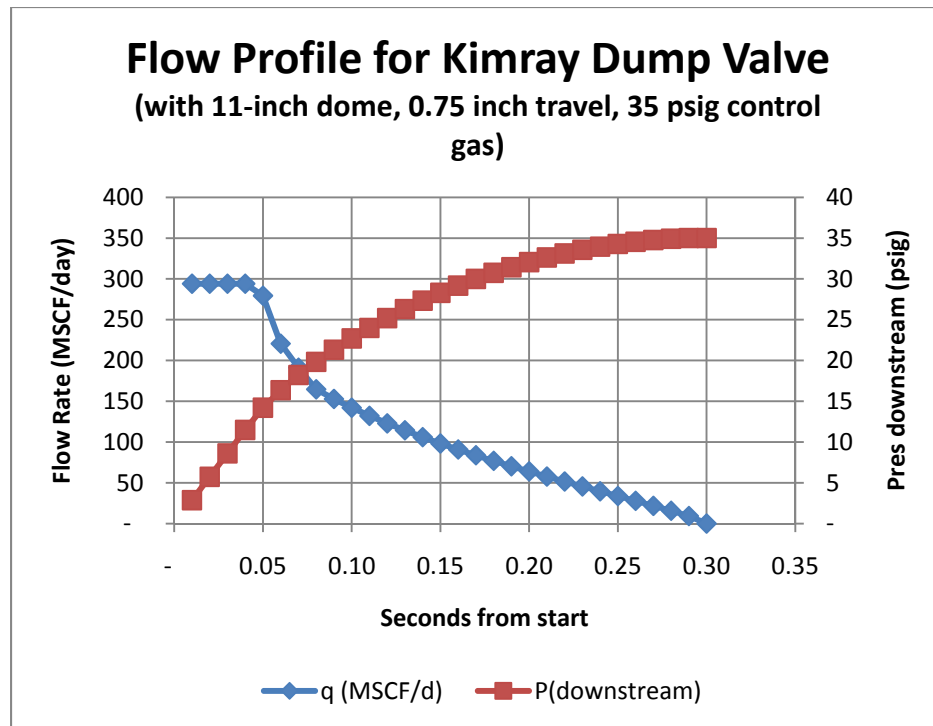
vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it “snaps” open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas is used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing “bleeding” of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can’t be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a “jerky” action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft^3) and the diaphragm dome is 0.04 ft^3 (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft^3 . At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about “meter accuracy” above I always said “accuracy”. “Accuracy” is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of “accuracy” is encompassed in the terms “repeatability” and “uncertainty” which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

“Repeatability” is a measure of a device’s ability to report the same output for a given set of inputs. Many things can impact a device’s repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable

repeatability occurs when the standard deviation of the sample data is within $\pm 0.05\%$ of the mean value.

“Uncertainty” is the “dead band” of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device’s calibrated span. For example, a digital pressure transducer may have a stated uncertainty of $\pm 0.5\%$ which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices’ uncertainty is less than $\pm 2.0\%$ (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is “latency”. Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are “inferential” technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli’s development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. *Gas Analysis*

Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed $\pm 25\%$.

These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

This device has potential, but the smallest meter (1/2" ID) would register zero during pilot flow and would have a dP less than 7 inH₂O (0.25 psi)

while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

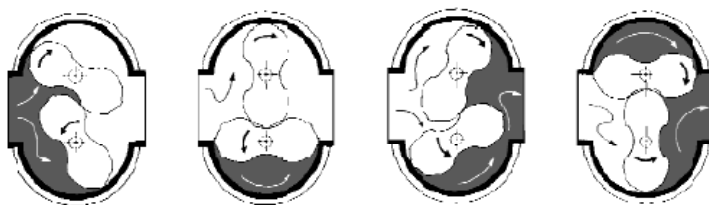
The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to “measuring” gas volumes instead of “inferring” a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. *Diaphragm Meters*

The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. “Household quality” meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H₂S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). “Industrial quality” meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or “yellow metal” is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

The volume of gas discussed in this application kept leading me to devices like “Thermal Dispersion Meters” (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

- a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.
- b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a “valve open” clock on the supply line, which (in conjunction with manufacturer’s data and Engineering analysis) would result in a better volume than attempting to meter the gas.

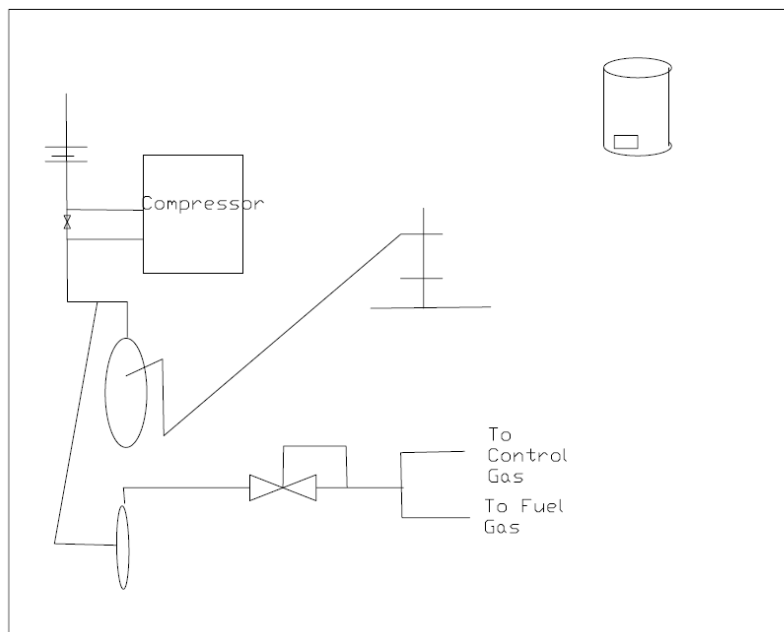
- c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Coriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.
- d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can’t be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

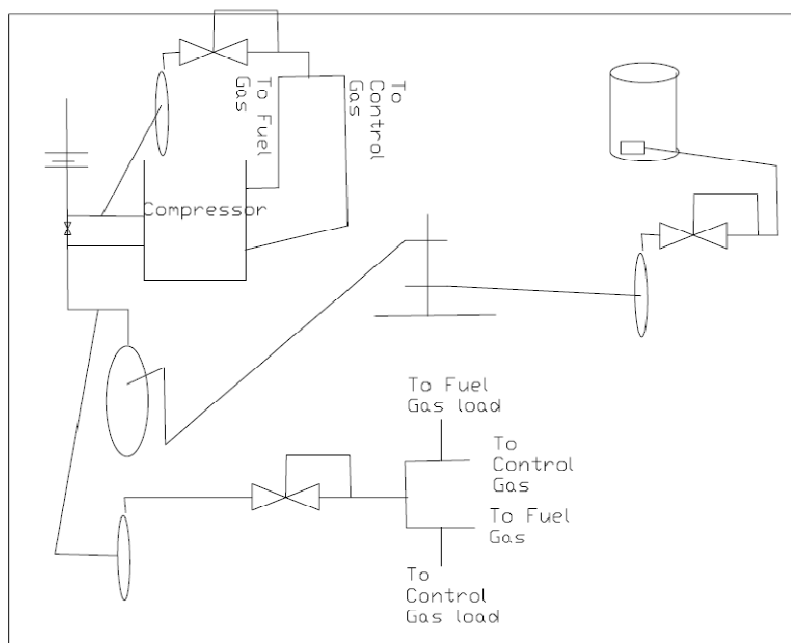
On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a “standard” wellsite where fuel-gas measurement equipment can be “relatively easily” installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since

compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a “typical” wellsite, “typical” automation system, or “typical” host/database modification because there is no such thing. There are companies within the WCI area of operation that don’t have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I’ve worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at

http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at <http://www.capp.ca/GetDoc.aspx?DocID=146286> for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I’ll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of \$4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately \$3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data poling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost \$15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend \$750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At \$1,200/day that is \$12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be \$30,000/well—100,000 wells would cost \$3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a \$5/MMBTU sales price the cost of this lost production is \$600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is \$150,000/year which works out to about \$750/meter/year or \$1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.

Attachment D

API Comments on EPA's White Paper on Liquids Unloading



June 13, 2014

Mr. Chris Frantz
US EPA
109 T.W. Alexander Drive
Mail Code: #143-05
Research Triangle Park, NC 27709

Re: EPA VOC/Methane White Paper on Oil and Natural Gas Sector Liquids Unloading Processes

Dear Mr. Frantz:

The American Petroleum Institute (API) appreciates the opportunity to provide feedback on EPA's White Papers on Methane and Volatile Organic Compound (VOC) Emissions in the Oil and Natural Gas Sector. On April 15, 2014, EPA released, for external peer review, white papers that focus on technical issues covering emissions and mitigation techniques targeting methane and VOCs from five separate emission sources. As noted in the Obama Administration's Strategy to Reduce Methane Emissions, EPA will use the papers, along with the input from the peer reviewers and the public, to determine how to best pursue additional reductions from these sources. As described below, API does not believe additional methane controls should be required at this time.

API represents over 590 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly \$2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Many of our members will be directly impacted by any policy decisions that may arise from this effort regardless of whether it informs either regulatory action by the federal government or states.

API provided technical feedback and expertise throughout the development of the New Source Performance Standard (NSPS) Subpart OOOO rule. Each source addressed by the white papers was considered for regulation during the development of the NSPS and EPA, ultimately, chose not to regulate them. While our understanding of emissions from oil and gas production continues to evolve, the fundamental merits of requiring additional regulatory control of these sources is unchanged. As such, API continues to believe that no additional regulation of oil and gas production sources is necessary prior to the full implementation of the NSPS OOOO rule and a subsequent evaluation of emissions.

Considering the potential for significant impact on our members that may arise from any policy decision stemming from the white papers, API has developed significant technical comments (see attached) to address a number of technical inaccuracies about the sources and the conclusions that have been drawn. Barring significant revision, API believes that the current white papers are simply insufficient to inform sound policy decisions and that simply posting comments on the current version will not result in an informed process. As such, API recommends the EPA take the following steps:

- Revise the white papers to correct any fundamental flaws or inaccuracies that were identified in response to peer review and stakeholder comment (e.g., improved source descriptions, improved understanding of emission quantification, misconceptions about emission mitigation options)
- Develop a response to comments document that clearly identify the changes the EPA makes to the revised white papers and explains the Agency's rationale for those changes
- Identify emission studies in progress that will better inform EPA's understanding of these source emissions and await the pending study reports

In recent years, there have been significant swings in the national emission estimates from oil and gas production sources, including those covered by the white papers, which indicate a necessity to continue collecting data to improve our understanding. Much of this learning will come from improved reporting under Subpart W of EPA's Greenhouse Gas Reporting Program as well as current studies and others planned in the coming years, which involve taking direct measurements of the sources. EPA and industry would both be well served by allowing these studies to inform policy.

Again, we appreciate the work by EPA to initiate these white papers and the opportunity to provide feedback on this effort. API and its members are dedicated to working with EPA to improve our collective understanding of these emissions and providing the technical operator experience that's needed to do so. Recognizing the potential for these white papers to inform not only EPA but other government agency policy decisions, we request the opportunity to provide additional feedback to the Agency in response to any of our comments in advance. Furthermore, we again offer our experience and expertise as EPA moves into the policy evaluation phase of this effort.

Sincerely,

/s/

Matthew Todd

Cc: Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

Comments on

**Oil & Natural Gas Sector
Liquids Unloading Processes**

by EPA Office of Air Quality Planning and Standards

June, 2014

**Prepared by
The American Petroleum Institute (API)**

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Executive Summary

The U.S. Environmental Protection Agency (EPA) has developed a draft document titled *Oil and Natural Gas Sector Liquids Unloading Processes* (referred to as “the White Paper”) to, as stated in the Preface, seek input and solidify its understanding of the methane and volatile organic compounds (VOCs) emissions from leaks in this industry sector. The American Petroleum Institute (API) hereby submits its input and comments in this document.

The White Paper does not meet the goal of being a high quality technical document intended as a resource to inform EPA’s deliberations regarding emissions due to venting of wells to assist liquids unloading. Rather than a robust compilation and analysis of available information regarding venting of wells to assist liquid unloading, the White Paper appears to be a summary of the information sources referenced. In some instances, the summaries of the underlying sources are incomplete and information is incorrectly mischaracterized. There are misunderstandings and incorrect/inaccurate statements scattered throughout the White Paper and additional information sources, such as the vast amount of industry technical literature regarding management of well bore liquids, are not included in the scope of the White Paper sources. No discussion regarding the limitations of the underlying sources is presented in the White Paper and there is no critical analysis of the accuracy or validity of the underlying sources or the information summarized from them in the White Paper. The logic and underpinning evidence leading to the conclusions and assertions made in the White Paper is not clearly presented.

More clarity of focus on venting of wells to aid liquid unloading, which is the source of emissions, rather than wellbore liquid loading in general would improve the White Paper. Understanding the reasons and causes for using well venting to aid in liquid unloading is the key to understanding and evaluating potential approaches to reduce well venting and emissions. Managing the use of venting to affect liquids unloading should be the predominant focus of the white paper. To adequately evaluate options to reduce venting of wells and the emissions that result, it is necessary to understand the reasons that wells are vented, alternatives to venting that will still provide for well-bore liquid loading management, and the envelope of conditions where these alternatives are feasible. This does not appear to be the focus of the White Paper and adequate information is not provided.

Well-bore fluid dynamics and the portfolio of techniques, practices, and technologies that the industry uses to manage well-bore liquids are complex. Notwithstanding this complexity, the White Paper needs significant improvement in content, organization, and data sources to be useful if it is intended to inform EPA’s understanding and evaluation of potential options to reduce emissions from venting of wells for liquids unloading.

Following the public announcement that a white paper was being drafted on emissions associated with liquids unloading, API submitted early feedback (March 2014) to EPA and those comments are attached for further consideration.

Highlights of key review comments discussed in more detail later in this document follow:

- Based on deeper analysis of the GHGRP data, emissions from venting for liquid unloading are mostly driven by a relatively small number of operators and a relatively small subset of wells with less than 0.5% (10 of 1991) of the datasets at the “subbasin” level accounting for more than 50% of the

emissions. This skewed distribution is consistent with the API/ANGA Survey Report data. This strongly suggests that a targeted type intervention is more appropriate than a broadly applicable regulatory approach.

- Further illustrating the niche issue of venting for liquid unloading, the GHGRP data shows only about 13.5% of U.S. gas wells vented for liquids unloading in 2012. Given the fact that most U.S. gas wells are low producers and likely subject to liquids loading this indicates that managing well-bore liquids without venting is significantly more common than venting.
- The White Paper's assertion that plunger lift systems are an effective emission control technology is not supported by the data that shows wells with plunger lifts have a higher frequency of engaging in venting, a higher number of vents/venting-well/year, and account for a disproportionate percentage of well venting emissions. Despite plunger equipped wells being less than 40% of the wells in the API/ANGA survey they account for about 70% of the emissions.
- The use of advanced formation energy management (smart automation) to aid liquid unloading while minimizing venting, for wells with plunger lift and wells without, is not adequately described.
- The control technology discussions and costs in the White Paper appear to be solely based on lessons learned documents from the Natural Gas Star Program. These lessons learned documents were developed to foster technology transfer, which they are adequate to do, but have never been subjected to the level of critical expert review necessary if they are to be used as foundational technical information sources.

A. Introduction

The description of liquids loading of well-bores is incorrect which indicates a fundamental misunderstanding of well-bore liquid-loading, the techniques and tools that are used to manage liquids loading, and the role that venting has in liquid unloading. Additionally, there are several misunderstandings, incorrect/erroneous statements and use of terms that do not have any meaning in the context of liquid loading of well-bores.

Liquid loading of well-bores occurs when the gas velocity up the well-bore is not sufficient for the gas to transport liquids up the well-bore. When a vertical liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and can reduce production rate to the point where the well can quit flowing. The volume of flow up a well-bore is a function of the formation deliverability (inflow rate), the **flowing** formation pressure near the well-bore, and the cumulative resistance to flow expressed as pressure drop. The cumulative resistance to flow is the sum of the fluid column in the well-bore's hydrostatic pressure, the flowing friction up the production tubing/casing, surface equipment pressure-loss/back-pressure, and the pressure of the collection line that a well is flowing into. As the cumulative resistance to flow approaches the flowing formation pressure the rate of production will decrease and, if the cumulative resistance equals or exceeds the formation pressure, the formation will cease flowing reservoir fluids into the well-bore. As wells deplete, the formation pressure near the well-bore and the inflow-rate decreases which decreases the volume flow rate of reservoir fluids and consequently the velocity of flow up the well-bore. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes,

production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore.

The statement that:

“the accumulation of liquids in the well can occur when the bottom well pressure approaches reservoir shut-in pressure”

is not correct and is rendered somewhat meaningless by the use of the term “*reservoir shut-in pressure*” which does not have a meaning in this context. “*Reservoir shut-in pressure*” is more appropriately referred to as “average reservoir pressure” which is defined as the volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries. It is misleading to call the build-up pressure at a well during a shut-in “reservoir pressure”.

Techniques and tools that operators use to manage liquid loading **that rely on formation energy** focus on reducing resistance to flow or by raising the pressure in the near-wellbore. Lowering surface pressure with compression, wellsite debottlenecking, or lowering gathering system pressure reduces surface resistance to flow. Reducing flowing fluid friction through materials choices can assist in reducing flowing friction resistance to flow. Hydrostatic resistance is affected by surfactant/soap injection or running plungers to try to reduce the work that is done by the gas in lifting liquids (surfactant/soap) or make it more efficient (plungers). Near-wellbore formation pressure can be impacted by stopping flow to allow reservoir fluids to resupply depleted fluids and pressure near the well bore. Flow velocity can be increased, for a given flow rate, by installation of smaller diameter “velocity” production strings in the well-bore although there is a practical limit to smaller diameters where flowing friction overcomes the effect of a smaller diameter flow path. Venting of wells to atmosphere is used to lower the resistance to flow by removing the collection system and most surface equipment backpressure. A combination of techniques may be used concurrently, such as velocity strings and surfactant/soap injection, dependent on the well and formation characteristics.

Once the formation pressure and inflow rate reaches the stage where the reservoir’s energy and flow is not sufficient to lift liquids then energy will need to be added to the well, which is commonly termed “artificial lift” but more properly termed “mechanical deliquification” of gas wells. Added-energy deliquification methods include downhole pumps (e.g., sucker-rod pumps, progressing cavity pumps, or electric submersible pumps) or gas lift which involves injection of higher pressure gas down the casing/tubing annulus and into the flow stream to increase the energy/velocity available for the gas to do work lifting the liquids. Each lift type has its specific purpose with respect to liquid rate potential, solids handling capabilities, installation/maintenance cost, reservoir drawdown potential, etc. Once a mechanical deliquification technique is installed on a well, any perceived value of venting is eliminated and venting will not occur. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology selection requires a thorough understanding of the reservoir, conditions that a reservoir is flowing into, the reservoir’s sensitivity to backpressure, the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology.

The discussion of venting (also termed “blowing down”) a well and the role of plunger lifts is partially incorrect and incomplete. The following are provided to clarify the process.

1. Venting may be either manual or automated and also relies on reservoir energy.
2. Venting may or may not be done in conjunction with shut-in periods to build reservoir energy.
3. Plunger lifts rely on the reservoir energy. Venting to reduce flow resistance and create lift is common while running plungers.
4. Plungers do improve the efficiency of a gas stream to perform liquid removal by providing a physical barrier between the formation energy and the liquid column (reducing liquid drag effects) but do not necessarily minimize or eliminate venting.
5. Minimizing venting, with or without a plunger, hinges on understanding the reservoir energy, flow resistance, and available technologies and techniques (such as shut-in periods to build near well-bore energy) to provide adequate flow rate to lift liquids without venting. Wells with plunger lifts have more variables that can be manipulated to accomplish this goal, but are not inherently able to provide smaller vented volumes.
6. Swabbing is a remedial treatment with a rig or wire-line unit that is used only when a well will not respond to other techniques to remove the liquids from the well-bore and restore flow. It is not commonly used to manage liquid loading on a frequent basis, and volumes vented during swabbing operations will generally be markedly higher than individual venting events.

B. Charge Questions

Charge Question 1

Please comment on the national estimates of methane emissions and methane emission factors for liquids unloading presented in this paper. Please comment on regional variability and the factors that influence regional differences in VOC and methane emissions from liquids unloading. What factors influence frequency and duration of liquids unloading (e.g., regional geology)?

The “Introduction” section and Section 2.0 of the white paper incorrectly represents the data sources and information summarized as “studies”. Only one of the information sources summarized, the UT Phase 1 study, is an actual emission study. The other data sources summarized (i.e., the National Inventory, the GHGRP data, the API/ANGA report, and the ICF/EDF report;) are inventory estimates and/or reports rather than basic measurement studies and should be discussed and characterized as such. These same sections also state that some information sources summarized include information regarding mitigation techniques which is not correct. What some of these information sources do include is information regarding well-bore configuration, specifically information regarding the number or percentage of wells that have plunger lift systems. As discussed later, plunger lift systems are not an emissions “mitigation technique” by any definition of the term.

Section 2.0 of the paper would benefit from inclusion of a table showing the different estimates of emissions attributed to venting of wells to aid liquids unloading at the beginning of the section.

Table 1

Well Venting for Liquid Unloading Methane Emission Estimates							
Name	Methane MT's	Total # of Venting Wells	# Venting With Plunger Lift	# Venting Without Plunger Lift	MT's per year per Venting Well	MT's per Venting Well per year with Plunger	MT's per Venting Well per year w/o Plunger
Greenhouse Gas Reporting Program - 2012	276,378	58,663	32,448	26,215	4.711	6.158	2.959
U.S. Inventory of Greenhouse Gas Sources and Sinks - 2013 (2011 Emission Year)	258,667	60,810	23,503	37,307	4.254	4.618	4.024
API/ANGA Report - 2011 data	319,664	65,669	36,806	28,863	4.868	5.207	4.584
UT/EDF Phase 1 Study	162,619			35,828	4.539	not measured	4.539
ICF/EDF Report	277,307	75,399	44,286	31,113	3.678	4.430	2.607
Note: With the exception of the UT/EDF Phase 1 Study this table is U.S. Totals Note 2: The UT/EDF Phase 1 results should be viewed with an abundance of caution. Only 9 well venting instances, all without plunger lift, were measured which is much too small of a population to extrapolate to a national or even sub-national level. Also, the supplemental information for this study indicates that venting may have been triggered on at least some of the wells measured solely to enable measurement. If this is correct, the wells were not liquid loaded, the flow volumes and dynamics would be very different from a liquid loaded well, flow would likely exceed normal production flow of the well, and flow would not be representative of an actual venting to assist unloading. Note 3: The different data sources/studies used different methane concentrations to arrive at methane emission estimates. See the individual studies for information on methane content that was used.							

a. GHGRP Data - 2012 emission year:

The GHGRP data is likely the most complete and data rich source of available information regarding the number of wells venting to aid liquids unloading, the number of plunger lift systems installed in wells, the frequency of venting, and estimated emissions. The GHGRP discussion in the white paper does not include or indicate the significant amount of information available, the granularity of information available (down to the county/formation-type combination and below), or even a cursory analysis of the emission data.

Liquid unloading is reported into the GHGRP at the sub-basin category (county & formation type) level for methods 2 and 3. For method 1, reports are made at the level of unique combinations of sub-basin category (county & formation type); pressure group (5), and tubing diameter group (3). Rather than the 251 basin level reports the white paper notes, there are

1,993 separate data sets available at the granularity described. Estimates for GHGRP reporting of emissions from venting to aid liquid unloading are based on engineering calculations (Methods 2 & 3) or representative well vent measurement and extrapolation to other venting wells in the same grouping combination (Method 1).

Data available for the 2012 emission year, for methods 2 and 3 include

- 1) Count of wells vented to the atmosphere for liquids unloading.
- 2) Count of plunger lifts.
- 3) Cumulative number of unloadings vented to the atmosphere (**Deferred in the 2012 data**).
- 4) Average internal casing diameter or tubing diameter, for all wells, where applicable.
- 5) Annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each.

Data available for method 1 includes

- 1) Count of wells vented to the atmosphere for liquids unloading.
- 2) Count of plunger lifts.
- 3) Whether the selected well in each group had a plunger lift (yes/no).
- 4) Cumulative number of vents to the atmosphere for liquids unloading.
- 5) Average flow rate of the measured well venting in cubic feet per hour.
- 6) Internal casing diameter or internal tubing diameter in inches, where applicable,
- 7) Well depth of each well, selected to represent emissions in that tubing size and pressure combination.
- 8) Casing pressure, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.
- 9) Tubing pressure, of each well selected to represent emissions in a tubing size group and pressure group combination that has a plunger lift.
- 10) Annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas.

As this illustrates, the GHGRP data includes a large amount of information that can be analyzed to help understand well venting to aid in liquids unloading.

Additional information will be available in data reported in 2015, including items shown as deferred above. However, caution needs to be taken when using this data to perform enough QA/QC to identify and exclude obviously incorrect data. For example, some data sets report emissions that are dominated by CO₂ (some 100% CO₂) which is not likely and the number of plunger lifts reported by some reporters under method 3 is extremely large which indicates these reporters did not correctly interpret the data field.

A basic analysis of the reported data indicates that

- 10 of the 1993 data sets (0.5%) reported at the granular level account for just over 50% of the CH₄ emissions reported for venting to aid in liquids unloading during 2012 with the top 72 (3.6%) accounting for just over 75%.
- At the facility (basin) & reporter level (251 non-zero data sets) the top 1 (0.4%) accounted for about 37% of the total reported emissions, the top 3 (1.2%) accounted

for over 50% of the total CH₄ reported, and the top 20 (7.9%) accounted for over 75%.

- At the parent company level (99 total), the top 2 account for over 50% of the reported CH₄ emissions and the top 11 account for over 75% of the reported CH₄ emissions.

As this analysis shows the reported emissions are dominated by a small sub-set of the data sets reported which implies a targeted intervention effort for emission reduction is more appropriate than a broader regulatory effort. The top reporting companies are very much aware that their operations have been unfavorably illuminated in the GHGRP and are making significant efforts to alter operations so that they will not be singled out in future reports. This is a positive outcome of the transparency provided by the GHGRP data.

Limitations of the GHGRP data: The data regarding liquids unloading in the GHGRP provides only partial coverage of the industry due to the 25,000 metric tonne CO₂e reporting threshold. EPA has estimated the extent of coverage at 85%. Reported data indicated 'Best Available Monitoring Methods' (BAMM) was used for some parameters in some data sets.

b. API/ANGA 2012 Survey Data:

Some of the conclusions that the white paper attributes to the API/ANGA survey report are not actually made in the report by the survey report authors. The white paper states:

The authors of the study made the following conclusions:

- *The 2012 GHG Inventory emissions estimates for liquids unloading were overestimated by orders of magnitude. The API/ANGA Survey data indicated a lower percentage of gas wells that vent for liquids unloading and a shorter vent duration.*
- *The emissions from liquids unloading are not specific to only conventional wells, but can be for any well depending on several technical and geological aspects of the well.*
- *Although most wells do not require liquids unloading until later in the well's productive lifetime, the timeframe for initiating liquids unloading operations varies significantly and can be early in the well's productive life span.*
- *Most of the emissions from liquids unloading operations are produced by less than 10% of the venting well population.*

These may be conclusions made by the white paper authors based on their interpretation of the API/ANGA report information and if so should be identified as such. However, there was no information provided in the API/ANGA report referenced that would provide the information necessary to reach either of the last two bulleted conclusions. Unless the white paper authors can provide the source of the conclusions attributed to the API/ANGA report and correctly attribute them, they should be removed.

The API/ANGA report also reported the percentage of wells with artificial lift (mechanical deliquification) installed (7,329 of 54,660 - 13.4%) which is relevant as these wells have no potential for venting to help unload liquids.

c. U.S. Inventory of Greenhouse Gas Sources and Sinks - 2014:

The White Paper discussion of the 2014 U.S. Inventory of Greenhouse Gas Sources and Sinks (NEI) is somewhat incomplete in that it does not discuss the limitations of the inventory estimate for liquid unloading or the difference in the ratio of wells venting for liquid unloading with and without plunger lifts from the other information sources. As Table 1 above shows, the ratio of venting wells with plunger lift and those without plunger lift in the NEI is opposite the ratio in the API/ANGA survey report, the GHGRP data, and the ICF/EDF report. This is likely due to the decimation of the API/ANGA data into NEMS regions, which yields smaller data sets for each NEMS region, with subsequent analysis at the NEMS region level to estimate activity data and emission factors. It is likely that the different ratio is an artifact of analysis of smaller data sets at the NEMS region level and hence not representative of the national well population.

d. UT Emission Measurement Study:

The White Paper discussion of this study's measurement of liquid unloading events does not appropriately stress the limitations of the study. Since only 9 well-venting instances were measured and none had plunger lift installed the unlikely representativeness of these 9 measured events should be stressed. Although the White Paper does mention the author's cautions regarding the representativeness of the measured venting events and extrapolation to a larger population, these cautions should be stressed. As the UT paper authors clearly state: *"Because the characteristics of the unloading events sampled in this work are highly variable, and because the number of events sampled is small, extrapolating the results to larger populations should be done with caution."*

Additionally, the UT study report noted that: *"In this work, sampling was performed for unloadings in which an operator manually bypasses the well's separator. Unlike automated plunger lift methods, these manual unloading events could be scheduled, allowing the study team adequate time to install measurement equipment."* This implies that wells may have initiated venting solely to enable measurement and hence may not have been "liquid loaded". If correct, the measured flow during the venting would likely be different (likely higher) than flow from the same well if the well-bore was liquid loaded.

e. ICF/EDF Report:

Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)

The White Paper representation that the ICF/EDF report based the 2011 estimate of the number of wells venting with and without plunger lifts and estimated emissions on the 2013 NEI is not consistent with the ICF/EDF report. As the following excerpts from the ICF/EDF report clearly notes, the GHGRP data for 2011 and 2012 (presumably averaged) was used to establish the "activity count" and "emission factor" for the baseline liquid unloading: *"Data reported to*

subpart W for 2011 and 2012 was used to develop new activity and emission factors for wells with liquids unloading. From the subpart W data analysis, the number of wells venting with plunger lifts was reported to be 37,643 and the number of wells venting without plunger lifts was reported to be 26,451. It was assumed that subpart W covers 85% of reporters, so the number of venting wells was increased to 44,286 and 31,113, respectively.” “The emission factors were also updated using the data reported to subpart W for 2011 and 2012. The total emissions for each venting well type (plunger lift versus non-plunger lift) were divided by the total number of reporting wells in order to obtain the new emission factors. From this analysis, the calculated emission factors were 277,000 scf/venting well for wells with plunger lifts and 163,000 scf/venting well for wells without plunger lifts.”

Also, the White Paper should clearly note that the ICF/EDF baseline estimates for venting of wells for liquid unloading does not represent any “new” information and is simply an analysis and “gross-up” of the GHGRP data.

Charge Question 2

Is there further information available on VOC or methane emissions from the various liquids unloading practices and technologies described in this paper?

API provided supplemental material and analysis from the 2012 report “Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012)” to the EPA National Inventory team. This information provided additional detail, analysis, and derivation of emission factors for both plunger and non-plunger equipped wells. The following table shows a summary of the information furnished that was not reviewed or included in this report.

Calculated national # wells w/plunger lift that vent for unloading	36,806	Wells
Calculated national # wells w/o plunger lift that vent for unloading	28,863	Wells
Calculated # vents for wells w/plunger lift	344	vents/venting well-yr
Calculated # vents for wells w/o plunger lift	33	vents/venting well-yr

Emission Factor per vent

Calculated EF: gas emissions per unloading vent for wells w/plunger lift	1,005	scf gas/unloading vent
Calculated EF: gas emissions per unloading vent for wells w/o plunger lift	9,336	scf gas/unloading vent

Emission Factor per well

Calculated EF: gas emissions per well for venting wells w/plunger lift	345,343	scf gas/venting well-yr
Calculated EF: gas emissions per well for venting wells w/o plunger lift	304,048	scf gas/venting well-yr

It is important to note that the total number of wells using a venting technique to assist in unloading liquids was 65,669 wells. If there are 504,000 gas wells then this number is 13% of the total. Any administrative or regulatory action should be focused at this small subset of the wells rather than being a broad-brush approach to burden the entire population of gas wells with restrictions that are unnecessary.

Additional information providing background on well-bore liquids loading, techniques and tools used to manage liquid loading, and the role of venting to aid liquids unloading can be found in the Subpart OOOO docket. The information in the Subpart OOOO docket should be accessed and characterized in the White Paper. A massive amount of information regarding well-bore liquids loading, management of well-bore liquids, and deliquification technologies and techniques is available in the oil and gas industry technical literature. A good place to start accessing this information is Gas Well Deliquification portion of the “Artificial Lift R&D Council (ALRDC)” website at <http://www.alrdc.com>.

Limited information regarding emissions from well venting to aid liquids unloading and the reductions achieved by actions/projects to reduce venting are available in the Natural Gas Star archives of Technology Transfer Workshops and Annual Implementation Workshops can be found at the EPA’s Natural Gas Star website <http://www.epa.gov/gasstar/workshops>. For example, several updates to the BP “Smart Automation” well unloading management, referenced in the white paper, have been presented with the latest in February of 2014.

Charge Question 3

Please comment on the types of wells that have the highest tendency to develop liquids loading. It is the EPA’s understanding that liquids loading becomes more likely as wells age and well pressure declines. Is this only a problem for wells further down their decline curve or can wells develop liquids loading problems relatively quickly under certain situations? Are certain wells (or wells in certain basins) more prone to developing liquids loading problems, such as hydraulically fractured wells versus conventional wells or horizontal wells versus vertical wells?

EPA’s understanding is somewhat correct in that older wells do have a greater tendency to develop liquid loading problems due to decreased production rate - not pressure. The physical model that describes how free-flowing wells (including wells venting without plungers) is a “drag model” that describes the physical action of high-velocity gas flow dragging liquid packets at the no-flow boundary between the liquid and the gas. In this model, pressure is a secondary effect and the action of the gas on the liquid is dominated by the gas velocity. A more correct understanding would be that lower production rate wells have a greater susceptibility to liquid loading due to decreased velocity - which often occurs in older wells as production rate declines. However, liquid loading issues can and do occur in newer wells with inadequate velocity to lift the amount of liquids produced by the well. Absent a plunger-lift barrier between the well-bore liquid load and the formation, the formation pressure is not the relevant characteristic leading to liquid loading.

Whether a well is hydraulically fractured or completed with other stimulation technique has nothing to do with when it might experience problematic liquids loading. Whether a well is vertical or horizontal is also not relevant to when a well may experience problematic liquid

loading. One could speculate that to the extent that hydraulically fracturing a well or drilling a horizontal section raises the production rate from a well then such wells would have fewer tendencies to experience problematic liquid loading until later in their life-cycle. For example:

- A well making 3 MMSCF/day may begin experiencing liquids loading in certain high liquids production situations—these liquid loading problems will normally be addressed by adding a mechanical pump, not plungers or venting.
- A well making 50 MSCF/day experiencing liquids loading will typically be evaluated for lower cost deliquification methods like adding a plunger or putting the well on intermittent (shut-in) or vent cycles. Onset of liquids-loading is a function of a very wide range of physical parameters and appropriate responses require evaluation of all of those parameters.

Charge Question 4

Did this paper capture the full range of feasible liquids unloading technologies and their associated emissions? Please comment on the costs of these technologies. Please comment on the emission reductions achieved by these technologies. How does the well's life cycle affect the applicability of these technologies?

Prior to discussion of individual technologies, techniques, and practices to manage well-bore liquids and venting to aid deliquification, the White Paper should acknowledge the complexity of the issues. Dealing with liquids-loading issues is a very complex mix of engineering and economics applied to an individual well. The appropriate approach to managing well-bore liquids in an individual well will likely change as the well progresses through its life-cycle. Attempting to describe the applicability of individual techniques to the wide range of U.S. gas wells is not an appropriate approach and runs the risk of severely constraining innovation. Well deliquification is a fundamental challenge for continued production from the majority of US gas wells and the proportion is expected to grow with new growth concentrated in non-traditional gas reservoirs such as shales, coal-beds, and tight-gas sands which are susceptible to liquid loading. Managing wellbore liquids loading is a primary focus for production engineers and operations teams. A very large amount of industry focus, research, and attention is applied to gas-well deliquification with innovation and research continually underway. Research and work regarding managing well-bore liquids aims to both optimize and improve existing techniques along with developing entirely new types of systems. The flexibility to pilot some of these ideas/developments must be preserved – even if they ultimately do not succeed.

a. AVAILABLE LIQUIDS UNLOADING EMISSIONS MITIGATION TECHNIQUES

The introductory paragraphs in this section of the White Paper illustrates misconceptions in the understanding of liquid loading of wells, venting to aid in unloading liquids, and approaches to minimize venting.

As previously noted above, the statement that

As the bottom well pressure approaches reservoir shut-in pressure, gas flow slows and liquids accumulate at the bottom of the tubing.

is not correct. “Reservoir shut-in pressure” has no meaning in relation to liquid loading of well-bores. What is important is the flow rate into the well-bore and the flow velocity up the tubing in the well.

The introduction of the term “blowdown” as an analogue to venting of wells to aid in liquid unloading is simply unnecessary and may be confusing to some readers. In the subsequent discussion, the White Paper discusses “blowdown” as a stand-alone approach to unloading well-bore liquids. While this may be correct in some instances, venting of wells to aid in unloading well-bore liquids is common in conjunction with some other approaches discussed - such as plunger lifts.

The statement that:

These technologies can reduce the need for liquids unloading operations or result in the capture of gas from liquids unloading operations.

is incorrect in its understanding. What the technologies subsequently discussed can do is reduce the need for or practice of **venting** to aid in unloading liquids - unloading of well-bore liquids still must be accomplished. Also, dependent on the technique applied, gas not vented may be retained in the reservoir or produced - it is not “*captured from liquid unloading operations.*”

b. Section 3.1 “Liquid Removal Technologies”

This section of the White Paper has several errors, misunderstandings, and omissions.

There is no discussion of the limitations of the Natural Gas STAR program documents and partner presentations. The White Paper should be very clear that the Natural Gas STAR Lessons Learned documents are not peer reviewed, generally represent a compilation of information furnished by Natural Gas Star partners and studies commissioned by EPA, are generally compiled and written by an EPA contractor, and have not been rigorously reviewed by industry or other experts in the subject matter. Partner presentations are similar in that they have not been rigorously reviewed and typically describe an individual project or application of a technology or technique rather than a broad application. For technology and practice sharing the level of review and scrutiny was appropriate and the Lessons Learned, Partner Reported Opportunities, and Partner Presentation documents are useful and valuable. However, extrapolating these Natural Gas Star documents to the broad US population of wells and compiling the information to inform public policy, as the White Paper purports to do, demands a higher level of review and validation of the underlying information - which is lacking in the White Paper.

Some of the actions listed in the White Paper that the Natural Gas Star program reports are taken when liquids unloading occur are not correct. For instance:

Shutting in the well to allow the bottom hole pressure to increase, and then venting the well to the atmosphere (well blowdown),

This statement is not correct. Wells may be vented without a shut-in cycle. A shut-in cycle can temporarily increase bottom-hole pressure near the well-bore and, more importantly, well inflow and production rate which will increase flow velocity when the well is flowed - either to production or atmosphere. Wells are often shut-in, a technique known as intermitting, either

manually or more commonly via automation to temporarily increase well inflow and production rate and enable liquid lifting while producing into a collection system.

| *Swabbing the well to remove accumulated fluids,*

The White Paper presents swabbing as a technique commonly used to manage well-bore liquid loading. In practice, swabbing is a remedial treatment with a rig or wire-line unit that is used only when a well will not respond to other techniques to remove the liquids from the well-bore and restore flow. It is expensive and hence not commonly used to manage liquid loading on a frequent basis.

The White Paper does not discuss “intermitting” as a technique to manage liquid loading of well-bores and potentially reduce venting. Intermitting is a technique where producing periods are interspersed with shut-in periods to allow the reservoir to “refill” the area around the well-bore that has been partially depleted during the producing period. The shut-in periods enable temporarily higher production rates and can enable velocities sufficient to lift liquids while producing rather than venting.

The discussion of “smart automation” techniques, either coupled with plunger lifts or on wells without plunger lifts, in the White Paper is incomplete. The key to managing well-bore liquid loading while minimizing venting is understanding, managing, and using reservoir energy not installing or running plunger lift systems or other techniques to aid well-bore liquid management. One approach to smart automation systems (but not the only possible approach) works by optimizing the management of individual well flowing and shut-in times to enable unloading of well-bore liquids without venting. This approach is applicable to both wells with plunger lifts and wells without plunger lifts although wells with plunger lifts have more variables for the system to manipulate. The basic concept is: “The reservoir does not quit working when a well is shut-in”. Producing a well creates a zone of lower pressure and lower inflow capacity near the well-bore. During shut-in, when the well is not flowing, the reservoir will continue to flow into the depleted zone and partially replenish the reservoir. When a well starts flowing after a shut-in period it will temporarily have higher inflow (production) rate (often termed flush production) and higher pressure available. The higher production rate may provide adequate velocity to lift liquids while producing in the absence of a plunger lift and the higher pressure may provide adequate energy to lift a plunger and its load while producing without the need for venting. Although the potential benefits of such an approach are briefly discussed in the White Paper, much more emphasis and discussion should be devoted to this subject.

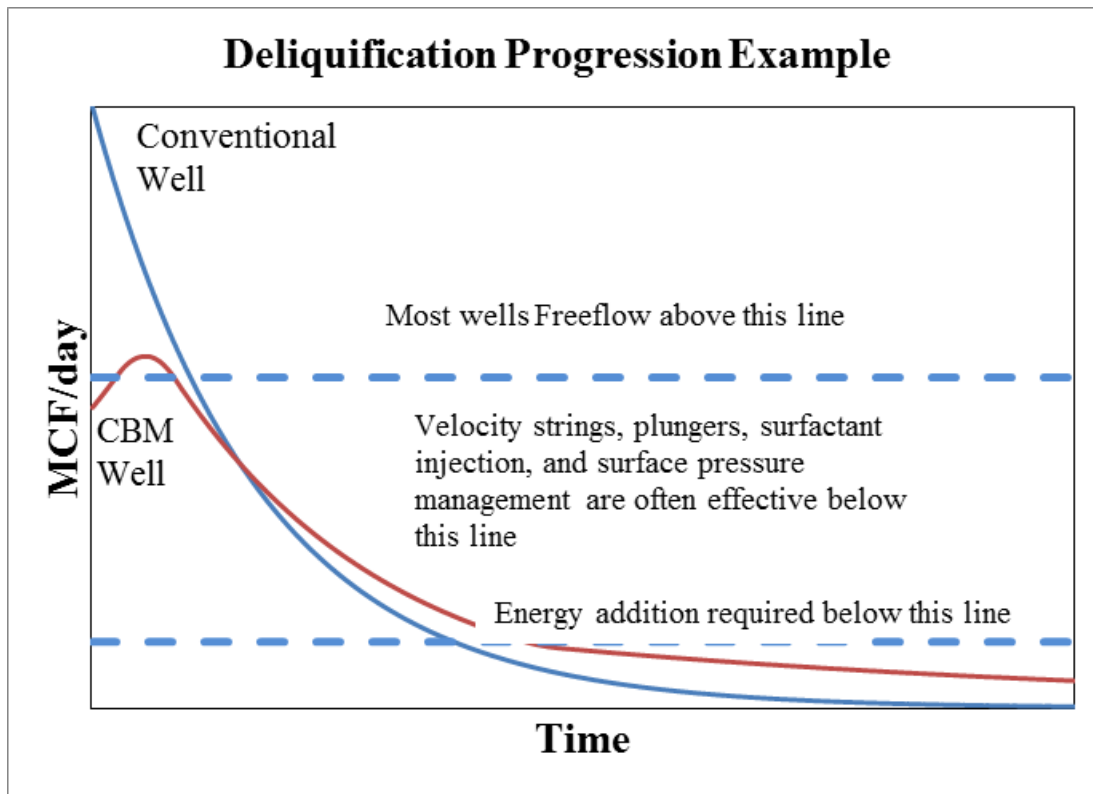
The BP “smart automation” project discussed in the documents referenced in the White Paper (British Petroleum (BP) 2006; U.S. EPA 2006a; and U.S. EPA 2011) provides an excellent case study example of the application of understanding and optimizing reservoir energy management to sharply minimize venting associated with liquid unloading. However, the BP project is somewhat mischaracterized in both U.S. EPA 2006a and U.S. EPA 2011 as a project to install plunger lift systems in conjunction with “smart automation”. The actual nature and success of the project was to optimize the frequency and duration of shut-in times on individual wells and plunger cycle timing on wells with plungers through the use of automation that learned the performance of

each well and then optimized the cycle parameters for that well – i.e. “smart automation”. This was and is a project about managing reservoir energy not about installing or running plunger lift systems. About half of the wells which were venting were plunger equipped and about half were not plunger equipped. Both plunger equipped and non-plunger wells were previously vented in order to generate the flow or pressure differential necessary to lift liquids. Also, the references to this project in the White Paper are incomplete. Updates regarding this project were presented at the 2007 Natural Gas Star Annual Implementation Workshop and several times since with the latest at the Denver, CO and Park City, UT Technology Transfer workshops in 2014.

Splitting the techniques used to manage liquid loading into “primary” and “remedial” technologies in the White Paper is not useful from the standpoint of improving understanding regarding minimizing venting to assist deliquification. A more appropriate approach would be to split the technologies into those that rely on reservoir energy for unloading liquids and those that add energy to the well-bore to unload liquids. Plunger lift, velocity tubing, intermitting, soap/surfactant injection, and reducing surface pressure via de-bottlenecking or compression all rely on reservoir energy. Down-hole pumps, of various types, and gas-lift add energy to the reservoir fluids. Conceptualizing technologies/techniques in this manner enables consideration of approaches to minimize venting at each stage of a wells life-cycle and in conjunction with each technology/technique used.

Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore. In the early stage of a well’s life many (but by no means all) wells can flow freely and with sufficient velocity to avoid liquid loading problems. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquid-loading begins to be a problem and one of a portfolio of technologies or techniques will be used to help lift liquids using the reservoir’s energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoir’s energy is not sufficient to lift liquids and mechanical lift energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The following figure shows a generalized well life-cycle curve with these different stages of a wells life illustrated.



To address this normal well/reservoir depletion and assist liquid lift a number of techniques are used – dependent on the well configuration, reservoir properties, well depth, and surface equipment and collection system. The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology-selection requires a thorough understanding of the conditions that a reservoir is flowing into, the reservoir's sensitivity to backpressure and the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology. Operators must have the flexibility to choose the most appropriate and cost effective approach for each individual well/reservoir/age/production combination and the regulatory certainty to underpin continued investment. Minimizing venting associated with liquid unloading is part of this ongoing evaluation.

c. Costs

Stating generic costs/cost-ranges and/or economics for any of the technologies or techniques discussed is fraught with difficulty and error. Costs and economics are as variable as the wells and reservoirs they are applied to and any problems or difficulties encountered. There are documented cases where installing a plunger in a well has cost several hundreds of thousands of dollars when other problems were encountered upon pulling the tubing to set a profile nipple for a bumper spring. Certainly such costs are germane to the discussion since it is a possible outcome of any decision to work on a well. There is simply no way to state generically where most wells are within their performance lifecycle, how they will respond to a technique/technology, or what the costs and economics of application will be. One well may be economic at 20 MSCF/day while another might be plugged when the rate reaches 150 MSCF/day. The difference is a complex mixture of reservoir performance, market-price differentials, level of capitalization, and operating

costs. These variations are what drive evaluation of individual wells for the appropriate selection and application of technologies/techniques to manage liquid loading or a decision to plug a well that can no longer support the costs of deliquification. Retaining the flexibility to make individual well-appropriate technology-decisions is fundamental to the continued economic production of a great many gas wells in the U.S.

d. Section 3.1.1 Plunger Lifts:

The assertion in the White Paper that installation of plunger lift systems is an emission (venting) control technique is not correct, not supported by the emission data, and not underpinned by a logical or technical analysis in the White Paper. Plunger lifts are a valuable, effective and commonly used methodology/tool to assist in managing well-bore liquid loading. Plunger lifts do increase the efficiency of liquids removal from wells by the reservoir energy and hence do help maintain or increase production. However, the efficacy of plunger lifts in reducing venting of wells deliquification and emissions is completely dependent on how they are operated. As the API/ANGA survey report, the GHGRP data, the U.S. Emission Inventory, and the ICF/EDF report reanalysis of the GHGRP data shows, venting wells with plungers have higher emissions per well than venting wells without plunger lifts. Despite the API/ANGA survey report estimate that only about 36% of U.S. gas wells are equipped with plunger lifts (of which only a subset vent), venting of wells with plunger lifts constitute the majority of venting wells and emissions. Wells with plunger lift systems comprised ~55% of the more than 58,000 wells reported as venting for liquids unloading into the GHGRP for 2012. From an emission perspective, wells with plunger lift systems accounted for about 72% of the GHGRP reported emissions from well venting for liquids unloading. The GHGRP reported data is broadly equivalent to that reported from the API/ANGA survey. With the API/ANGA survey outcome of about 36% of the well population being equipped with plunger lift systems yet responsible for over 50% of the venting wells and 70% of the emissions, **the efficacy of plunger lift systems as an emission control measure is clearly not supported by the data.** However, with advanced well liquids unloading management (management of reservoir energy), large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made.

e. Table 3.1 Plunger Lift Review Comments:

- The statement in the Applicability column that

“Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system”(U.S. EPA, 2006b).”

is incorrect. By definition, plunger lift systems are dependent on reservoir energy, specifically downhole pressure, to lift the plunger and the water/fluid load in the well-bore. Adequate differential pressure must exist between the reservoir pressure and the sum of liquid column hydrostatic pressure, flowing friction pressure loss, surface equipment pressure loss, and collection system back-pressure in order for a plunger to return to surface with the liquid load. Adequate differential pressure may be generated by using shut-in cycles to increase downhole pressure or by using venting cycles to remove surface and collection system back-pressure. The key to minimizing venting associated with plunger operation lies in how you

achieve adequate differential pressure to enable a plunger to lift into the producing system rather than venting to atmosphere.

- Cost ranges: The cost ranges in Table 3.1 appear to be copied directly from the underlying documents cited and do not appear to be updated to current dollars. This significant oversight should be corrected in the White Paper. Also, the costs and economics extracted from the underlying documents were predominantly based on Gas Star partner reports and likely reflected installations of plunger lifts that had already been determined to be appropriate for the individual wells where they were installed based on a well-by-well evaluation by the companies making the installations. The resultant cost and economic profile would likely be very different than installations done on a basis different than well-by-well evaluation.
- The statement in the “Efficacy and Prevalence” column of the Table 3.1 plunger lift section that *“The EPA has learned plunger lift systems rely on manual, onsite adjustments.”* is not uniformly or even mostly accurate. A large percentage of plunger lift installations are controlled with automated plunger control systems rather than manually operated. Increasingly, these systems incorporate the capability to identify problems and make immediate adjustments. Techniques with telemetry, electronic data collection, and troubleshooting software continue to improve plunger-lift performance and ease of use. A cursory review of plunger vendor websites show that most/all offer advanced plunge control systems that optimize plunger efficiency. Several links to examples are:

<http://www.weatherford.com/Products/Production/PlungerLift/>

http://www.pcslift.com/plungerlift/plunger_products.html

http://www.pcslift.com/PDFs/PCSFerguson_PLMgr.pdf

- Information regarding the prevalence of plunger lifts is missing from Table 3.1. As the API/ANGA survey report noted, about 36% of the U.S. gas wells are equipped with plunger lifts.

f. Section 3.1.1 - Plunger Lift Narrative Review Comments:

The introductory paragraph of this section is incomplete and somewhat misleading.

“Based on our assessment of the data, a plunger lift system for liquids unloading is capable of performing liquids unloading with little or no emissions. The level of emissions depends on how the plunger lift system is operated, specifically, whether gas is directed to the sales line or vented to the atmosphere. There may be potential for improved production and emissions reduction when paired with a smart well automation that optimizes production and reduces product losses to the atmosphere.”

As discussed above, the key to minimizing venting of wells equipped with plunger lifts is how the differential pressure necessary to lift a plunger and its load is achieved. If this is accomplished through vent cycles then venting emissions are likely to be high for a well equipped with a plunger. Conversely, if this is accomplished by using shut-in cycles to manage the reservoir pressure build-up then venting emissions are likely to be much lower. Using a plunger control system, “smart automation”, system that optimizes the operation of the plunger on an individual well to achieve maximum unloading/production and minimum venting/emissions is likely to

reduce venting/emissions to just instances where overloading occurs due to system malfunctions or high reservoir liquid/water production surges. Differences in approach to operation of plunger lift equipped wells are mostly due to differences in the approach/philosophy that operators take to managing reservoir energy and somewhat due to differences in reservoir characteristics.

The description of a plunger lift system should clearly note that this is an example only and that other configurations are common. Also, the White Paper should describe the broad range of plunger types and configurations available along with noting the significant amount of ongoing development and research devoted to improving plunger lifts and their operation. For example, continuous-run flow-through plungers are available that have a higher liquid volume lift capacity and are appropriate for some wells. Also recently available are flexible plungers designed for use in wells with quite high deviation from vertical - which is becoming more common with multi-well pad development. Additionally, Figure 3-1 page 21 shows a “gas lift valve” on the bottom of the tubing. This valve is not part of the required bottomhole assembly for plunger operation.

As discussed above in the Table 3.1 comments, the costs and economics of plunger lift installations appear to be extracted directly from the underlying documents referenced, are not updated to current dollars, and are predominantly based on costs and benefits reported by Natural Gas Star partners that have been compiled by an EPA contractor in the underlying documents. These costs are seriously outdated and need to be updated using an escalator for oil and gas equipment and labor which has been higher than the consumer price index (CPI) since 2000. It is strongly suggested that EPA engage industry operators and plunger lift suppliers in a survey to gather updated costs.

The White Paper summary of the ICF/EDF report fails to highlight that the 95% reduction in venting, that drives the economics of plunger lift installation summarized, is based on a simply asserted reduction that is not underpinned by any analysis in the ICF/EDF report. The White Paper does not analyze or validate this assertion. The ICF/EDF capital and operating cost assumptions summarized in the White Paper have similar issues.

g. Section 3.1.1 - Artificial Lift Systems:

The discussion of artificial lift systems in both Table 3.1 and the White Paper narrative omits several technologies/techniques and pump types used in mechanical deliquification (artificial lift).

There is no mention of gas lift, which involves injection of higher pressure gas down the casing-to-tubing annulus in order to increase the flow up the tubing thereby increasing the velocity and capacity to lift liquids. Gas lift typically requires additional compression and piping at the surface which requires either electricity to drive compressors or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.

The discussion of pumps focus solely on beam pumps (also termed rod pumps, beam lift pumps, and pumpjacks in the White Paper) and omits progressing cavity pumps and electric submersible pumps. Although not as prevalent as beam pumps, these pump types are used for deliquification of gas wells. Also, omitted from the White Paper is any discussion of linear pumps, both coupled with a rod pump (replacing the walking beam), and in downhole applications. Considerable

development and research is being applied to pump technology and linear pumps are one fairly recent outcome with ongoing improvement expected.

The reference to “downhole separator pumps” in Table 3.1 is not recognized as a technology that exists. If a valid technology, the White Paper should provide a detailed description of this technology and the nature and extent of its use.

The costs shown for artificial lift installations have the same problems as costs shown for other technologies/techniques. They appear to have been extracted directly from the underlying sources referenced and have not been updated to current dollars and appear to be based on limited reports by Natural Gas Star partners in the underlying documents. Also, costs are very well-specific, company specific, and technology specific. Generalizing these costs is not appropriate.

Omitted from Table 3.1 is information from the API/ANGA survey report that 13.4% of the wells reported in the survey have some form of mechanical deliquification (artificial lift) installed. This is important and should be included. The statement in Table 3.1 that *“The EPA does not have information on the prevalence of this technology in the field.”* is incorrect.

h. Section 3.1.1 - Velocity Tubing:

The discussion of velocity tubing in Table 3.1 and the narrative omits any discussion of the trade-off between increased potential velocity with a smaller x-section of flow and increased flowing friction inherent in smaller diameter tubing which inhibits flow and hence velocity. In practice this trade-off limits the practical minimum diameter of velocity strings to about 1 - 1.5 inches. Although a review of the underlying documents referenced by the White Paper is beyond the scope of these comments, the statement in U.S. EPA 2011 that *“Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches.”* is incorrect and needs to be corrected.

The excerpt from U.S. EPA 2011 in Table 3.1 that notes *“Seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream (U.S. EPA, 2011).* is based on an unsupported assertion in U.S. EPA 2011 that makes vague reference to unidentified “studies” reaching this conclusion. This reference should be removed from the White Paper unless substantiated.

The range of flow rates or life-cycle stages where velocity tubing may be applied in both Table 3.1 and the narrative discussion are simply not correct. Any tubing string placed within the production casing can be thought of as a “velocity string”. The well operator is using velocity (at the price of increased friction drop) to keep the gas flow above some “critical value” that is required to allow the gas to reliably lift the liquid. It is correct that smaller diameter tubing strings are used to increase velocity and the ability of gas to lift the liquid. However, the range of production rates and water loading where smaller diameter tubing may be a benefit is considerably broader than represented in the White Paper. Candidate wells and the appropriate tubing diameter are selected based on a modeled calculation of “critical velocity” based on the physics of fluid flow and flowing friction. That critical velocity value is not 1000 ft/min (16.67 ft/sec), as stated in the White Paper, except in the rarest of coincidences.

The cost and economic data presented in the White Paper appear to have been extracted directly from the underlying documents referenced, are not updated to current dollars and should be

revised. Also, similar to other costs and benefits noted in the White Paper, they appear to be based on self-selected reports from Natural Gas Star partners on successful installations of velocity strings and are not likely to reflect the performance/benefits of installation of velocity strings where their application is not based on well-by-well evaluation and selection.

The statement in Table 3.1 that velocity strings are “Considered to be a no emission solution.” is incorrect. It is not uncommon for wells with smaller diameter velocity tubing strings to be vented to aid in liquid unloading. The GHGRP well venting data using Method 1 (which represents a small portion of total reports) for 2011 and 2012 contain multiple data sets where the tubing size selection is <1” although this selection is not always consistent with the average tubing size shown.

i. Section 3.1.1 - Foaming Agents:

The discussion of soap/surfactant use in Table 3.1 is not consistent with the discussion in the narrative and is not correct. The Table 3.1 discussion focus on injection of soap/surfactants omits instances where wells are configured to gravity feed surfactants along with instances where “soap sticks” are simply “dropped” down the casing-tubing annulus. The discussion of how a soap/water solution generates foaming is an oversimplification of the physics involved which are dependent on turbulence for foam generation. In general, the successful use of surfactants is more than the low-tech solution implied by the table.

The Table 3.1 representation of foaming agents as a “no emission solution” is not correct. It is not uncommon for venting to be used in conjunction with soap/surfactant use to unload liquids.

The cost and economic data presented in the White Paper appear to have been extracted directly from the underlying documents referenced, are not updated to current dollars and should be revised. Also, similar to other costs and benefits noted in the White Paper, they appear to be based on self-selected reports from Natural Gas Star partners on successful use of soap/surfactants and are not likely to reflect the performance/benefits of soap/surfactants where their application is not based on well-by-well evaluation and selection.

Charge Question 5

Please provide any data or information you are aware of regarding the prevalence of these technologies in the field.

Data regarding the prevalence of plunger lift installations is presented in the API/ANGA survey report where 36% of the wells reported (21,500 of 59,648 wells) having plunger lifts installed. Projecting this to a national population for 2010 the API/ANGA report estimated about 174,743 wells with plunger lift in 2010.

Data regarding the prevalence of mechanical deliquification (artificial lift) is presented in the API/ ANGA survey report where 13.4% of the wells reported (7,993 wells) having some form of mechanical deliquification installed. Projecting this to a national population for 2010 the API/ANGA result implies about 68,000 wells with mechanical deliquification installed in 2010.

Charge Question 6

In general, please comment on the ability of plunger lift systems to perform liquids unloading without any air emissions. Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where it is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

Plungers operate by providing a mechanical barrier between the liquid column in a well-bore and the reservoir gas/energy that is used to lift the plunger and liquid load to the surface. Plungers depend on adequate differential pressure to lift liquids and do increase the efficiency of using reservoir energy vs. depending on velocity to drag liquids. A plunger's ability to rise is defined by six physical parameters :

- Weight of the plunger
- Mechanical friction of the plunger against the tubing walls
- Fluid friction against the tubing walls
- Weight of the liquid being lifted
- Surface equipment pressure drop and collection system/surface backpressure
- Formation/reservoir pressure available for lift

The first three parameters have a reasonably consistent and predictable magnitude. The fourth parameter is quite variable. If the total liquid weight increases, the balance between bottom-hole pressure and flowing tubing-head pressure can fall to zero and lose the driving force for the system. At that point operators may remove surface restrictions and gathering-system pressure from the equation by venting the well to re-establish the necessary differential pressure to run the system. Other operators may rely on shut-in periods to build pressure in the near well reservoir. Other operators may install well-site compression to allow the use of mechanical horsepower to remove the backpressure from the process.

With advanced reservoir-energy management and optimized well-liquids unloading management, large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made. However, the need to vent will still occur. Even with advanced plunger lift systems and advanced control systems for both plunger lift equipped wells, there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading (height of water column) in the well bore which can be caused by natural variation in reservoir flow or system failures/malfunctions.

As the emission data sources uniformly show, venting of wells equipped with plunger lifts accounts for more emissions overall and on a per-venting-well basis than emissions from venting of wells not equipped with plunger lifts. The counterfactual interpretation of the data, which the ICF/EDF paper does, is purely conjecture and should be noted as such.

Charge Question 7

Based on anecdotal experience provided by industry and vendors, the blowdown of a well removes about 15% of the liquid, while a plunger lift removes up to 100% (BP,

2006). Please discuss the efficacy of plunger lifts at removing liquids from wells and the conditions that may limit the efficacy.

The representation in this question that the BP presentation referenced claims 100% liquid removal (presumably of the column of liquid in the well-bore above the plunger) is not correct. The BP presentation made no representations regarding the percent of liquid (again presumably the column of liquid in the well-bore above the plunger) removal by a plunger.

In practice, plunger lifts are designed with clearance between the plunger and the tubing walls to enable gravity free-fall down a well and minimize plunger friction during travel to the surface. Due to this clearance, some gas leaks upwards past a plunger and some liquid “slips” past the plunger or plates out against the tubing wall and subsequently falls back into the well. The amount of liquid that “slips” or plates out against the tubing walls and subsequently falls back into the well is variable and depends on several factors.

Charge Question 8

Please comment on the pros and cons of installing a plunger lift system during initial well construction versus later in the well’s life. Are there cost savings associated with installing the plunger lift system during initial well construction?

There is likely no instance where installation of a plunger lift system during initial well construction would be beneficial. Many wells will never be a candidate for plunger lift use and installation of a plunger lift system would simply be a complete waste of money. Most wells that eventually do experience liquids loading and are candidates for plunger lifts will not reach that point until after many years of free-flowing production. Installing a plunger lift system at initial well construction would unnecessarily decrease capital efficiency. Practically, in the time that a well is free-flowing, it is likely that the well may be worked on 3-5 times, each time it is worked on all of the plunger equipment would be removed to facilitate pulling the tubing. After sitting in a well for many years, it would be rare for components like profile nipples, bumper springs, and lubricators to be in a condition that would allow their re-installation so putting this equipment on new wells assures that it will be discarded long before it could ever be put in service. It is also unlikely that a plunger lift system installed at initial well construction would be functional if and when it was called on to operate after many years of sitting in a well. For high flowing wellhead pressure wells, such as the Marcellus Shale, lubricators for plungers are not available with pressure ratings high enough for application. For high production rate wells, the tubing sizes are larger to accommodate the flow. Tubing plungers for 4.5 inch tubing, which is common in high rate wells, are not available - nor are they needed due to the high flow rates and velocities. Additionally, the plunger equipment in a well can fail and cause problems that would require additional expenditures to correct.

Installing a plunger lift system at the time of initial well construction would also “lock-in” technology at the time of installation. Given the tremendous amount of research, development and focus being applied to deliquification of gas wells and the amount of progress being made this is not advisable.

The concept of installing a plunger lift system at initial well construction indicates a lack of understanding of wells, well life-cycle, liquid loading, and efficient use of resources.

Charge Question 9

Please comment on the pros and cons of installing a “smart” automation system as part of a plunger lift system. Do these technologies, in combination with customized control software, improve performance and reduce emissions?

To the extent that advanced (smart) automation of well operation and liquid loading management improves the management of reservoir energy, such use is likely to reduce, but not eliminate, the need for venting to aid liquid unloading. This can be beneficial for both wells equipped with plunger lifts and wells without plungers installed.

However, these systems are expensive, require customization to the area and reservoir where they are being deployed, and require highly skilled personnel to maintain, calibrate, and operate. As the BP “smart automation” project, referenced in the White Paper, shows these types of installations can be difficult and may take years of concerted effort to achieve the desired outcomes. They are not a “silver bullet” answer to reduce venting for liquid unloading but are another valuable tool to be used as appropriate.

Charge Question 10

Please comment on the feasibility of the use of artificial lift systems during liquids unloading operations. Please be specific to the types of wells where artificial lift systems are feasible, as well as what situations or well characteristics discourage the use of artificial lift systems. Are there standard criteria that apply?

This question indicates a misunderstanding of venting to aid liquid unloading, which is the activity that results in emissions, and the elimination of any benefit of venting when artificial lift is installed. As discussed above, mechanical deliquification (artificial lift) is the addition of energy, in the form of a pump or gas lift, to a well-bore to enable liquid removal. It is employed when the reservoir energy in a well is not sufficient to use other, techniques to aid in liquid removal. Once applied, venting a well provides no benefit and will not occur. However, installation of pumps or gas lift is expensive and the expected production of many marginal wells will not support the investment necessary.

Pumps in gas well deliquification applications struggle to cope with the typically low liquid volumes, variable liquid volumes, and damage caused by cavitation and “gas-locking” of the pumps. Many techniques and approaches are employed in an attempt to deal with this problem with varying degrees of success. Ongoing research and development of gas well deliquification specific approaches and products is making progress on these problems.

Although gas lift is applied to gas well deliquification, it is far less effective on gas wells than when applied to oil wells due to water having little ability to absorb natural gas which serves lighten the specific gravity of the mixed fluid in a well bore. Gas lift typically requires additional

compression and piping at the surface which requires either electricity or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.

Beam pumps require a surface power unit and continuous rods from the surface to the bottom-hole plunger pump. While more forgiving of low liquid production volumes than submersible pumps or progressing cavity pumps, beam pumps are not very optimum for deviated well-bores such as those on multi-well pads (done to reduce surface disturbance). In a deviated well-bore, the rods will tend to rub against the tubing/casing and cause wear and failure of either the rods and/or the tubing/casing. Unless electricity is available, the surface power unit must be a gas fired reciprocating engine which adds significant emissions, complexity, reliability concerns, and operating costs.

It is important to understand the distinction between applying a mechanical deliquification technology to a gas well to remove liquids from interfering with gas production and artificial lift in the classic sense of lifting a commercial product, typically oil, to the surface. The economics and economic drivers are entirely different between the two. When the expected production from a gas well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned. Requiring the installation of mechanical deliquification technology (artificial lift) would cause many marginal U.S. gas wells to be abandoned. This would likely disproportionately impact smaller producers since they typically have portfolios of smaller more marginal wells.

There are no “standard criteria” that apply across reservoirs, wells, and companies.

Charge Question 11

The EPA is aware that in areas where the produced gas has a high H₂S concentration combustion devices/flares are used during liquids unloading operations to control vented emissions as a safety precaution. However, the EPA is not aware of any instances where combustion devices/flares are used during liquids unloading operations to reduce VOC or methane emissions. Please comment on the feasibility of the use of combustion devices/flares during liquids unloading operations. Please be specific to the types of wells where combustion devices/flares are feasible. Are there operational or technical situations where combustion devices/flares could not be used?

API is not aware of any instances where flares or other combustion devices are used during liquids unloading operations. In 2012, 58,663 discrete wells were reported into the GHGRP as vented for liquids unloading. Grossing this up, using EPA’s estimate of 85% coverage under Subpart W, yields just over 69,000 individual wells vented to unload liquids in 2012. Flaring of gas during liquids unloading would necessitate separation of the liquids from the well stream in a separator or flare knock-out drum. Backpressure, sufficient to unload liquids from the separator to a storage tank, would need to be held against the well/separator which would directly reduce the differential pressure gained by routing to atmosphere and perhaps inhibit unloading. Due to the potential flow rate and Btu demand, flares would need to be dedicated to liquids unloading and be moderate size

(~20 MMBtu/hr) rated. Liquids unloading flares would need either continuous pilots (for infrequent use) or electronic igniters powered by solar in most instances. Also, well-sites would need to be “re-piped” to route from the separator to the dedicated well unloading flare. Besides the technical difficulties dealing with the intermittent and surging flow characteristic of venting for liquids unloading, the changing velocities during an unloading and the problems of ensuring ignition for a sporadically used flare, the cost would be prohibitive. Multiplying the estimated total installed cost of \$100k per flare times the number of wells vented for liquid unloading in 2012, the cost would easily be *billions* of dollars. There are much more cost effective methodologies to reduce liquids unloading without the emissions and visual impact associated with flaring.

Combustors on H₂S wells are truly a special case. Hydrogen sulfide presents an acute safety risk both to employees and to the general public. Understanding and designing for that risk is part of the economic evaluation made prior to producing the well. Combustors on these wells regularly require electricity to drive blowers to ensure that the combustion process is stoichiometric and unburned process gas is prevented to the maximum extent possible. Igniters/pilots that are robust and redundant technologies are provided. In short these devices are very expensive to acquire and operate. Requirements for this technology on sweet-gas wells would make the vent/plug decision much easier and many wells with considerable recoverable gas in place would be abandoned rather than installing flare/combustion technology.

Charge Question 12

Given that liquids unloading may only be required intermittently at many wells, is the use of a mobile combustion device/flare feasible and potentially less costly than a permanent combustion device/flare?

It is very unlikely that portable flare equipment, which tends to be more expensive on a unit basis than stationary flares, would be feasible for use with respect to venting for liquids unloading. Moving a flare to a location, hooking it up to a vent line, testing the integrity of the system, and then ensuring a pilot light each time a well was to be vented would take considerable time and cost. Given the sheer number of wells that vent for liquids unloading, about 69,000 in 2012 based on the GHGRP data, coupled with the number of venting instances, 4,524,802 venting events for Method 1 reported into the GHGRP plus the yet to be reported instances for Methods 2 & 3, the costs and logistics to use this approach would far outweigh any benefits.

Charge Question 13

Given that there are multiple technologies, including plunger lifts, downhole pumps and velocity tubing that are more effective at removing liquids from the well tubing than blowdowns, why do owners and operators of wells choose to perform blowdowns instead of employing one of these technologies? Are there technical reasons other than cost that preclude the use of these technologies at certain wells?

The disparity between reports into the GHGRP, discussed above, indicate that how a company or operation handles liquid unloading and specifically the philosophy regarding management of

reservoir energy with respect to well-bore liquid management has a very large effect on use of venting as part of well-bore liquid management.

Some operators choose to put production packers above the productive formation. These packers limit deliquification options to vent cycles or velocity strings since they preclude plungers, mechanical pumping, or the use of soap/surfactants.

At this time, deliquification of horizontal wells is a work in progress with considerable research ongoing to develop or improve technologies. When the flow rates decline to the point that there is inadequate velocity in the wellbore tubulars to allow the gas to lift the liquid there are examples of horizontal wells being placed on vent cycles simply because there is not an option.

Charge Question 14

Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from liquids unloading events and available options for increased product recovery and emissions reductions? The EPA is aware of an additional stage of the Allen et al. study to be completed in partnership with the EDF and other partners that will directly meter the emissions from liquids unloading events. However, the EPA is not aware of any other ongoing or planned studies addressing this source of emissions.

Other than the Phase 2 UT/EDF study mentioned, no studies of liquids unloading are known to be currently underway. However, data reported into the GHGRP in March of 2015 for the 2014 emission year will include additional information related to venting (previously deferred) that will provide significantly better understanding of venting for liquid unloading. Pending changes to Subpart W of the GHGRP will require reporting of additional data parameters in 2016 for the 2015 emission year, which will also aid in understanding of venting for liquid unloading.

C. Conclusion

As the GHGRP and API/ANGA data illustrate, venting for liquids unloading is a problem mostly driven by a relatively small number of operators and a relatively small subset of wells. This strongly suggests that a targeted intervention is appropriate to address this issue.

Since the frequent use of venting is restricted to a small number of operators and the GHGRP data makes this information public, operators that represent the majority of venting events are actively working to reduce/eliminate venting in their operations to avoid the public exposure in future reports. This alone is likely to significantly reduce the frequency of venting to aid liquids unloading and hence emissions. The assertion in the White Paper that installation of plunger lift systems is an emission (venting) control technique is not correct, not supported by the emission data, and not underpinned by a logical or technical analysis in the White Paper. It is absolutely true that plunger lifts are a valuable, effective and commonly used methodology/tool to assist in managing well-bore liquid loading. Plunger lifts do increase the efficiency of liquids removal from wells by the reservoir energy and hence do help maintain or increase production.

However, the efficacy of plunger lifts in reducing venting of wells and emissions is completely dependent on how they are operated. As the API/ANGA survey report, the GHGRP data, the U.S. Emission Inventory, and the ICF/EDF report shows: venting wells with plungers have higher emissions per well than venting wells without plunger lifts. From an emission perspective, wells with plunger lift systems accounted for about 72% of the GHGRP reported emissions from well venting for liquids unloading. **The general efficacy of plunger lift systems as an emission control measure is clearly not supported by the data.** However, with advanced well liquids unloading management (i.e. management of reservoir energy), large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made.

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Liquids Unloading

Well-bore Deliquification (Liquids Unloading) Background

Well-venting to unload liquids can be a significant source of hydrocarbon pollutant emissions and there are technologies and techniques in use and available to significantly reduce, but not eliminate, venting of wells to assist in deliquification. Deliquification of gas wells is a highly complex and technical subject with many approaches and technologies in use and venting of wells is one technique, often used in combination with other techniques that depend on reservoir pressure - such as plunger lifts, used to assist unloading. Well deliquification is a fundamental challenge for continued production from the majority of US gas wells and the proportion is expected to grow with new growth concentrated in non-traditional gas reservoirs such as shales, coal-beds, and tight-gas sands which are susceptible to liquid loading. Managing wellbore liquids loading is a primary focus for production engineers and operations teams. A very large amount of industry focus, research, and attention is applied to gas-well deliquification with innovation and research continually underway. For example, the 12th Annual Gas Well Deliquification Workshop was held in February 2014 in Denver, Colorado was attended by over 500 representatives of dozens of upstream producers. This workshop series, along with a portfolio of other venues dedicated to well deliquification and artificial lift, is organized by the Artificial Lift Research and Development Council (ALRDC), and the Southwestern Petroleum Short Course (SWPSC). This research and work is both optimizing and improving existing techniques along with developing entirely new types of systems. The flexibility to pilot some of these ideas/developments must be preserved – even if they ultimately do not succeed.

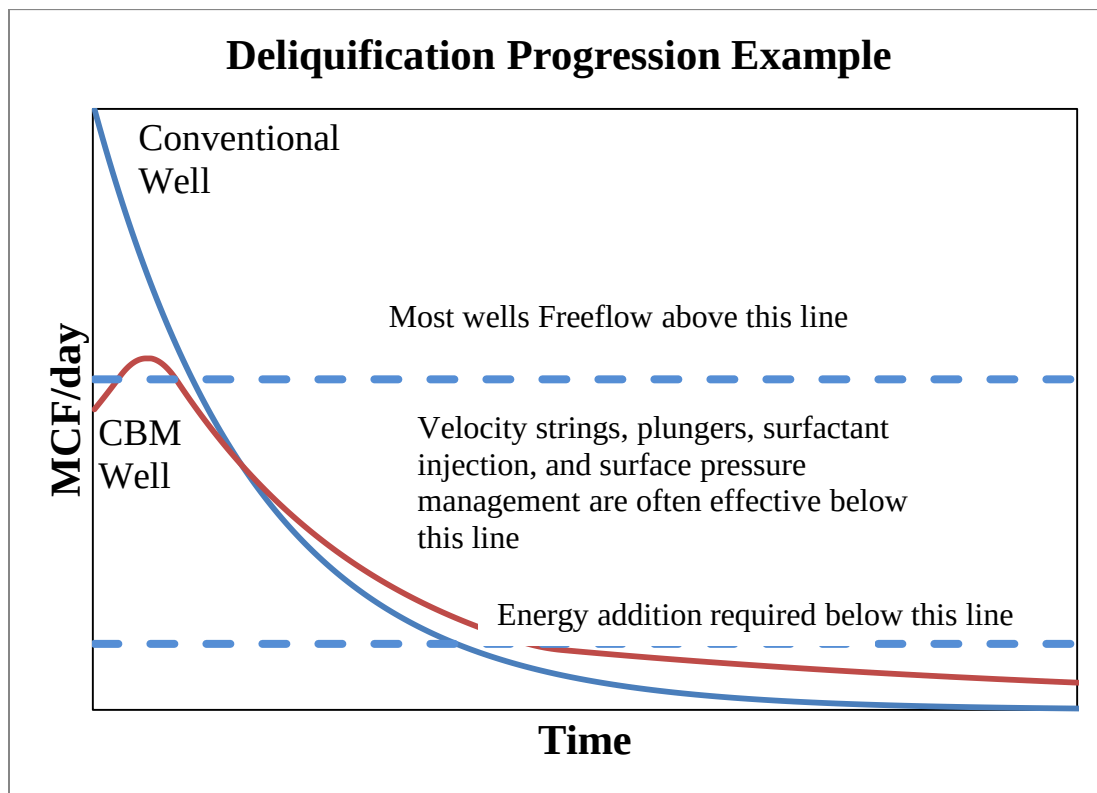
Liquid loading of well-bores occurs when the gas production-rate (velocity) up the well-bore is not sufficient to carry liquids up the well-bore. When a vertical liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and the production rate declines to the point where the well can quit flowing. According to the Energy Information Administration's 2009 "Distribution of Wells by Production Rate Bracket" some 338,056 (73%) wells out of a total gas well inventory of 461,388 gas wells produce 90 mcf of gas (15 BOE) or less per day (http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html) . These low rate wells are either impaired by liquids accumulation or are using some deliquification method to produce.

Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore. In the early stage of a well's life many (but by no means all)

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wells can flow freely and with sufficient velocity to avoid liquid loading problems. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquid-loading begins to be a problem and one of a portfolio of technologies or techniques will be used to help lift liquids using the reservoir's energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoir's energy is not sufficient to lift liquids and artificial lift energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The following figure shows a generalized well life-cycle curve with these different stages of a wells life illustrated.



To combat this normal well/reservoir depletion and assist liquid lift a number of techniques are used – dependent on the well configuration, reservoir properties, well depth, and surface equipment and collection system.

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Techniques that rely on the reservoir energy are:

- The tubing in a well may be changed to smaller diameter “velocity strings” which provide for higher velocity at any given flow rate and provide higher liquid lift capabilities. There is a decreasing benefit from smaller diameter velocity strings due to flowing friction buildup in smaller diameter tubing.
- Soap injection may be used to “foam” the liquids to reduce the unit density and enable liquids lifting.
- Wells may be put on a shut-in cycle to allow pressure/energy build-up of the reservoir near the well bore which equals higher production rates/velocity (temporary) and better liquids lifting.
- A plunger lift may be installed in a well. This is generally coupled with a shut-in cycle to build enough pressure under the plunger to lift it along with the liquid column.
- Venting a well may be used in conjunction with any of these techniques to create additional differential pressure/energy and aid unloading of liquids.

Techniques where energy is added to the well:

- Mechanical pumps are selected when rate of liquid accumulation is too high for plungers to operate or reservoir pressure is too low for plungers to operate without excessive shut-in time to build up reservoir pressure.
- Gas lift which raises tubing velocity to lift liquids by injecting gas down the tubing-casing annulus.
- Compression which lowers the surface pressure creating more differential for flow and increasing velocity by lowering pressure.
- Combinations of above approaches such as foaming, gas lift, and compression

The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of the production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology-selection requires a thorough understanding of the conditions that a reservoir is flowing into, the reservoir’s sensitivity to backpressure and the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology. Operators must have the flexibility to choose the most appropriate and cost effective approach for each individual well/reservoir/age/production combination and the regulatory certainty to underpin continued investment.

An excellent overview of this subject is Gas Well Deliquification, Second Edition, by Dr. James F. Lea, Dr. Henry V. Nickens, and Mr. Mike R. Wells (Gulf Publishing, 2008, ISBN 978-0-7506.8280-0). This 588 page book does a good job of explaining the basis for choosing among the various technologies, but it does not presume a one-size-fits-all solution.

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Well Venting to Aid Liquids Unloading

The production rate of a well, consequent velocity up the well-bore, and, hence, the ability to lift liquids is mostly a function of the differential pressure between the reservoir and the flow-line/collection system and the reservoir's sensitivity to backpressure. In order to flow, the total reservoir pressure must be greater than the total resistance to flow. This resistance is comprised of fluid friction and fluid interference across the reservoir; the flowing friction up the well-bore; the weight of the vertical fluid column in the well-bore; surface equipment and piping pressure losses; and the collection system/flow-line back-pressure. Opening a well-bore to atmospheric pressure (venting a well) removes the effect of the surface equipment/piping pressure-loss and the back pressure from the collection line and increases differential pressure to increase flow rates and velocities, which may enable the well to lift the liquid from the well-bore (unload the well). Venting of wells has been a common practice in low rate gas well deliquification for decades and is not restricted to wells without deliquification assist technologies, such as plunger lifts, in place. As the API/ANGA report and the GHGRP data show, venting of wells to aid liquids unloading occurs in both plunger equipped wells and non-plunger equipped wells with plunger equipped wells having higher reported emissions overall.

Minimizing Venting to Assist Liquids Unloading

As discussed above, there are various reservoir-driven techniques operators use in wells experiencing liquids loading to assist in deliquification, which also helps reduce the need for venting. Each of these may be the best solution for a particular portion of the life of a reservoir.

It is a misconception that plunger-lift systems are the single emission control action for wells where venting for liquids unloading occurs. This misconception is further exacerbated by a lack of understanding, even among those purporting plunger lift systems as *the* solution to liquids unloading, of liquids loading or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well-bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids hence making better use of the gas energy, and helps prevent liquids from falling back into the well-bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful. Plunger capacity is limited by well depth, differential between reservoir pressure/surface pressure, and the gas/liquid ratio that the well produces. Even plunger lifted wells reach a point where they lack the reservoir pressure to run a plunger against backpressure with adequate frequency to lift the liquid present. At that point the operator has the choice of replacing the plunger with a lift method that adds energy to the system or

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plugging the well. Operators analyze these wells and have to make the decision to spend capital and operating expense on a pump versus drilling a new well.

It also appears that EPA holds some misunderstanding of plunger lift. Although plungers are among the most common tools used in middle stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. While this can be controlled and minimized, it cannot be eliminated.

- One primary study/project that is often highlighted from the Natural Gas Star program is the BP “smart automation” well bore venting control system in the San Juan basin. What is generally misunderstood (or simply not acknowledged) is that about half of the wells which were venting (around 4.2 BCF of gas per year) were plunger equipped and were vented in order to generate the energy necessary to lift the plunger and liquid column. The fundamental nature of this project has also been mischaracterized as a project to install plunger lift systems to mitigate venting. The *actual* nature and success of the project was to optimize the shut-in times on individual wells and plunger cycle timing on wells with plungers through the use of automation that learned the performance of each well and then optimized the cycle parameters for that well – i.e. “smart automation”. This was and is a project about managing reservoir energy not about installing or running plunger lift systems. The basic concept is: “The reservoir does not quit working when a well is shut-in”.
 - The fact that it took about 6 years to fully develop the system and achieve 90% + venting reduction is also often ignored. It is technically and operationally very difficult.
- Plungers are not universally applicable to well-bores. For example, unless remedial action is taken, a plunger can’t be used in a well-bore with changing tubing sizes, defects or buildups of scale or in coil tubing which has an “internal upset” weld seam. Plungers can only be run where the inside of the well-bore is reasonably smooth and in reasonably good condition. They also do not work well in highly deviated directional (S-shaped – typical for multi-well pads) or horizontal well-bores.
- Although casing plungers are available for wells without tubing, they have had significant reliability problems and it is also difficult to control the velocity up the well-bore to avoid high velocities which have blown the top off of well-heads resulting in uncontrolled release of significant quantities of gas.
- Once a well/reservoir declines sufficiently, plungers will no longer work and energy must be added to the well-bore or the well abandoned. This is an economics decision.

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Studies and Data Sources

- API believes the only recent data/studies with a broad data set are the API/ANGA survey results and report and the GHGRP reported data.
- Care needs to be taken in use of the GHGRP data. For example, one company in one basin (one reporter/facility combination) accounts for about 37% of the industry wide methane emissions from liquids unloading. Any broad national “emission factor” should either exclude this data set or weight it according to the number of wells producing and/or venting.
- The UT/EDF study measured emissions from about 9 liquid unloading events but all were shale wells and hence do not represent the cross section of well/reservoir types. In addition, the supplemental information indicated that the researchers “triggered” an unloading event in some instances to enable measurement. If correct, the flow profile would not be equivalent to a well with a liquids column in the well-bore which inhibited flow and triggered venting to the atmosphere.
- Phase 2 of the UT/EDF study is purported to include measurement of a larger number of liquid unloading events from a cross section of well/reservoir types. The phase 2 report is expected to be published later in 2014.
- The annual U.S. Inventory of Greenhouse Gas Sources and Sinks estimate of emissions from liquids unloading also needs to be used with an abundance of caution. The radical variation in the estimated methane from liquids unloading; from 185.57 Gg in 2008 up to 4,554.42 Gg in 2009 (~2,354% increase) and then down to 249 Gg in 2011 (98% decrease) amply illustrates the uncertainty of the Inventory as a data source.
- The Natural Gas Star presentations and documents need to be fully understood, including the limitations of conditions, physical and operational, to their applicability – many/most are not universally applicable and this is often ignored. Also, many of the Natural Gas Star partner reported opportunities have been characterized incorrectly in some of the documentation – such as the BP project discussed above.

Options for Mitigating Venting for Liquids Unloading

Options dependent on reservoir energy

- Automated control of shut-in cycles and plunger runs (where equipped) to optimize building of formation/reservoir energy – used with both plunger and non-plunger wells. This will only work where a radial pressure gradient from low to higher exists in the reservoir as distance from the wellbore increases – which is typical for tight sands, shales, and some other formation types. The automation algorithms must be customized for each area

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(reservoir and well combinations) although the basis code, physics and approach are the same.

- A combination of flow measurement on the tubing and valve control on the tubing/casing annulus to allow the use of the tubing flow to manage liquid production while allowing well capacity in excess of the amount required for unloading to be produced up the tubing/casing annulus.
- Install plunger lifts along with appropriate control system. Plungers depend on formation/reservoir energy to lift liquids and cannot operate when energy declines beyond that necessary to lift liquids. Using automated control of shut-in cycles (above) will extend the period where plunger lift systems are effective without regular venting to assist plunger recovery.
 - Even with advanced plunger lift systems and control systems there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading (height of water column) in the well bore which can be caused by natural variation in reservoir flow, or system failures/malfunctions.
- Velocity (smaller diameter) tubing strings to increase velocity and liquid lift. However, there is a trade-off between tubing diameter and flowing friction back-pressure. As tubing diameter decreases, flowing friction increases which decreases differential pressure and hence flow rate/velocity. At small tubing diameters, the flowing friction decreases velocity more than the restricted flow area increases velocity. Velocity strings depend on formation/reservoir pressure to lift liquids.
- Soap/surfactant sticks or injection. These work by increasing the surface area/weight ratio of water hence increasing the ability of a certain velocity to lift liquids. Soap sticks and soap/surfactant injection are generally considered a stop-gap solution to liquids loading because balancing the amount of soap, the ability to activate the soap load, and the ability to deal with the formation damage that soap can cause generally shortens the effective period that this technique is adequate. Wells producing a high proportion of condensate or oil do not foam adequately and there is a potential to form emulsions which may prevent flow or need additional surface treatment. When using batch/soap sticks, the well will be shut-in to enable pressure build-up and chemical mixing. Then the well may be blown down to start flow again. This may reduce the overall blow-downs but will not eliminate them. Continuous injection needs to get the amount of chemical just right; too much = less production and foam on surface; too little = less production. A limitation of any surfactant is the chemical make-up of the liquid that must be lifted. Some wells load with water, others may load with condensed hydrocarbon liquids (condensate). The surfactant must be compatible with the liquids in the well, and condensate is more difficult to treat. As

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mentioned with other techniques, there is no “one size fits all” solution. Different foaming agents can have different effectiveness and the efficacy for an individual well will vary.

Options that add energy

- The economic life of a gas well is often defined by the ability to economically support installing deliquification methods. If a well cannot economically support the cost to add energy to a well for lifting liquids, it will be plugged and abandoned.
- Install additional surface compression to lower back-pressure against the well.
- Typical approaches to mechanical deliquification are a submersible pump, a beam pump (nodding donkey), and gas lift.
 - Submersible pumps are better suited to oil wells with high liquid volumes and they struggle with the low amount of liquids in a depleted gas well. If sufficient liquids are not produced and a “pump-off” controller does not work (common), they will burn out. Submersible pumps require a fairly high-voltage (440 V) electricity source at each well which is not common. Electrical cable must be run to the bottom-hole pump location to power the pump.
 - Beam pumps require a surface power unit and continuous rods from the surface to the bottom-hole plunger pump. While more forgiving of low liquid production volumes than submersible pumps, beam pumps are not very optimum for deviated well-bores such as those on multi-well pads (done to reduce surface disturbance). In a deviated well-bore, the rods will tend to rub against the tubing/casing and cause wear and failure of either the rods and/or the tubing/casing. Unless electricity is available, the surface power unit must be a gas fired reciprocating engine which adds significant emissions, complexity, reliability concerns, and operating costs.
 - Gas lift requires a higher pressure gas supply to “inject” down the casing-to-tubing annulus in order to increase the flow up the tubing thereby increasing the velocity and capacity to lift liquids. Gas lift typically requires additional compression and piping at the surface which requires either electricity to drive compressors or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.
 - For further information regarding gas well liquids loading, gas well liquids unloading, and artificial lift please see the Artificial Lift R&D Council web-site at <http://www.alrdc.com/production/>

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EPA Questions and Responses

EPA Questions: What is the feasibility of the use of flares during liquids unloading operations? Are there operational or technical situations where flares could not be used?

API is not aware of any instances where flares or other combustion devices are used during liquids unloading operations. In 2012, 58,663 discrete wells were reported into the GHGRP as vented for liquids unloading. Grossing this up, using EPA's estimate of 85% coverage under Subpart W, yields just over 69,000 individual wells vented to unload liquids in 2012. Flaring of gas during liquids unloading would necessitate separation of the liquids from the well stream in a separator or flare knock-out drum. Backpressure sufficient to unload liquids from the separator to a storage tank would need to be held against the well/separator which would directly reduce the differential pressure gained by routing to atmosphere and perhaps inhibit unloading. Due to the potential flow rate and Btu demand, flares would need to be dedicated to liquids unloading and be moderate size (~20 MMBtu/hr) rated. Liquids unloading flares would need either continuous pilots (for infrequent use) or electronic igniters powered by solar in most instances. Also, well-sites would need to be "re-piped" to route from the separator to the dedicated well unloading flare. Besides the technical difficulties dealing with the intermittent and surging flow characteristic of venting for liquids unloading, the changing velocities during an unloading and the problems of ensuring ignition for a sporadically used flare, the cost would be prohibitive. Multiplying the estimated total installed cost of \$100k per flare times the number of wells vented for liquid unloading in 2012, the cost would easily be *billions* of dollars. There are much more cost effective methodologies to reduce liquids unloading without the emissions and visual impact associated with flaring.

EPA Question: What is the feasibility of the use of artificial lift systems during liquids unloading operations?

This question indicates a somewhat fundamental misunderstanding of well liquids management. Artificial Lift, generally considered to be downhole pumps or gas-lift, eliminates the need to unload liquids due to the energy added directly to the well-bore. A pump or gas-lift is installed on a well when it can no longer unload liquids using the reservoir's pressure – but only if the expected production can support the additional capital and operating expense. Requiring early application of "artificial lift" would shorten the economic life of many marginal wells. This would tend to differentially impact small operators due to their tendency to hold portfolios of marginal wells.

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EPA Question: When is it infeasible to use a plunger lift system?

Wells with sufficient flow and velocity do not have liquids loading problems and there is no reason to even consider using a plunger lift system. Installing a plunger lift system in a well that does not have liquid loading problems is a waste of money. When a well does encounter liquids loading problems and a plunger lift is judged to be the best option, there are some limitations on when plunger lifts can be run in a well. Plunger lifts cannot be run in wells with variable tubing sizes, defects or scale build-up in the tubing, or in wells with coil-tubing that has an internally-upset weld seam. They can only be run in wells with reasonably smooth tubing. Plungers do not work well in highly deviated directional (S-shaped – typical for multi-well pads) wells. In a horizontal well, plungers will only run in the vertical portion of the well-bore. For wells without tubing, casing plungers are available but have had significant reliability problems and have experienced difficulties controlling the velocity up the well-bore to avoid high velocities which have blown the top off of well-heads resulting in the uncontrolled release of significant quantities of gas. Once a well/reservoir declines sufficiently, plungers will no longer work and energy must be added to the well-bore or the well abandoned. Again, this is an economics decision.

EPA Questions: Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where venting is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

Wells with plunger lift systems comprised ~55% of the more than 58,000 wells reported as venting for liquids unloading into the GHGRP for 2012. From an emission perspective, wells with plunger lift systems accounted for about 72% of the emissions from well venting for liquids unloading. The GHGRP reported data is broadly equivalent to that reported from the API/ANGA survey. With the API/ANGA survey outcome of about 36% of the well population being equipped with plunger lift systems yet responsible for over 50% of the venting wells and 70% of the emissions, **the efficacy of plunger lift systems as an emission control measure is clearly not supported by the data.** Although, with advanced well liquids unloading management, large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made. However, the need to vent will still occur. Even with advanced plunger lift systems and advanced control systems for both plunger lift and non-plunger lift equipped wells, there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading

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(height of water column) in the well bore which can be caused by natural variation in reservoir flow or system failures/malfunctions.

EPA Question: It is EPA's understanding that liquids loading becomes more likely as wells age due to declining well pressure.

See well lifecycle discussion in the background section above.

EPA Question: Is liquids loading only a problem for older wells or can wells develop liquids loading problems relatively quickly in certain situations?

Liquid loading is a function of the gas flow-rate from a well and the amount of water/liquid it produces which is somewhat independent of age. Older wells do tend to be lower producers due to being located in fields/reservoirs that have been produced for a long period and are partially depleted. However, not all old wells have liquid loading problems and not all new wells are immune from liquid loading problems.

EPA Question: Are certain wells more prone to developing liquids loading problems such as hydraulically fractured wells versus conventional wells?

The tendency of a well to have liquid loading problems is caused by a combination of lower gas flow rate and liquids production. Whether a well has been hydraulically fractured or not is immaterial. Because hydraulic fracturing tends to increase production, hydraulic fractured wells should tend to have fewer liquids loading problems than an equivalent non-fractured well. Due to their production profile, some coal bed wells tend to have liquids loading problems early in their life.

ICF/EDF Mitigation Paper Commentary – Liquids Loading

The ICF paper recommends plunger lift systems as the sole technology to reduce venting for liquids unloading and the consequent emissions. Although other techniques of managing well-bore liquids were briefly discussed, only installation of plunger lift systems was analyzed. Throughout the paper, the authors make a series of unsupported assertions and assumptions to arrive at their recommendation. Additionally, there are several instances where the authors' statements clearly indicate a limited understanding of liquids loading or the techniques used to manage liquids loading in wells. Some examples:

- *Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of venting (Figure 3 7).*

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- The assertion that plunger lift systems control and limit the amount of venting is not supported by the facts that plunger equipped wells account for the majority of both venting wells and emissions from venting for liquids unloading. Although a properly managed plunger lift system will help manage liquids unloading in a well, the impact on emissions will be dependent on the well and reservoir conditions along with how the plunger lift is setup based on these conditions.
- *If there is insufficient pressure to direct the gas to the sales line and the gas must be vented, the emissions can still be reduced by 90% compared to uncontrolled venting. ... Plunger lifts are a relatively low cost option and can be implemented in a relatively simple manual control method or more complex automated installations. ... Gas STAR Partners report reductions of venting emissions of 90% for plunger lifts that do not go to the sales line.*
 - The statement that simply installing a plunger lift in a well will reduce emissions by 90% appears to be anecdotal as the authors do not provide any source or reference for the information despite providing the source/reference for some of the other information in the report. The authors' implication that this level of emission reduction can be achieved absent appropriate management of the reservoir energy is simply unfounded.
- *While it seems counterintuitive that wells with plunger lifts that vent would be emitting more than those without plunger lifts, ICF interprets this information to indicate that most of the wells with the largest venting emissions have already installed plunger lifts while most of the remaining wells are venting infrequently or venting small volumes that do not justify the cost of installing plunger lifts.*
 - This "interpretation" by the authors is completely baseless and not correct. Plunger lift systems are installed in wells to assist with management of liquids loading and enable production - not to reduce emissions. The intent of plunger lift systems is to maintain production, not avoidance of emissions or recovery of emissions. This shows the authors' lack of understanding of liquids loading, management of liquids loading, and the industry's reasons for management of liquids loading.
- *Approaches to plunger lift operation range from ad hoc manual operation, to fixed mechanical timers, to programmable "fuzzy logic" automated controllers. Specific data on the potential reductions from optimized plunger lift operation is not available but it is clear from industry experience that an integrated program of training, technology, and automation can improve the performance of plunger lifts for both productivity and emission reductions.*
 - This statement by the authors ignores the BP "smart automation" project, discussed above, which is focused on the impact (>90% reduction) that optimized management of formation energy on a well-by-well basis can have on emissions,

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presented at Natural Gas Star conferences numerous times, and well known to at least one of the ICF authors. At worst, this indicates the authors bias to select information and make assertions that supports a desired outcome and not include information and data that conflicts with their pre-determined goal. At best, it indicates a very cavalier approach to the complex subject of liquids loading which is central to keeping many of the US gas wells producing and which is the focus of ongoing and substantial industry effort and research.

It is not clear what population of venting wells ICF used in their analysis of the economics of installing plunger lift systems. In the body of the report, the authors note about 127,000 wells vented for liquids unloading reported into the GHGRP for 2012. In appendix B, the authors note 69,054 wells reported into the GHGRP as the average for 2011 and 2012. The latter number agrees with API's analysis of the GHGRP data for liquids unloading which shows 69,525 and 58,633 wells vented for liquids unloading in 2011 and 2012, respectively.

Overall, the ICF/EDF report recommendation of a single technology, plunger lift systems, as a solution to reducing liquids unloading emissions widely misses the mark. While significant reductions in emissions from venting wells for unloading liquids, in both plunger equipped and non-plunger equipped wells, are possible using cost-effective techniques, recommending a *single* approach is not appropriate. An integrated approach, choosing between all of the tools available, in a manner appropriate for the well and reservoir – after engineering analysis, and including management of reservoir energy will be necessary to achieve significant reductions.

Recommended Charge Questions for Peer Reviewers

1. Do the data sources and studies that the paper relies upon appear credible and complete?
2. Was sufficient QA/QC conducted with regard to the data sources and studies that the paper relies on to determine their applicability and validity?
3. Are the conclusions reached by the authors supported by the information and data that was relied upon?
4. Are assertions made in the paper supported by the underlying facts and data?
5. Are assumptions made in the paper clearly noted? Do these assumptions seem valid and balanced?
6. Does the paper reflect an understanding of the complexity of liquids loading in gas wells and the technologies and techniques used by industry at appropriate points in a well's life-cycle to manage liquids loading?
7. Does the paper reflect an understanding of the fundamental nature of liquid loading management to the continued ability to produce the majority of the onshore US gas wells?

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8. Does the paper adequately discuss the constraints for use of plunger lift systems and the fact that venting of wells equipped with plunger lift systems accounts for greater emissions in the GHGRP data and the API/ANGA report?
9. Does the paper present a realistic evaluation of actual emission reduction potential from regulation of venting for liquids unloading?

Attachment E

Comments on the Benefit-Cost Analysis
in EPA's Regulatory Impact Analysis

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1.0 INTRODUCTION

The EPA has prepared a Regulatory Impact Analysis (RIA) of the proposed New Source Performance Standard (NSPS) Subpart OOOOa rules for reducing methane emissions at newly constructed, reconstructed, and modified oil and gas facilities. RIAs are required for rules that will have an annual effect on the economy in excess of \$100 million. Based on Executive Orders 12866 and 13563, the EPA is required to use the best available scientific and economic information to quantify the benefits and costs of proposed rules. According to the EPA, the rigorous evaluation of benefits and costs has been a key component of its rulemaking process for decades.

The monetary benefits of the proposed rule are estimated using an estimate of the social cost of methane (SC-CH₄), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). The EPA believes that the rules may also improve air quality and reduce health expenditures from exposure to hazardous air pollutants (HAPs), ozone, and particulate matter (PM); however, the EPA states that there are too many difficulties in modeling these benefits and chooses to measure potential benefits only from climate change via the SC-CH₄.

Annualized engineering costs are estimated for each source based on capital costs, one-time labor costs, and on-going annual costs. EPA projects both the total costs and total benefits for the first year the full rule is in effect (2020) and for 2025. The net benefits in these years are the difference between the total benefits and costs, measured in 2012 dollars.

For the EPA's preferred option (Option 2), the RIA estimates that the annual compliance costs of the proposed rule will range from \$320 to \$420 million by 2025, measured in 2012 dollars. It also concludes the annual benefits will be between \$460 and \$550 million (using a three percent discount rate). Based on these estimates, EPA concludes that the proposed rule has positive net benefits (i.e., benefits greater than costs); however we note that the difference is marginal.

ERM reviewed the assumptions, calculations and analysis used in the RIA to develop the cost and benefit estimates on behalf of API. This review shows that there are significant problems with the cost and benefit estimates contained in the RIA and with the treatment of uncertainty. Specifically, our review finds that:

- The RIA omits key cost categories and relies on inaccurate cost and emission information, which results in an underestimate of total costs and an overestimate of the emission reductions.

- The RIA does not provide adequate breakdowns of benefits and costs by source, which obscures important information about the cost effectiveness of the rule.
- The SC-CH₄ has inherited all of the problems that plague the social cost of carbon estimates, and the EPA's own peer-review of the SC-CH₄ does not demonstrate that it is economically and scientifically defensible.
- The uncertainty surrounding the benefits and costs is not adequately reflected in the RIA, which does not comply with EPA guidelines for conducting benefit-cost analysis.
- The RIA does not report the net benefits to the United States as required by Office of Management of the Budget (OMB) , only global net benefits.

Overall, ERM concludes that the proposed rule has costs that are significantly greater than the benefits after the corrections are made. Specifically:

1. After correcting for problems with the EPA cost estimates and emission reductions, the point estimate for total costs is \$831 million and annual net benefits is -\$452 million in 2025 (i.e., costs significantly greater than benefits).
2. The most significant source affected by the revisions is fugitive emissions from well sites, where the net benefits are -\$405 million in 2025.
3. After formally accounting for the uncertainty, we estimate global net benefits will range from -\$0.92 and \$0.17 billion. There is nearly a 90 percent probability that the actual net benefits will be less than the EPA net benefit estimates. There is an 82 probability that net benefits will be negative.
4. Expected annual net benefits for the U.S. will range from will range from -\$1.07 billion to -\$0.56 billion in 2025.

The remainder of this introduction (Section 1) provides an overview of these findings. Section 2 provides a detailed discussion of the cost analysis, Section 3 discusses the social cost of methane estimates, and Section 4 describes the impact of uncertainty on the analysis.

1.1 OVERVIEW OF ISSUES WITH EPA'S COST AND EMISSION REDUCTION ESTIMATES

Table 1-1 summarizes the source-specific estimates for the 2025 benefits and costs using EPA numbers compared with revised and corrected estimates developed by ERM. While EPA does not provide a breakdown of the benefit-cost analysis in the RIA by regulated source and industry sector, ERM re-created the source-specific estimates based on the input data provided in Tables 3-16 and 4-3 of the RIA, and supporting technical documentation provided by EPA. Evaluating the source-specific estimates is critical to evaluating overall value of the rule. For example, Resources for the future

(RFF) recently conducted a retrospective analysis of RIAs and found that analyses based on average costs and/or benefits will often obscure important differences in impacts across the groups affected by the regulation. (Morgenstern 2015).¹ The heterogeneity of net benefits across sources is clearly evident in this RIA and affects the cost-effectiveness of the rule.

For completeness, Table 1-1 shows all of the sources and sectors included in the RIA. However, this review focuses only on well completions, fugitive emissions from oil and gas wells and pneumatic pumps at well sites. Combined, these sources and sectors account for approximately 80 percent of EPA's estimated methane gas emission reductions and over 90 percent of EPA's estimated costs.

The first set of columns in Table 1-1 show the benefits, costs and net benefits based on EPA assumptions and calculations. Within the RIA, the EPA does not provide annualized benefits for reducing emissions from fugitives at both oil and gas well sites separately; it reports only a single annual value for fugitive emissions from well sites. In 2025, the RIA estimates annual costs for well site fugitive controls will be \$160 million and that annual benefits will be \$150 million (using a 3 percent discount rate). Thus, as a group, fugitive emission controls for well sites do not pass the benefit cost test, with net benefits of negative \$10 million, even when using the EPA benefit and cost numbers.

The second set of columns in Table 1-1 correct a number of other issues that were identified with EPA's benefit cost analysis. These include:

1. Oil well completions: EPA underestimated the cost of combustion controls for oil well completions. An adjustment was also made to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline scenario. Adjusting the estimated costs and the emission reduction estimates to reflect the fact that many hydraulically fractured development oil well completions are already being controlled in the baseline results in costs that are higher than benefits.
2. Fugitives from well pads: EPA overestimated the emission reductions for fugitive emissions in their analysis. The model plant baseline emissions for both oil and gas well sites were estimated by rounding up the counts of major equipment at a well site and then multiplying by the component counts per major equipment. The resulting estimate was an overstatement of baseline emissions and corresponding emission reductions of 30-35 percent.

¹ Morgenstern, Richard. 2015. The RFF Regulatory Performance Initiative: What Have We Learned? RFF Discussion Paper. RFF DP 15-47.

EPA also excluded many cost elements in their estimates for semi-annual OGI leak screening and repair for well sites. Table 1-1 shows the impact of correcting these major flaws in the EPA cost estimates and correcting the estimated component counts for the model plants. These adjustments show that both oil and gas well sites fail the benefit-cost test. Correcting the issues identified changes the outcome of the benefit-cost analysis for fugitive emissions alone.

3. Pneumatic Pumps: Several corrections were made to the estimates for pneumatic pumps that significantly change the net benefits estimate. These corrections include: a) adjusting the annual operating time for diaphragm pumps to 4 months of the year, on average; and b) correcting the costs of routing the pump vent to an existing control device, consistent with the estimate EPA used for wet seal compressor vents.

The ERM estimates address various deficiencies in the RIA cost estimates. In Sections 3 and 4 we describe the numerous problems with the EPA's SC-CH₄. Putting aside those problems for a moment, even using the EPA's SC-CH₄ estimates, our analysis shows that overall net benefits are negative. The total benefits in 2025 are around \$400 million (vs. EPA's \$460 million) and the costs are over \$810 million (vs. EPA's \$310 million) for EPA's preferred regulatory approach (Option 2). Therefore, the overall proposed regulatory program results in a net benefit of -\$410 million, and does not pass a benefit-cost test. In addition, virtually all of the source-specific net benefit estimates are also negative.

Table 1-1. Comparison of 2025 Annual Benefits and Costs – Option 2, Low Impact, Discount Rate 3%

SourceEmission Point		EPA Estimates				ERM Estimates			
		Reduced CH4 Emissions (Mt)	CH4 Benefits (\$M)	Annualized Cost (\$M)	Net Benefits (\$M)	Reduced CH4 Emissions (Mt)	CH4 Benefits (\$M)	Annualized Cost (\$M)	Net Benefits (\$M)
Well Completions	Hydraulic Fracturing – Development	117,934	\$177	\$120	\$57	122,908	\$184	\$208	(\$24)
	Hydraulic Fracturing – Exploration	9,979	\$15	\$4	\$11	10,284	\$15	\$12	\$4
Fugitive Emissions	Well Pads	99,790	\$150	\$160	(\$10)	68,838	\$103	\$508	(\$405)
	Oil Wells	33,980	\$51	\$119	(\$68)	21,685	\$33	\$338	(\$305)
	Natural Gas Wells	71,651	\$108	\$46	\$61	47,153	\$71	\$171	(\$100)
	Gathering & Boosting Stations	29,937	\$45	\$17	\$28	Not Evaluated (used EPA's estimate)			
	Transmission Compressor Stations	9,072	\$14	\$3	\$11	Not Evaluated (used EPA's estimate)			
Pneumatic Pumps	Well Pads	29,030	\$44	\$5	\$38	11,186	\$17	\$57	(\$40)
Pneumatic Controllers	Transmission & Storage Stations	7,983	\$12	\$0.8	\$11	Not Evaluated (used EPA's estimate)			
Reciprocating Compressors	Transmission & Storage Stations	608	\$0.9	\$0.7	\$0.2	Not Evaluated (used EPA's estimate)			
Centrifugal Compressors	Transmission & Storage Stations	3,175	\$5	\$0	\$5	Not Evaluated (used EPA's estimate)			
Total		307,508	\$460	\$310	\$150	263,992	\$396	\$806	(\$410)

1.2 OVERVIEW OF ISSUES ASSOCIATED WITH THE SOCIAL COST OF METHANE

There are numerous issues associated with the use of the SC-CH₄ estimate to quantify potential benefits of methane emission controls. The SC-CH₄ is derived using an approach that the EPA claims is “consistent with” the Interagency Working Group (IWG) approach for estimating the SCC. Therefore the SC-CH₄ inherits all of the weaknesses of the SCC and it is far from clear that either the SCC or SC-CH₄ provide the “scientifically and economically defensible” estimates that are required for conducting meaningful benefit–cost analysis. The EPA asked three peer-reviewers to evaluate the SC-CH₄ estimates and they identified serious concerns with estimates. (See Section 3.1)

The SC-CH₄ was derived based on modeling results from three Integrated Assessment Models (IAMs) that are the basis for the SCC estimates as well. The three IAMs predict different climate impacts from the same change in emissions. It is not clear whether this reflects true scientific uncertainty or inconsistencies in the modeling (EPRI 2014).² Even if the results do reflect scientific uncertainty, Gillingham et al. (2015)³ show relying on variation in model outcomes as a measure of uncertainty captures only a small fraction of the total variation in many important climate change outcomes. They also show that assumptions about the rate of technological change can have a profound effect on the estimates of SCC. Most importantly, the monetary damage functions that underlie these IAMs have no theoretical basis (Pindyck 2013).⁴

The range of discount rates used by the EPA reflects the rates typically used in U.S. policy analysis. However, if EPA wants to illustrate the potential global benefits, the illustration should include the discount rates used by other nations Florio and Sirtori (2013)⁵ report that discount rates used by governments throughout the world range from 3 to 15 percent. As Pindyck (2013) states, the choice of discount rates in climate change IAMs is arbitrary, yet it has huge effects on the estimated social cost of emissions generated.

² S.K. Rose, D. Turner, G. Blanford, J. Bistline, F. de la Chesnaye, and T. Wilson. Understanding the Social Cost of Carbon: A Technical Assessment. EPRI, Palo Alto, CA: 2014. Report #3002004657.

³ Gillingham et al. 2015. Modeling Uncertainty in Climate Change: A Multi-model Comparison. Cowles Foundation Working Paper. No. 2022.

⁴ Pindyck, Robert. 2013. “Climate Change Policy: What Do the Models Tell US”. Journal of Economic Literature 2013, 51(3): 860-872.

⁵ Florio and Sirtori. 2013. “The Social Cost of Capital: Recent Estimates for the EU Countries. Centre for Industrial Studies. Working Paper Series. http://www.csilmilano.com/docs/WP2013_03.pdf

1.3 OVERVIEW OF THE IMPACT OF UNCERTAINTY

The uncertainties surrounding the benefits and costs are not adequately reflected in the RIA. The EPA guidelines for benefit-cost analysis indicate that quantitative information should typically include both a best estimate, and a range or confidence interval. The RIA reports a range of benefits and costs, but only to reflect uncertainty of whether low producing oil and gas wells are subject to fugitive emissions controls. However, there is uncertainty about the costs (at a minimum, a range should have been generated to reflect standard engineering cost uncertainties) and the SC-CH₄. A recent RFF analysis of RIAs provides explicit support for evaluating the impact of uncertainty, because it can affect the RIA conclusions and may warrant the consideration of alternative regulatory designs (RFF 2015).

This review uses Monte Carlo analysis to provide a more complete picture of the impact of uncertainty. First, we provide a more robust characterization of the distribution of SC-CH₄. This is accomplished by using Monte Carlo data provided by Marten et al. (2014) that shows the full distribution of SC-CH₄ across IAMs, socio-economic scenarios, and discount rates (see Section 4.2 for details). Second, we construct ranges for the cost categories and emission reductions. Uncertainty about the costs is handled by estimating a range of potential costs for each of the major elements of the total costs. Depending on circumstances, the range can encompass both the EPA and ERM in Table 1-1 and/or standard engineering costing procedures.

Table 1-2 shows the results of a Monte Carlo analysis of the net benefits. Uncertainty about benefits is quantified by using data from Marten et al. (2014).

Table 1-2. Summary of the Annual Net Benefits Monte Carlo Results – 2025, EPA Option 2

Emission Source/Sector	Percentiles of Distribution \$MM			Probability Net Benefits are Positive	Probability Net Benefits Exceed EPA Estimate
	5 th	50 th	95 th		
Well Completions	-208	-58	266	22%	17%
Fugitive Emissions/Oil Well Pads	-547	-355	-192	0.2%	0.4%
Fugitive Emissions/ Natural Gas Well Pads	-222	-115	78	11%	6%
Pneumatic Pumps/Well Pads	-68	-38	4	6%	2%
Total of Above Categories	-1,044	-557	155	--	--

The results of the Monte Carlo simulation illustrate not only the high degree of uncertainty around EPA's point estimates, but also their improbability. Over all emissions sources/points ERM evaluated, the simulated distributions show that net

benefits range between -\$1.04 billion and \$0.16 billion 90 percent of the time—a range of more than \$1.0 billion in a single year. The extreme width of the distribution suggests there is not a meaningful way of concluding net benefits will be positive. Aside from well completions, there is less than a 10 percent chance that net benefits exceed EPA's estimate for the other emission sources/sectors ERM modeled. In the case of fugitive emissions controls at oil wells, the probability is less than 1 percent.

1.4 U.S. vs. GLOBAL IMPACTS

In the RIA analyses, EPA only reports the global benefits for SC-CH₄, despite the fact they are required to show the U.S. benefits. While exact numbers for the U.S. are not provided by EPA, the EPA previously estimated that between 7 percent and 23 percent of global SCC total benefits actually accrue to the U.S.⁶ Using this range we computed the U.S. net benefits by subtracting between 7 and 23 percent of total benefits from 100 percent of the costs in the Monte Carlo model. This results in a range of net benefits from -\$1.07 to -\$0.56 billion in 2025.

⁶ EPA 2015. Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

2.0 TECHNICAL ANALYSIS OF COST AND EMISSION REDUCTIONS

To understand the basis of the costs and emission reductions that EPA used in the benefit-cost analysis, a detailed review of the Technical Support Document (TSD) for the proposed NSPS Subpart OOOOa was conducted. This section summarizes the key findings from the TSD review and discusses the impacts on the benefit-cost analysis.

2.1 FUGITIVE CONTROLS

The following comments are based on ERM's review of the underlying basis and assumptions that EPA used in their analysis of net benefits for fugitive emissions. The proposed fugitive emission control scenario is semi-annual leak detection and repair (LDAR) using optical gas imaging (OGI) for well sites, gathering and boosting, and transmission and storage. The findings of the review indicate that EPA underestimated the costs of the proposed controls and overestimated the emission reductions.

2.1.1 Fugitive Control Costs

Underestimate of Leak Survey Cost

In the cost estimation for implementing the LDAR requirements under Subpart OOOOa, EPA underestimated the cost of conducting a leak survey at the model well sites. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site (\$600/single well battery⁷) as the basis of the leak survey costs. The actual cost of the survey, based on the reference document EPA used, would be higher than the value used in the analysis that represents a single well site (\$600/single well battery) and lower than the value provided for a multiple well site (\$1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range, an estimate of \$720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

⁷ Carbon Limits. "Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras". December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.

Omission of Additional Cost Elements for LDAR Program

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey. EPA's cost analysis failed to consider costs associated with training, monitoring device calibration and transportation. These are not insignificant and should be part of EPA's assessment of the costs of the proposed requirements. As indicated in the comments on fugitives, additional costs based on data from companies subject to Colorado Regulation 7 were included to evaluate the impacts to net benefits. Annualized costs associated with semi-annual OGI leak survey and repair based on the CO Regulation 7 estimates are \$6,353/yr/well site, compared with EPA's estimate of \$2,230/yr/well site. Table 2-1 compares the total annualized costs for fugitive emissions controls at well sites in 2025 using EPA's estimated control cost and ERM's corrected control cost incorporating industry information from CO Regulation 7. The estimated total annualized costs using ERM's corrected estimate is significantly higher—more than three times—than EPA's estimate reported in the RIA. ERM's cost estimate is documented in the fugitive controls comment section.

Table 2-1: Cost Comparison for Fugitive Emissions

Emission Point	EPA Estimates		ERM Estimates	
	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)
Well Pads	99,790	\$160	68,838	\$508
Oil Well Site	33,980	\$119	21,685	\$338
Gas Well Site	71,651	\$46	47,153	\$171

Omission of Costs for Well Sites in Regulated States

EPA excluded well sites in regulated states from the cost analysis, but did not exempt those sites in the proposed Subpart OOOOa rule. Specifically, EPA excluded well sites in regulated states in their baseline and projections of affected oil and gas well sites in 2020 and 2025. The exclusion of well sites in regulated states has the effect of reducing both costs and emission reductions, so no net effect on cost effectiveness. However, the rule as proposed does not exclude well sites in regulated states, which is not consistent with EPA's cost analysis. If well sites in regulated states are not exempt from Subpart OOOOa requirements, those affected well sites would incur higher costs to implement the additional LDAR requirements, with little to no net emissions reductions. The resulting costs would be higher than EPA estimated if those regulated well sites are not exempt from the rule.

2.1.2 Fugitive Emission Reduction Estimate

Overstatement of Methane Composition for Oil Well Sites

EPA assumed that the methane composition for fugitive leaks from oil well sites was equivalent to gas well sites at 82.9 percent methane by volume. In contrast, EPA assumed a methane composition of 46.7 percent by volume in their analysis of oil well completion emissions and costs. To be conservative, we used 82.9 for fugitive leaks from oil well sites instead of the more realistic 46.7 percent. If we had used the more realistic value, the overall benefit-cost analysis would be further negatively impacted.

Overestimate of Component Counts

EPA's approach for estimating component counts for the model plant gas and oil well sites overstates emissions and emission reductions. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. As shown in Table 2-2 below, the effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the emission reductions as follows:

- Gas well sites: Baseline emissions decrease from EPA's estimate of 4.54 tons CH₄/yr/well site to an unrounded estimate of 3.18 tons CH₄/yr/well site, or a 30 percent reduction in methane baseline emissions and corresponding emission reductions.
- Oil well sites: Baseline emissions decreased from EPA's estimate of 1.09 tons CH₄/yr/well site to an unrounded estimate of 0.70 tons CH₄/yr/well site, or a 36 percent reduction in methane baseline emissions and corresponding emission reductions from correcting the component counts.

Table 2-2. Comparison of EPA Rounded-Up vs. Unrounded Estimate of Baseline Emissions

Model Plant	EPA Baseline using Rounded-Up Data					Corrected Baseline using Unrounded Data				
	EPA Assumed Equipment Counts		EPA Assumed Component Counts		EPA Baseline, tons CH ₄ /yr/ well site	Corrected Equipment Counts		Actual Component Counts		Actual Baseline, tons CH ₄ /yr/ well site
Gas Well Sites	Wellheads	2	Valves	114	4.54	Wellheads	1.81	Valves	80	3.18
	Separators	2	Connectors	414		Separators	1.41	Connectors	293	
	In-line Heaters	1	OELs	14		In-line Heaters	0.74	OELs	10	
	Dehydrators	1	PRVs	6		Dehydrators	0.50	PRVs	4	
Oil Well Sites	Oil Wellheads	2	Valves	29	1.09	Oil Wellheads	1.81	Valves	18	0.70
	Separators	1	Connectors	104		Separators	0.72	Connectors	61	
	Headers	1	OELs	1		Headers	0.70	OELs	1	
	Heater/Treaters	1	PRVs	1		Heater/Treaters	0.06	PRVs	1	

Growth Rate Inconsistency

EPA used an inconsistent approach for projecting affected gas well sites for onshore production sector and the gathering and boosting sector. To estimate the number of affected gas well sites and gathering and boosting stations in 2020 and 2025, EPA used an estimated annual growth rate for gas wells. For gas well sites, EPA used a 6.45 percent annual growth rate based on the National Energy Modeling System (NEMS) model as the basis for projecting new gas well sites in the onshore production sector. In contrast, EPA used a 3 percent annual growth rate for new gas wells as the basis for projecting new gathering and boosting stations. If EPA used the same 3 percent growth rate for gas well site projections for the onshore production sector, the overall benefit-cost analysis would be further impacted, meaning the net benefits would be even lower. To be conservative, ERM used 3 percent.

Overestimate of Gathering and Boosting Station Component Counts

EPA's approach for estimating the model plant gathering and boosting station component counts overstates baseline emissions and emission reductions. EPA rounded up the average number of compressors per compressor station in estimating component counts for the model plant baseline emissions. Further, they also used an inconsistent approach for projecting the number of affected gathering and boosting stations in 2020 and 2025. The assumptions EPA used for estimating baseline emissions for the gathering and boosting station model plant and for projecting the number of affected new facilities include:

- 5.0 compressors per station used for model gathering and boosting station component counts. This is based on rounding up the estimated 4.5 compressors per gathering and boosting station;
- 4.5 compressors per station assumption used to project number of new facilities for 2020 and 2025.

The impact of rounding up the number of compressors per gathering and boosting station from 4.5 to 5.0 is a 10 percent overstatement of the component counts, which translates into 10 percent overstatement of baseline emissions and emission reductions. Note that this overstatement was conservatively not corrected in the revised benefit cost analysis figures.

2.2 PNEUMATIC PUMPS

EPA estimated emission reductions and costs of controls for the production sector. A review of the cost analysis for the proposed controls for pneumatic pumps indicates that EPA underestimated costs and likely overstated emission reductions.

2.2.1 Pneumatic Pump Control Costs

EPA estimated the cost of control, i.e., routing a pneumatic pump vent to an existing control device, as a one-time cost of \$2000. Using a 7 percent discount rate over 10 year estimated life of a pump, the annualized cost of control was estimated at \$285/year. EPA's reference for the cost estimated is from a NG STAR Fact Sheet⁸ for routing a glycol dehydrator circulation pump vent to an existing vapor recovery unit (VRU). The value assumed is an underestimate of the total cost that would be required for engineering design and piping installation for a vent system retrofit to route a very low flow, low pressure vent stream to an existing flare or VRU. This estimate is also inconsistent with the estimated cost of \$23,252 assumed for routing a wet seal compressor vent to an existing control device (Section 8.4.4.3 of TSD). ERM believes the value of \$23,252 is closer to the uninstalled capital cost that would be incurred. Utilizing EPA's assumed 7 percent interest rate, this equates to an annualized cost of \$3,308. Note that this estimate does not include the engineering and design analysis needed to ensure that the control device has adequate capacity and that the flow characteristics for a low flow, low pressure source can safely be routed into the existing flare or VRU header. The costs also do not include the recurring annual costs associated with monitoring and testing at sites not otherwise subject to Subpart OOOOa.

⁸ Natural Gas EPA Pollution Preventer. 2011. "PRO Fact Sheet No. 203: Pipe Glycol Dehydration to Vapor Recovery Unit". <http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf>

2.2.2 *Pneumatic Pump Emission Reduction Estimate*

EPA's estimates of baseline emissions and emission reductions are overstated, as indicated in the sections below.

Overestimate of Diaphragm Pump Baseline Emissions

EPA assumed that both diaphragm pumps and chemical injection pumps operate continuously, year round, i.e., 8,760 hours of operation per year. However, EPA acknowledges that diaphragm pumps are used for circulation of heat transfer fluids to prevent freezing, meaning that they are commonly only operated seasonally. A better estimate of the actual time in operation is 3 – 4 months per year. Using 4 months per year as an average time in service, the emission reductions for diaphragm pumps are one-third the value that EPA assumed in the cost analysis.

Overstatement of Methane Composition for Oil Well Sites

EPA assumed that the methane composition for the vent from all pneumatic pumps in production is consistent across all well sites at 82.9 percent methane by volume. Similar to the discussion above for methane composition for fugitives from oil well sites, a better estimate of methane composition is 69.5 percent by volume. This corrected estimate was assumed in the revised estimates of net benefits from pneumatic pump controls at production well pads.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

The projected number of new pneumatic pump sources in 2020 and 2025 was based on an estimated annual increase in the number of pumps using a 10 year average of pneumatic pump net increases from the Inventory of U.S. GHG Emissions and Sinks: 1990-2013.⁹ EPA only used the net increases from year to year (i.e., the positive net increase values), instead of the overall net change over the 10 year period. This approach would likely overstate the number of new pumps, because it is not reflective of a true change over the 10 year period.

Another source of uncertainty is EPA's estimate of the split between chemical injection and diaphragm pumps that EPA assumed in the projection of affected sources in 2020 and 2025. Specifically, EPA assumed that new and replaced pumps were evenly split 50/50 between diaphragm and piston pumps.¹⁰ This reference cited by EPA has no information on pump demographics in the O&G industry. Since the estimated baseline

⁹ U.S. EPA. 2015. "Inventory Of U.S. Greenhouse Gas Emissions and Sinks. 1990-2013."

<http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf>

¹⁰ GlobalSpec. Undated. "Diaphragm Pumps Information." Available at

http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps

emissions from piston pumps are a factor of 10 lower than diaphragm pumps, the baseline, emission reductions, and net benefits estimates are highly sensitive to this assumption. EPA used different assumptions of the pump type split between diaphragm and piston pumps for their analysis of an alternate control option (instrument air system), ranging from 25, 50, and 75 percent for each pump type.

Corrected Net Benefits Estimate for Pneumatic Pumps

ERM used the following corrections to estimate a revised net benefits estimate from pneumatic pumps at well sites:

- Annual cost of \$3,308/well site;
- Methane composition for pneumatic pumps at oil well sites of 69.5 percent by volume (compared to 82.7% by EPA); and
- Diaphragm pumps operational 4 months per year, on average.

The comparison of benefits and costs estimated by EPA and corrected to account for the issues identified above are shown below.

Table 2-3: Cost and Emissions Comparison for Pneumatic Pumps

Emission Point	EPA Estimates		ERM Estimates	
	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)
Well Pads	30,934	\$5.1	11,186	\$57

2.3 OIL WELL COMPLETIONS

EPA proposed the following controls for hydraulically fractured and refractured oil well completions:

- Subcategory 1 wells – non-wildcat, non-delineation wells: reduced emission completions (REC) and combustion device;
- Subcategory 2 wells – wildcat, delineation wells: combustion device.

Based on ERM's review, the control costs may be understated and the emission reductions overstated.

2.3.1 Oil Well Completion Control Costs

Underestimate of Oil Well Completion Combustion Device

The cost of a completion combustion device was estimated to be \$3,723 in 2012\$ based on the 2012 NSPS by EPA. Based on public comments to EPA from the Independent Producers Association of New Mexico (IPANM) on the Methane White Papers, members estimated the cost for flaring oil well completions at over \$10,000. This is believed to be a more reasonable cost to rent, transport, install, operate and remove separator and flare equipment.

2.3.2 Oil Well Completion Emission Reduction Estimate

Overestimate of Oil Well Completion Baseline Emissions and Emission Reductions

EPA's estimates of the baseline emissions and emission reductions from hydraulically fractured and refractured oil well controls are overstated. EPA incorrectly assumes that all hydraulically fractured oil well completions and recompletions are not controlled, except in Wyoming and Colorado. This assumption is not correct as many companies already use REC and/or combustion devices to control the flowback emissions from oil well completions. Therefore, EPA's baseline emissions are overstated and the resulting emission reductions achievable are also overstated.

Corrected Estimate for Oil Well Completions

ERM used the following corrections to estimate a revised net benefits estimate from oil well completions:

- Assumed 25 percent of developmental oil wells are already controlled. Note that the estimated controlled hydraulic fracturing at oil well sites is based on industry experience and is above and beyond the state control requirements.;
- Cost of combustion device for oil well completions estimated at \$10,000.

Table 2-4 compares the benefits and costs estimated by EPA and the corrected values.

Table 2-4: Cost and Emissions Comparison for Oil Well Completions

Emission Point	EPA Estimates		ERM's Estimates	
	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)	Reduced CH ₄ Emissions (Mt)	Annualized 2025 Cost (\$M)
Hydraulic Fracturing – Development	117,934	\$120	122,908	\$208
Hydraulic Fracturing - Exploration	9,979	\$4	10,284	\$12

2.4 CENTRIFUGAL AND RECIPROCATING COMPRESSORS

2.4.1 Compressor Control Costs

The control costs for routing a wet seal compressor vent to an existing control device was estimated by EPA to be \$23,252, as indicated in Section 2.2.1 above. We believe this cost to be more representative of the true uninstalled capital cost of the control option.

2.4.2 Compressor Emission Reduction Estimate

Overestimate of Centrifugal Compressor Baseline Emissions

EPA based the wet seal centrifugal compressor baseline emissions on the emission factors from the US GHG Inventory: Emission and Sinks 1990-2012. The emission factors for wet seal centrifugal compressors was based on a sampling of 48 wet seal centrifugal compressors, and derived from the emission rate and percent of time the compressor was in pressurized mode. According to the Interstate Natural Gas Association of America in comments to EPA on the Methane White Paper on Compressors,¹¹ the US national GHG inventory values are reported to be over 30 times higher than values found in Subpart W reporting. Since Subpart W reporting reflects recent industry practices, and is based on measured emission rates for compressors in transmission and storage, it is considered to be more accurate.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

EPA projected the number of new and modified reciprocating and centrifugal compressor sources for 2020 and 2025 based on the same approach used for pneumatic pumps. Specifically, EPA estimated the number of reciprocating and centrifugal compressor installations based on a 10 year average of compressor net increases from the inventory of US GHG Emissions and Sinks: 1990-2012. Only the years of positive net increase were averaged, neglecting the years of estimated decline in number of sources. This approach introduces significant uncertainty since a simple average over the same 10 year period (i.e., counting years of source declines) yields a negative change for centrifugal compressors in both transmission and storage segments and negligible increase for reciprocating compressors in the transmission segment. Table 7 shown below presents the difference between the approach EPA used and the simple 10 year average.

¹¹ INGAA. "INGAA to 'Environmental Protection Agency (EPA) Methane White Paper: Oil and Natural Gas Sector Compressors'", available at: <http://www.ingaa.org/File.aspx?id=21896>.

Table 2-5: Number of New Compressors in a Typical Year Used in Analysis

Segment	EPA Approach: 10 Year Average of Net Increases	10 Year Simple Average	EPA Approach: 10 Year Average of Net Increases		10 Year Simple Average	
	# New Reciprocating Compressors	# New Reciprocating Compressors	# New Centrifugal Compressors		# New Centrifugal Compressors	
			Wet Seal	Dry Seal	Wet Seal	Dry Seal
Transmission	24	0	0	2	-1	1
Storage	43	-17	1	5	-3	2

2.5 PNEUMATIC DEVICES

2.5.1 Pneumatic Device Emission Reduction Estimate

Overestimate of Pneumatic Device Baseline Emissions and Emission Reductions

EPA estimated that all bleed devices installed at transmission and storage stations are high bleed, because vendor research did not have enough information to estimate the prevalence of high- versus low-bleed devices. This assumption overstates the number of high-bleed devices and consequently, the nationwide baseline emissions and potential emission reductions achievable by replacing them with low-bleed devices.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

EPA projected the number of new and modified bleed pneumatic devices for 2020 and 2025 based on the same approach used for pneumatic pumps and compressors. Specifically, EPA estimated the number of new bleed devices based on a 10 year average of net increases from the inventory of US GHG Emissions and Sinks: 1990-2012. Only the years of positive net increase were averaged, neglecting the years of estimated decline in number of sources. This approach introduces significant uncertainty since a simple average over the same 10 year period (i.e., counting years of source declines) yields a negative change for bleed devices in the storage sector.

3.0 SOCIAL COST OF METHANE

The RIA used a paper by Marten et al. (2014) to determine the SC-CH₄ estimates. The RIA claims that the Marten approach is “consistent with” methods used to develop the SCC. This is important to the EPA, as the SCC has been approved for use in RIAs by OMB; to the extent that there is consistency of the SC-CH₄ with the SCC, then the imprimatur of the OMB may attach to the SC-CH₄. Given that OMB approval does not necessarily verify that the SCC provides a scientifically and economically defensible basis for a benefit-cost analysis, in this section we examine consistency between the SC-CH₄ and the SCC.

The methodology used by Marten et al. (2014) is similar to the IWG approach to estimating SCC in that it uses the same:

- Three IAMs;
- Five socio-economic and emissions scenarios;
- Discount rates; and
- Approach for averaging social costs across scenarios and IAMs.

One of the three IAMs, FUND, handles CH₄ explicitly. The other two IAMs, PAGE and DICE, were modified by Marten et al. using a simple CH₄ gas model to make it consistent across IAMs. The EPA asked three peer-reviewers to provide an assessment of the SC-CH₄ and concluded that the reviewers generally agree that the SC-CH₄ estimates are consistent with the SCC estimates.¹² Moreover, because OMB guidance supports the use of SCC estimates, the EPA decided that a finding concluding that the SC-CH₄ was consistent with SCC estimates justified the use of the SC-CH₄ estimates, and further stated that the SC-CH₄ estimates were an “analytical improvement” over their exclusion.

After reviewing the available data and studies, as well as the reviewers’ comments, ERM believes that the use of the SC-CH₄ estimates is not warranted at this time, for the following reasons:

1. The three peer reviewers’ endorsement of the “consistency” of the SC-CH₄ estimates was far more modest than the EPA asserts. Further, the reviewers identified key uncertainties with the approach being used.

¹² EPA. Whitepaper on Valuing Methane Emissions Changes in Regulatory Benefit-Cost Analysis, Peer Review Charge Questions, and Responses.

2. All of the challenges with estimating the SCC apply to estimating the SC-CH₄. These challenges seriously affect the scientific and economic reliability and usefulness of both the SCC and SC-CH₄ in the foreseeable future.
3. The SC-CH₄ (and SCC) estimates are highly uncertain and the causes of the uncertainty are not well understood.

3.1 MODEST PEER REVIEW ENDORSEMENT OF THE "CONSISTENCY" OF THE SC-CH₄ ESTIMATES

The EPA notes that benefit-cost analysis must provide estimates that are produced in a "scientifically and economically defensible manner". Interestingly, the seven charge questions from EPA to the peer reviewers did not directly ask whether the SC-CH₄ estimates are scientifically and economically defensible. Instead, the charge questions are concerned with: the consistency of the SC-CH₄ estimates with the SCC estimates; whether the latest direct SC-CH₄ estimates are better than SC-CH₄ estimates based on global warming potential (GWP); and whether better SC-CH₄ estimates currently exist. That the reviewers are never asked whether the SC-CH₄ estimates used in the RIA are reliable and appropriate for use in policy analysis is an important omission.

The EPA asserts that the reviewers generally agree that the SC-CH₄ estimation methods are consistent with SCC. This clearly is an overstatement. One reviewer agrees that the SC-CH₄ estimates are consistent with the SCC. However, a second reviewer offers this assessment:

The term "Consistent" can have many interpretations. I will say that the Marten et al. SC-CH₄ estimates are computed in a similar way as the SC-CO₂ estimates, so in this regard, the two estimates are "consistent." However, CO₂ is more explicitly modeled in the three models than CH₄ so in this regard they are not "consistent."

The reviewer goes on to point out that inconsistencies reflect the limitations of models and that there are gaps that need to be understood, despite the Marten et al. attempts to address them.

The third reviewer also expressed concerns about specific consistency issues. Although all of the damages for SCC and SC-CH₄ are reported on a per ton basis, the magnitude and duration of the perturbations that are used to estimate the damages vary across all of the IAMs for SCC and are different than what is used for SC-CH₄. For example, for SCC, DICE uses a one Giga-ton carbon shock over a decade, while Marten et al. use a 1 million ton shock in a single year. Similarly, the SC-CH₄ models that compute CH₄ concentrations and radiative forcing differ from PAGE's approach for non-CO₂ emissions. The implications of these differences are not well understood. More importantly, the reviewer believes that any consistency that does exist is a "serious problem", because it means the SC-CH₄ inherits all of the problems of the SCC

estimates. This reviewer also points out that while the Marten et al. paper has been peer-reviewed, the underlying IAM models and the multi-model averaging approach have not.

Thus, in our view, reliance upon the SC-CH₄ estimates based on their purported consistency with the SCC cannot be justified.

3.2 ALL OF THE CHALLENGES WITH ESTIMATING THE SCC APPLY TO ESTIMATING THE SC-CH₄

The challenges with using the SCC estimates are well documented. We summarize the key issues here.

EPRI (2014) provides an in-depth technical assessment of the SCC estimates. Their goal is to understand the key drivers of the damage estimates, the reliability of the results, and whether estimates can be improved. They focus on three areas: climate; emissions; and damages.

They find significant differences across the three IAMs in the predicted temperature change and sea level rise change from the same increase in emissions and same underlying socioeconomic conditions. The temperature responses result from differences in the modeling of the carbon cycle, non-CO₂ radiative forcing, and climate sensitivity. Even in the short-term, through 2040, the IAMs can yield temperature changes that vary across models by a factor of two for the same emissions scenario.

The economic damage functions linked to these temperature changes and sea level rise estimates are also very different. For example, one IAM shows gains in GDP through 2100 for some scenarios with increased emissions, while the other two IAMs show losses for the same scenarios and emissions. The three models also show wide variation in the impact on the GDP of different countries and for different types of economic costs (i.e., agriculture, heating and cooling). The damage functions themselves are arbitrary and not based on significant empirical data or economic theory (NERA 2014).¹³ For example, one can easily plot two damage functions that are both consistent with the few current data that are available, but which produce widely different damages in the distant future.

EPRI concludes that the significant differences in the structure of the models, which lead to significant differences in the damages estimates, are not well understood or explained. As a result, EPRI concludes that it is difficult to assess whether the

¹³ NERA. 2014. A Review of the Damage Functions Used in Estimating the Social Cost of Carbon. Comments prepared for the American Petroleum Institute.

differences reflect true scientific uncertainty (and therefore they should be retained) or the differences are topics that should be resolved and standardized.

The EPRI results also call into question the USG approach of averaging the SCC models across different socioeconomic scenarios to form a single estimate of the SCC for a particular discount rate. EPRI concludes that the inconsistencies in the models, the lack of robustness of the models, and the fact that they may not be truly independent may make such averaging inappropriate. In our view, such averaging may also be inappropriate because it assumes that each estimate is equally reliable and obscures the true uncertainty about the SCC that exists in the scientific literature. Gillingham et al. (2015) conclude that the concept of relying on an ensemble of models to capture total uncertainty is not theoretically sound and furthermore, based on their empirical data, is a “deficient” approach, because it fails to capture the full range of uncertainty that affects the models. Moreover, they believe their results highlight the importance of additional research on the role economic variables and damage functions to improve climate-change policy making.

EPRI provides six specific recommendations for improving public and scientific confidence in SCC estimates: conducting more detailed analyses of the differences among the IAMs to better understand and determine which differences and uncertainties to retain; additional peer review of the IAMs; integration (i.e., weighting of the results); better documentation of the approach; more complete justification on the methods; and guidance on their use.

Other reviewers have been even less enthusiastic. Pindyck's (2013) review of the IAMs led him to conclude:

These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g., the discount rate) are arbitrary, but have huge effects on the SCC estimates the models produce; the models' descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation; and the models can tell us nothing about the most important driver of the SCC, the possibility of a catastrophic climate outcome. IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading.

The SCC estimates' sensitivity to model parameters can also be found in the SC-CH₄ estimates. ERM obtained the DICE model, data and computer code from Dr. Marten. In our evaluation, we found that changing the parameter on temperature squared in the assumed damage function of the DICE model for SC-CH₄ by 0.000020405 (25%) changes the estimated SC-CH₄ for 2025 by \$200. Similarly, changing the global total factor productivity for the assumed process that generates output by 0.0075805 (25%) changes the SC-CH₄ by \$350. Our evaluation demonstrates that small changes in arbitrary functions have significant effects on SC-CH₄ estimates.

3.3 *THE SC-CH₄ ESTIMATES ARE NOT WELL UNDERSTOOD AND HAVE NOT BEEN FULLY VETTED*

As discussed above, the SCC estimates suffer from significant uncertainties about their sensitivity to the myriad assumptions embedded in the models, the impacts of which are poorly understood. These same uncertainties also plague the SC-CH₄ estimates and are understated in the RIA. The uncertainties undermine the usefulness of resulting values in benefit-cost analysis at this time.

First, the degree of uncertainty in the estimates is unrepresented in the RIA. For any discount rate and emission year, the RIA reports the SC-CH₄ as a single number. However, looking across the IAM models reveals a significant range of potential values. For example, for a 3 percent discount rate and incremental emissions occurring in 2020, the SC-CH₄ is reported as \$1,200 in Marten et al. However, Appendix B of the Marten et al. paper indicates that across the 3 IAMs and 5 socioeconomic policy scenarios (including the scenario average), the average SC-CH₄ is \$1,200 with a standard deviation of \$251 (or approximately 20 percent of the average value). However, even this range underreports uncertainty. Each of those 15 estimates (i.e., 3 IAMs and 5 scenarios) is the average of 10,000 Monte Carlo simulations. Looking across the entirety of the SC-CH₄ estimates from these simulations yields a standard deviation of \$1,720, 138 percent of the average SC-CH₄, nearly 6 times as high.

It is critical that the causes of variability of the SC-CH₄ estimates be fully understood before they are used in policy analysis. As the authors of the FUND model note, many of the assumptions about the appropriate distributions that should be used to characterize the uncertainty are expert “guesses” (Anthoff, et al. 2014)¹⁴. Furthermore, in another paper Anthoff reports that parameters on cooling energy demand, migration, climate sensitivity, and agriculture are uncertain and have a significant impact on model results, but the first two have not been largely researched (Anthoff, et al. 2013).¹⁵

EPA benefit cost-guidance also recommends providing undiscounted values, which would provide more insights into the issues surrounding uncertainty and the appropriate discount rate. (EPA 2010, pp. 6-18). However, that data was not discussed in the RIA.

¹⁴ Anthoff, D., et. al. 2014. The Climate Framework for Uncertainty, Negotiation and Distribution (FUND), Technical Description, Version 3.9. Accessed on the FUND Website, November 2014.

¹⁵ Anthoff, D., Richard T. 2013. The uncertainty about the social cost of carbon: A decomposition analysis using FUND.

ERM estimated the undiscounted benefits for the four socioeconomic scenarios using the DICE model. Modifying Dr. Marten's computer code, we produce the undiscounted social costs by year for 1 ton emission of CH₄ that occurs in 2025 and 2045, and calculate the percentage of total social costs occurring before and after year 2100. Table 3.1 shows the results of our evaluation. The results show that the vast majority (\$4 out of every \$5 dollars) of social costs associated with methane emissions after the year 2100, which is the time period for which the temperature rise, baseline emission, and socio-economic projections are speculations at best. Higher discount rates effectively shorten the time period that are included in the benefits estimates.

Table 3-1. Percent of Undiscounted Social Costs of Methane Occurring Before and After 2100 (2007\$)*

Socio-economic Model	Emission in 2025		Emission in 2045	
	Percent 2100 and Earlier	Percent after 2100	Percent 2100 and Earlier	Percent after 2100
Image	12%	88%	13%	87%
Merge	19%	81%	21%	79%
Message	20%	80%	21%	79%
MiniCam	10%	90%	12%	88%

*Climate sensitivity parameter set to 3.

The potential role of discount rates is also important because of the supposed global nature of the benefits. While lower discount rates may be the norm for the U.S. and developed countries, the discount rates for other countries (who will enjoy most of the benefits) may be significantly higher. For example, Lopez (2008) reports that a social discount rate for nine Latin American countries could range from 3 to 7 percent, depending on future growth rates¹⁶. Florio and Sirtori (2013)¹⁷ report that discount rates being used throughout the world range from 3 to 15 percent. Therefore, if the EPA prefers to illustrate their estimated global benefits, they should base them on global discount rates. Moreover, a 7 percent discount rate is still the preferred rate regulatory impact analysis by the OMB and should be included in the RIA for the required analysis of domestic benefits (OMB, 2003)¹⁸.

To better understand the impact of using a higher discount rate, we estimated SC-CH₄ using the DICE model. The results show that moving to the 7 percent discount rate reduces the SC-CH₄ estimates by over two-thirds (Table 3-2). Technically, this result

¹⁶ Lopez, Humberto. 2008. The Social Discount Rate: Estimates for Nine Latin American Countries. http://www.researchgate.net/publication/23723498_The_Social_Discount_Rate_Estimates_for_Nine_Latin_American_Countries

¹⁷ Florio and Sirtori. 2013. "The Social Cost of Capital: Recent Estimates for the EU Countries." Centre for Industrial Studies. Working Paper Series. http://www.csilmilano.com/docs/WP2013_03.pdf

¹⁸ OMB. 1992. Circular No. A-94. Revised.

only applies to the DICE model. However, if the same percentage decline is applied to the 2020 SC-CH₄ EPA used in the RIA, the value would drop from \$1,300 to \$403.

Table 3.2. Impact of Discount Rates on SC-CH₄ in the DICE Model (2007\$)

Emission Year	3 Percent Discount Rate	7 Percent Discount Rate	Difference (%)
2025	\$974	\$311	-\$641 (-68%)
2045	\$1,658	\$598	-\$1,059 (-64%)

*Climate sensitivity parameter set to 3. SC-CH₄ values are the average across the four socio-economic scenarios).

4.0 UNCERTAINTY ANALYSIS

The RIA did not adequately consider the uncertainty of both the benefits and the costs associated with the NSPS OOOOa. Both EPA guidelines (EPA, 2010) and OMB guidelines (OMB, 2003) indicate that evaluating the impact of uncertainty on benefits and costs is a key consideration in rule making. Moreover, the OMB explicitly states that when the degree of uncertainty has a significant impact on net benefits, agencies should consider conducting additional research prior to rulemaking. Instead of including plausible ranges for the key benefits and costs and acknowledging the uncertainty about the true values of underlying parameters and assumptions, EPA relied upon point-estimates for costs and benefits. As a result, the RIA gives an unrealistic assessment of the impact of the proposed rules.

ERM developed a Monte Carlo model to provide a more realistic assessment of the net benefits of the NSPS OOOOa. Monte Carlo simulation is a standard method for evaluating the impact of regulations when there is substantial uncertainty. It provides insights into the likelihood that benefits will exceed costs when there are multiple parameters and assumptions that are uncertain.

ERM developed the Monte Carlo model for five emission sources/points:

- Hydraulically fractured development oil well completions,
- Hydraulically fractured exploration oil well completions,
- Fugitive emissions from oil wells,
- Fugitive emissions from natural gas wells, and
- Pneumatic pump operations at well sites.

These emissions sources/points comprise over 90 percent of the control costs and over 80 percent of the controlled emissions EPA estimates.

The model is estimated by calculating costs and benefits for 5,000 draws from the probability distributions for the values of parameters and assumptions underlying the quantification of the number of regulated units, control costs, emission control volumes, natural gas recovery revenue and SC-CH₄.

ERM's Monte Carlo analysis provides a more complete analysis of the net benefits. The results show that there is significant uncertainty about the costs and benefits of the proposed rule and that it is likely that costs will exceed benefits, especially when considering the net benefits accruing to the U.S.

The cumulative probability distribution functions (CDF) and 90 percent confidence interval for costs, benefits and net benefits in 2025 (i.e., a 90 percent change the true

value is actually within that range) from all emissions sources/points are presented in Figure 4-1. The average 2025 global net benefit estimate is -\$0.5 billion with a standard deviation of \$0.41 billion. The degree of variation in net benefits means that there is a 90 percent chance that true global net benefits will be between -\$0.92 and \$0.17 billion. Based on the distribution, there is an 89 percent chance that net benefits in 2025 are lower than EPA's own estimate (uncorrected) of \$0.12 billion. The difference is starker when considering that somewhere between 7 and 23 percent of methane control benefits accrue to the United States. Based on the model, there is a 90 percent chance that net benefits for the U.S. will range between -\$1.07 and -\$0.56 billion.

Figure 4-1. Estimated Costs, Benefits and Net Benefits of the NSPS OOOOa Under Uncertainty for All Emissions Points and Sources (\$MM)

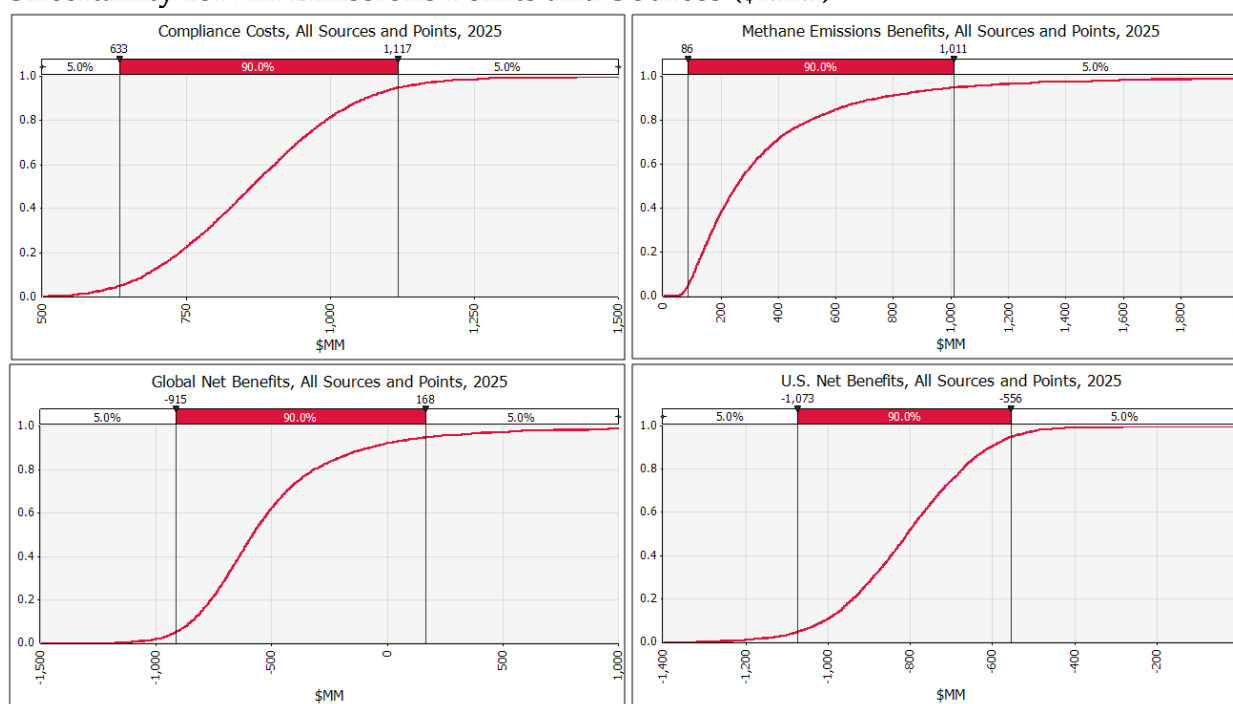


Table 4-1 summarizes the distributions of costs, benefits and net benefits in 2025 generated by ERM's Monte Carlo model for each emission source/point evaluated, compared with EPA's estimate. EPA's estimated costs are always towards the lower end of the distribution, while estimated benefits are well above the median. This implies that EPA's costs and benefits are less probable rather than more probable. For many emissions sources, EPA's estimated net benefits are positive, whereas net benefits are negative at the middle of the distributions generated by ERM's model. One example of this is fugitive emissions controls at gas wells. EPA's estimated 2025 net benefits are \$0.62 billion, whereas the median of ERM's distribution is -\$0.12 billion.

Table 4-1. Estimated Costs, Benefits and Net Benefits of the NSPS OOOOa Under Uncertainty for Selected Emissions Sources and Points (\$MM)

Source	Point	Costs				Benefits				Global Net Benefits				U.S. Net Benefits	
		5 th	50 th	95 th	EPA	5 th	50 th	95 th	EPA	5 th	50 th	95 th	EPA	50 th	EPA
Well Completions	Development	153	199	243	120	18	143	429	173	-197	-55	241	53	-182	-94
	Exploration	7	11	15	4	1	8	37	14	-11	-3	25	10	-9	-2
Fugitive Emissions	Oil Wells	240	391	579	120	5	24	117	51	-547	-355	-192	-69	-386	-112
	Gas Wells	104	179	277	46	11	53	255	108	-222	-115	78	62	-168	-30
Pneumatic Pumps	Well Pads	26	52	78	5	2	10	51	39	-68	-38	4	34	-50	1

In the following sections, we describe parameters and assumptions underlying the estimates of total costs and benefits, and the probability distributions fit to those ranges to implement the Monte Carlo simulation.

4.1 METHANE EMISSION BENEFITS

EPA used the SC-CH₄ estimate from Marten et al. 2014 based on the 3 percent discount rate to report monetary benefits of methane emission reductions. While EPA “emphasiz[ed] the importance and value of considering the benefits calculated using all [four] SC-CH₄ estimates”, the RIA did not report a comparison of benefits and costs using the wide-range of SC-CH₄ estimates derived by Marten for alternative policy scenarios, IAMs and discount rates (RIA, Table 1-4, Note 1).

Using Monte Carlo methods, Marten generated 10,000 estimates of SC-CH₄ for each of four future economic policy scenarios (excluding the overall policy-average) simulated using each of the three IAMs and three discount rates (i.e. 36 combinations)¹⁹ For each combination, the SC-CH₄ is future social costs for an additional 1 ton of methane emitted in a particular year discounted back to 2012 at each of the three alternative discount rates. The 10,000 estimates for each combination are based on uncertainty parameters embedded in each IAM. In using the Marten et al. results, the RIA calculated the overall average SC-CH₄ from the IAM and policy distributions separately

¹⁹ The economic policy scenarios are IMAGE, MERGE, MESSAGE and MiniCAM.

for each of the three discount rates. The EPA focused on the overall average SC-CH₄ for the 3 percent discount rate to value benefits of methane emission controls for the RIA.²⁰

ERM obtained Dr. Marten's Monte Carlo simulations for this evaluation. The data reveal the significant uncertainty in the SC-CH₄, and underscore the inappropriate nature of using only average values of SC-CH₄. Table 4-2 summarizes Marten's distributions of the 2020 SC-CH₄ within each IAM, varying by policy scenario and using the 2.5 and 5.0 percent discount rates.²¹ Each of the distributions is skewed towards higher estimates of SC-CH₄. The mean estimate exceeds the median estimate by 33 to 140 percent. The FUND and PAGE models are characterized by an enormous degree of variability. Overall, the estimated SC-CH₄ typically varies by more than 230 percent of the mean, ranging from 75 to 310 percent across IAMs. FUND generates extreme lower and upper bounds (social benefit or costs of methane), ranging from over -\$0.5 to \$0.25 million per ton.

Table 4-2. Empirical Distributions of SC-CH₄ in 2020 Developed by Marten et al. 2014 (2007\$ per ton)

IAM	N	Mean	Median	Standard Deviation	Range (Min / Max)	
DICE	80,000	858	645	636	101	3,729
FUND	80,000	1,341	978	4,157	-679,393	225,935
PAGE	80,000	1,305	544	2,119	-11	28,645
Overall	240,000	1,168	708	2,728	-679,393	225,935

ERM used Marten's empirical distributions to model uncertainty in methane emissions benefits, but we used a different approach than the RIA.²² Using all 240,000 SC-CH₄ estimates, we found the single probability distribution function that best described the data. The probability distribution we used is a log-normal distribution with a mean of \$1,236 and a standard deviation of \$1,439 per ton (2012\$).²³ This provides a single function that characterizes uncertainty across IAMs, policy scenarios, and discount rates. ERM estimated the 2025 SC-CH₄ by multiplying each draw of the 2020 SC-CH₄ by 1.162.^{24, 25} This approach more fully captures the degree of uncertainty than the RIA

²⁰ EPA averaged means of the SC-CH₄ distribution over policy scenario within each IAM, and then over IAMs, generating a point-estimate for each discount rate. EPA also averaged the 95th percentile of the SC-CH₄ for the 3 percent discount rate. The 2020 SC-CH₄ that EPA reported in the RIA ranged from \$580 to \$3,500 per ton across the three discount rates and the 95th percentile of the distribution from the 3 percent rate (RIA Table 4-3).

²¹ ERM discarded the distributions for the 3.0 percent discount rate because they are bounded distributions for the 2.5 and 5.0 percent discount rates.

²² ERM obtained the distributions directly from Dr. Marten.

²³ ERM inflated Dr. Marten's SC-CH₄ estimates from 2007\$ to 2012\$ using the GDP implicit price deflator.

²⁴ @Risk Formula: RiskLognorm(1235.9,1438.7,RiskShift(-15.64)).

²⁵ This scalar reflects the ratio of the 2025 to 2020 policy- and IAM-average SC-CH₄ the EPA derived from Marten et al 2014 using the 2.5 and 5.0 percent discount rates (RIA Table 4-3). This method eliminates draws where the SC-CH₄ in 2025 is less than the SC-CH₄ in 2020.

approach, but does not capture the full range that might exist as described by Gillingham et al. (2015).

EPA estimated the monetary benefits of methane emissions associated with the NSPS OOOOa by multiplying the SC-CH₄ by tons of controlled methane emissions. Total controlled methane emissions are derived by multiplying controlled emissions per regulated unit by the number of regulated units.

Table 4-3 reports the range of uncertainty about per unit methane emission reductions that ERM used in the Monte Carlo model. As described in Section 2, EPA over-estimated per unit methane emission reductions for several emission sources/points. Unless otherwise noted, ERM used EPA's estimate as the upper bound, ERM's corrected estimate as the most likely value, and 70 percent of ERM's estimate as the lower bound of a Beta-PERT probability distribution.

Table 4-3. Distribution of Annual Controlled CH₄ Emissions Used in ERM's Monte Carlo Model

Emission Source/Sector	Units	Min.	Most Likely	Max.	Notes
Fracking Well Completions ^a	Mt/ completion	6.46	9.23	12.00	Most Likely: EPA. Min/Max: +/- 30% of EPA estimate.
Fugitive Emissions / Oil Wells	Mt/ well site	0.29	0.42	0.65	Max: EPA estimate (baseline 1.09 x 40% reduction). Most Likely: EPA estimate after eliminating compounded rounding and revised methane concentration for oil wells (Table 2-3). Min: Most Likely x 0.7.
Fugitive Emissions / Natural Gas Wells	Mt/ well site	1.34	1.91	2.72	Max: EPA estimate (baseline 4.54 x 40% reduction). Most Likely: EPA estimate after eliminating compounded rounding (Table 2-3). Min: Most Likely x 0.7.
Pneumatic Pumps / Diaphragms (O&G Wells)	Mt/pump	0.72	1.03	3.29	Max: EPA estimate. Most Likely: Operational for 4 months per year to reflect seasonal use and revised methane concentration for oil wells (Table 2-3). Min: Most Likely x 0.7.
Pneumatic Pumps / Pistons (O&G Wells)	Mt/pump	0.24	0.34	0.36	Max: EPA estimate. Most Likely: Revised methane concentration for oil wells. Min: Most Likely x 0.7.

^a The emission reductions are multiplied by a scalar ranging from 0.75 to 1.0 to reflect that up to 25 percent of development oil wells are already controlled.

4.2 PROJECTED SCOPE OF REGULATION

Total costs and benefits associated with NSPS OOOOa increase with the number of new and modified emissions sources projected in 2020 and 2025. EPA projected growth of sectors and market segments within the oil and gas industry using historical data, but

did not consider the considerable variability of annual growth and inventories of units subject to the regulation apparent from the very data utilized. For example, by choosing to exclude years of contraction, EPA projected 581 new pneumatic storage devices annually over 10-years when the actual average annual growth was -230 devices. Had they assumed growth was 0 during those years of contraction (i.e. included all years in the denominator but only positive values in the numerator), EPA would have projected 232 new devices annually. By failing to recognize uncertainty in annual growth within elements of the oil and gas industry, EPA has given a false sense of precision about the total cost impact and societal benefit associated with NSPS OOOOa.

Tables 4-4, 4-5 and 4-6 report the ranges in parameters ERM used to model uncertainty in the number of regulated units existing in 2020 and 2025. Unless otherwise noted, ERM used EPA's estimate as the most likely value and developed the range as +/- 30 percent. ERM modeled the probability distribution of all but the parameters for new CIPs (pneumatic pumps) using the Beta-PERT distribution.

Table 4-4. Range in Inputs for Projected Fracking Well Completions Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
Oil Well Completions, 2012	14,357	14,357	14,357	Used EPA estimate.
Fraction Exploration Wells (%)	2.66	3.8	4.94	
CAGR of Developmental Wells (%/yr)	-0.007	-0.005	-0.004	
CAGR of Exploration Wells (%/yr)	4.2	6.0	7.8	

Table 4-5. Range in Inputs for Projected Oil & Gas Well Pads Subject to Fugitive Emissions Regulations Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
Well Density (# Wells/Pad)	1	1.81	2	Max: EPA estimate, rounded. Most Likely: EPA estimate unrounded. Min: 0.7 x Most Likely.
Oil Wells				
Unregulated Oil Wells, 2012 (# wells)	22,599	32,284	41,969	
Low-Producing Oil Wells (%)	31	43	59	
Oil Well Growth (%/yr)	0.22	0.32	0.42	
Natural Gas Wells				
Unregulated NG Wells, 2012 (# wells)	4,683	6,691	8,698	
Low-Producing NG Wells (%)	21	30	39	

NG Well Growth (%/yr)	3.0	6.45	8.39	Most Likely: EPA estimate. Min: EPA estimate used in Gathering & Boosting analysis. Max: Most Likely x 1.3
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Table 4-6. Range in Inputs for Projected Pneumatic Pumps at Oil & Gas Well Pads Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
New CIPs-Oil Wells (#/yr)	0	803	1,400	*Triangular distribution. Most Likely: EPA estimate. Min/Max: Min/Max of historical data on annual new oil well CIPs.
New CIPs-NG Wells (#/yr)	800	1,500	2,200	*Triangular distribution. Most Likely: EPA estimate. Min/Max: +/- 1 std. deviation of the fitted distribution to historical data on annual new gas well CIPs.
Replaced CIPs-All Wells (#/yr)	476	680	884	
Fraction Diaphragm (v. Piston) (%)	25	50	75	Most Likely: EPA estimate. Min/Max: ranges used by EPA in similar analysis.

4.3 COMPLIANCE COSTS

EPA estimated total compliance costs by multiplying the projected number of regulated units by unit compliance costs. Tables 4-7, 4-8 and 4-9 report the ranges in the unit cost parameters ERM used to model uncertainty in compliance costs. The most likely value of the distribution for annualized costs and/or underlying parameters is most commonly the value ERM derived by correcting technical flaws in EPA's costing and finding estimates for key elements of costs omitted by EPA, as described in Section 2. Unless otherwise noted, EPA's estimate is the lower bound, while the upper bound is a 30 percent increase in the most likely value. We use the Beta-PERT distribution to model uncertainty.

Table 4-7. Range in Inputs and Distribution of Hydraulically Fractured Well Completions Control Costs Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Capital Costs					
REC & Combustion	\$/completion	17,183	23,459	30,497	
Combustion only	\$/completion	3,723	10,000	13,000	
Fraction REC & Combustion (Development Wells)	%	35	50	65	
Useful Life	# Yrs.	1	1	1	
Annualized Cost – Development Wells	\$/completion	6,944	16,729	21,606	
Annualized Cost –	\$/completion	3,723	10,000	13,000	

Exploration Wells					
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Table 4-8. Range in Inputs and Distribution of Fugitive Emissions Control Costs at Oil and Natural Gas Well Sites Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Well Sites Density	wells/site	15.4	22	28.6	
Annualized Cost	\$/well site	2,230	6,353	8,259	Min.: EPA estimate. Most Likely: ERM estimate based on CO Regulation 7. Max.: 1.3 x Most Likely.

Table 4-9. Range in Inputs and Distribution of Pneumatic Pumps Control Costs at Oil and Natural Gas Well Sites Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Route to existing flare	\$/CIP	1,966	23,252	30,228	
Useful Life	# Yrs.	10	10	10	
Annualized Cost	\$/CIP	280	3,308	4,304	

4.4 NATURAL GAS SAVINGS

Where appropriate given the nature of the sector, EPA deducts revenue associated with natural gas recovered from avoided methane emissions from emission control costs.²⁶ EPA valued estimated natural gas recovered at a price of \$4.00/Mcf. Using a point estimate fails to recognize the inherent volatility of commodity markets, as demonstrated by the current landscape of and outlook for oil and gas commodity prices.

²⁶ EPA estimated the recovered volume by scaling tons of controlled methane emissions by specific technical factors. ERM's Monte Carlo model does not model uncertainty around these technical factors. Rather, uncertainty in recovered volumes is function of uncertainty in the volume of controlled emissions.

Attachment F

Comparison of the LDAR Requirements Proposed in
Subpart OOOOa to Existing State LDAR Programs

Comparison of OOOOa Requirements to Colorado Regulation 7, Wyoming Chapter 8, Ohio General Permit requirements, and Pennsylvania Permit requirements.

Highlighted cells indicate where the proposed OOOOa requirements are more stringent than the state level requirements.

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
60.5397a(a)	Monitor all fugitives as defined	Fugitive components not as extensive as OOOOa			
60.5397a(b)	Develop a corporate-wide monitoring plan (MP)	No MP requirement	LDAR protocol by 1/1/2017 for each facility	LDAR program should be developed & implemented. No deadline.	No MP requirement
60.5397a(c)(1)	MP: Specify monitoring frequencies	In Rule, based on emission actuals	Rule states no less frequently than quarterly	Rule states no less frequently than quarterly for 4 consecutive quarters.	Requires quarterly LDAR
60.5397a(c)(2)	MP: Technique for determining fugitive emissions	Not clear	No	No	Not required
60.5397a(c)(3)	MP: Manuf and Model of detection equipment	Not required	Not required	FLIR or an analyzer meeting USEPA Method 21 or 40 CFR 60, Appendix A	Not required
60.5397a(c)(4)	MP: procedures and timeframes for ID and repair detections	5 days to fix	No	No	Within 15 days otherwise DOR
60.5397a(c)(5)	MP: procedures and timeframes for verifying repairs	Rule specific monitoring timeframes (15 d to re-monitor after the	No	No	Leak must be demonstrated as repaired

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
		fix)			
60.5397a(c)(6)	MP: Length of time records will be kept	Two Years	Five yrs.	Five yrs.	Five yrs.
60.5397a(c)(7)(i)(A),(B)	MP: Third party verification of IR camera	Not required	Not required	Not required	Not required
60.5397a(c)(7)(ii)	MP: Procedure for daily verification check	No	No	No	No
60.5397a(c)(7)(iii)	MP: Procedure for determining max viewing distance	No	No	No	No
60.5397a(c)(7)(iv)	MP: Procedure for determining max wind speed to conduct survey	No	No	No	No
60.5397a(c)(7)(v)(A)	MP: How operator will ensure adequate thermal background	Not required	Not required	Not required	Not required
60.5397a(c)(7)(v)(B)	MP: How operator will deal with adverse conditions (wind)	Not required	Not required	Not required	Not required
60.5397a(c)(7)(v)(C)	MP: How operator will deal with interferences (steam)	Not required	Not required	Not required	Not required
60.5397a(c)(7)(vi)	MP: Training and XP prior to performing surveys	Not required	Not required	Not required	Not required
60.5397a(c)(7)(vii)	MP: Procedures for calibration and maint. Must comply with manufacturer	Not required	Not required	Same	Same
60.5397a(d)	Site Specific Monitoring Plan (SMP)	Not required	LDAR protocol by 1/1/2017 for each facility	Not required	Not required
60.5397a(d)(1)	SMP: Deviation from MP	Not required	Not required	Not required	Not required
60.5397a(d)(2)	SMP: Site Map	Not required	Not required	Not required	Not required
60.5397a(d)(3)	SMP: Defined Walking Path	Not required	Not required	Not required	Not required
60.5397a(e)	Each survey shall observe each fugitive component	Same	Same	Rule states each ancillary component with FLIR	Same
60.5397a(f)(1)	Initial survey NEW well site: 30d of first well completion or upon startup	Initial survey between 15-30 days of commencing	Not required	90 days of startup & quarterly thereafter.	w/in 60 d of startup

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
		operation			
60.5397a(f)(1)	Initial survey Modified well site: 30d of modification	Applies to existing and new sites	Not required	Not required	w/in 60 d of modification
60.5397a(f)(2)	Initial survey NEW Comp Sta.: 30d of startup	Within 90 days or 30 days of startup depending on fugitive emissions	Not required	Not required	w/in 180 d of startup
60.5397a(f)(2)	Initial survey Modified Comp Sta.: 30d of modification	Initial survey between 15-30 days of commencing operation	Not required	Not required	w/in 180 d of modification
60.5397a(g)	After Initial Survey, Semiannual, at least 4 months apart	No	Not required	Rule has conditions (i.e. < 2.0% leakers for 4 quarters)	Annual for Well sites, Quarterly for Comp Sta
60.5397a(h)	2 Consecutive Semi > 3% leakers, then quarterly	Frequency based on emissions not leakers	Not required	Any 1 semi-annual or annual >2.0% leakers, then quarterly	Annual for Well sites, Quarterly for Comp Sta
60.5397a(i)	2 Consecutive Semi < 1% leakers, then annually	Based on emissions not leakers, Annual evaluation of emissions for step-downs	Not required	No, 2 Consecutive Semi < 2% leakers, then annually	Annual for Well sites, Quarterly for Comp Sta
60.5397a(i)	2 Consecutive Qtrly or Annual 1% - 3% leakers, then semiannually	No, only modification	Not required	Not required	Annual for Well sites, Quarterly for Comp Sta
60.5397a(j)(1)	Repair replace within 15 days of find. If infeasible, then next shutdown or within 6 mos.	Repair within 5 days not 60/shutdown requires, Otherwise delay of repair	Not required	1st attempt w/in 5 calendar days, must be repaired w/in 30 days of find.	Yes, but no shutdown w/in 6 months requirement,

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
					just repair at next shutdown
60.5397a(j)(2)	Resurvey within 15 days of find.	No, 15d after fix	Not required	No	Yes, to verify repair
60.5397a(j)(2)(i)	For repair not during survey when found, Method 21 or IR survey with 15days of finding.	M21 or IR.	Not required	Not required	Yes M21 or IR. Leak Detector and soap are also allowed
60.5397a(j)(2)(ii)(A)	If M21, resurvey <500ppm	Same requirement	Not required	Not required	Yes
60.5397a(j)(2)(ii)(B)	If M21, resurvey using 60.5401a(g)	No, soapy water allowed	Not required	Not required	No, soapy water allowed
60.5397a(j)(2)(iii)(A)	If IR, repair is no indication using IR	Same requirement	Not required	Not required	Same requirement
60.5397a(j)(2)(iii)(B)	If IR, Does this require a resurvey entire facility [60.5397a(a)] - all fugitives as defined?	No	No	No	No
60.5397a(k)	Recordkeeping (RK)	Same requirement	Same requirement	Yes	Yes
60.5397a(k)(1)	RK: Date of Survey	Same requirement	Same requirement	Yes	Yes
60.5397a(k)(2)	RK: Beginning and End time of Survey	Not Required	Not required	Not required	Not required
60.5397a(k)(3)	RK: Name of Operator performing Survey. Note training and experience of operator	Not Required	Not required	Yes to Name, No to requirement on training and/or experience	Not required
60.5397a(k)(4)	RK: Ambient Temp, Sky Cond, Max wind speed at time of survey	Not Required	Not required	Not required	Not required
60.5397a(k)(5)	RK: Note any Deviation from MP, or a statement no deviation were made	Not Required	Not required	Not required	Not required
60.5397a(k)(6)	For each finding (LK)	--	--	--	--
60.5397a(k)(6)(i)	LK: Location	Not Required	Not required	Not required	Not Required
60.5397a(k)(6)(ii)	LK: Digital Photo w/Lat/Long	Not Required	Not required	Not required	PA is requesting

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
					but not in rule
60.5397a(k)(6)(iii)	LK: Date of successful repair	Same requirement	Not required	Same requirement	Same requirement
60.5397a(k)(6)(iv)	LK: Instrument used to resurvey	Specify type of instrument used in inspection	Not required	Not required	Yes
60.5397a(l)	Meet reporting requirements 60.5420(b)(7)	State Annual Report, Aggregated Summary	LDAR Protocol, if applicable, by 1/1/2016	Specific requirements included	Submit Initial Compliance Report within 6 months

EF_W_FACILITY_OVERVIEW.FACILITY_NAME	EF_W_FACILITY_OVERVIEW.FACILITY_ID	EF_W_FACILITY_OVERVIEW.INDUSTRY_SEGMENT	Basin	Wellhead	Separators	Meters/piping	Compress	In-line heaters	Dehydrators	Heater-treater	Header
J. Cleo Thompson & James Cleo Thompson, Jr. LP, 430 Permian Basin	1007037	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	736	132	251	4	0	2	99	0
ConocoPhillips Permian (430)	1007039	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	266	369	176	44	11	0	30	84
EF Energy LP& 430 Permian Basin	1007777	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	391	192	391	11	1	1	80	391
Oxy Permian Basin - 430	1008141	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	14961	4721	0	73	180	0	1294	1646
Cimax Energy Permian DEC	1008290	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	387	599	146	13	85	0	132	143
Owintx USA Inc. - Permian Basin	1008351	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1553	587	0	2	0	0	235	1542
EOG Resources Inc. 430 Permian Basin	1008351	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	59	78	28	4	20	0	5	14
Approach Operating LLC 430 Permian Basin	1008456	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	824	734	638	9	18	0	47	153
Cimax Energy Co. 430 Permian	1008544	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	67	114	31	2	0	0	31	7
Pioneer Natural Resources USA Inc. Permian	1008607	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	6637	313	26	0	0	0	440	421
BPX Energy Permian Basin A&P Basin 430	1008632	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	292	100	229	0	0	0	78	0
Basin 430 West Texas - OCP	1008642	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	130	204	0	0	0	0	59	52
Cimax Energy Co. of Colorado 430 Permian	1008700	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1248	1264	304	72	0	0	680	144
Tendland Petroleum LP - 430 Permian Basin	1008788	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	743	295	585	3	0	0	210	735
Summit Petroleum LLC	1008890	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	630	373	1	3	0	0	211	70
Compass Production Partners LP - Permian Basin 430	1008959	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	440	455	440	0	0	0	99	0
Henry Resources LLC	1008998	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	336	276	124	1	0	0	54	120
WPX Energy Permian LLC	1009039	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	340	320	59	9	37	0	115	256
Laredo Petroleum Basin 430	1009056	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	962	271	0	0	0	0	235	63
Whiting Oil and Gas Corporation 430 Permian Basin	1009192	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	171	102	8	0	11	0	53	2
Chevron MCA 430 Permian Basin	1009240	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	3993	759	446	73	101	1	189	446
Unit Petroleum 285 Permian Basin	1009339	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	126	126	71	3	0	0	0	0
XTO Energy Inc 430 Permian	1009390	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	4032	2218	651	84	29	0	189	284
Apache Corp. Permian - Permian Basin 430	1009391	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	2345	1107	0	0	85	0	572	404
Diamondback E&P LLC	1009434	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	5283	2128	0	0	0	0	730	1253
SM Energy (Basin 430) Permian Basin	1009674	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	425	310	160	11	0	0	94	425
430 Permian Basin - CEP Energy Company	1009681	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	369	361	0	0	0	0	50	46
COG Operating LLC - 430 Permian Basin	1009707	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	5088	2906	1424	571	0	10	1273	925
Breitbart Operating LP 430 Permian	1009813	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	419	46	3	10	14	0	42	32
Permian Basin	1009846	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	2068	473	47	92	157	0	359	0
Primus Operating Corp 430 Permian Basin	1009885	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	115	287	0	0	0	0	180	0
Discovery Natural Resources LLC - 430 Permian Basin	1010294	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1241	961	1242	44	0	1	227	0
Halcon Operating Co. Inc. 430 Permian Basin	1010372	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	126	119	13	10	0	2	52	113
Permian Operations - Shell Exploration & Production Company	1010588	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	181	522	28	2	16	0	91	112
Gurlett Oil Co. Inc. 430 Permian Basin	1010784	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	201	18	0	0	0	0	20	0
Legacy Reserve Basin 430	101408	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	207	1667	750	2	0	0	263	1565
Burnitz 430 (Permian)	1011519	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1454	376	636	13	0	0	50	0
Parsley Energy Inc. 430 Permian Basin	1011555	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1565	1881	316	121	2	9	411	316
Endovox Energy Resources LP 430 Permian Basin	1011659	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	4018	2902	186	0	0	37	3318	1972
Stanford Production LLC	1011662	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	1122	989	365	19	0	2	26	365
Centennial Resource Production LLC	1011690	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	369	785	45	97	1	0	81	0
Resolute Natural Resources Company LLC 430 Permian Basin	1011735	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Apache Corporation + 430 - Permian Basin	1011803	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	121	74	0	0	0	0	2	12
Matador Production Company - Permian Basin	1012068	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Permian Basin Operations	1012098	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	550	536	0	0	0	0	136	441
POC Permian Inc. 430 Permian Basin	1012376	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	32	102	22	26	0	0	0	0
Blackboard Operating LLC - 430 Permian Basin	1012449	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	660	260	600	20	0	0	154	0
Jagged Peak Permian Basin (430) Operations	1012542	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Sable Permian Resources LLC - Basin 430	1012556	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	704	741	0	0	0	0	260	152
FOL Operating LLC 430 Permian Basin	1012666	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	137	62	0	0	0	0	20	0
Permian Basin Oil and Gas Production Facilities	1012780	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	257	11	257	46	0	0	0	8
Parsons Oil Permian (A&P) Basin Number 430	1013018	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	170	314	168	73	0	0	138	31
Surge Energy 430 Permian Basin	1013106	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	684	273	0	0	0	0	203	0
Callon (Permian) LLC - Basin 430	1013155	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	87	12	0	0	0	0	0	68
Oxy Energy Inc. - Permian Basin 430	1013222	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	263	217	0	0	0	0	194	23
Chisholm Energy 430 Permian Basin	1013241	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	107	107	104	34	20	0	18	0
DEO Operating LLC - Permian Basin (430) Operations	1013303	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	317	118	15	0	0	0	184	0
Felix Energy Holdings III LLC	1013342	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	186	20	0	20	0	1	153	98
Rosenthal Resources	1013377	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	122	137	0	0	0	0	20	99
Oasis Petroleum Permian LLC	1013393	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	15	5	2	0	0	0	0	0
Birch Resources	1013407	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	307	127	0	0	0	0	216	150
White Rock Oil & Gas LLC - 430 - Permian	1013412	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	500	118	163	9	4	2	4	335
Abralex Petroleum 430 Permian Basin	1013417	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	85	133	36	14	11	0	30	0
Earthstone Energy 430 Permian	1013483	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	84	197	0	58	0	1	67	0
Tal City Operations III LLC	1013606	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Scale Energy LLC - 430 (Permian Basin)	1013626	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Spur Energy Partners LLC-Permian Basin	1013674	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	2669	748	0	0	0	0	347	339
Sabal Energy Operating LLC - Permian Basin	1013699	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	5067	1030	0	0	0	0	566	1268
Tap Rock Operating	1013714	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Steward Energy II 430 Permian Basin	1013735	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
APR - Basin 430 - Production	1013736	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Luxe 430 Permian Basin	1013742	2019 Onshore petroleum and natural gas production (98.230(a)(2))	430 430 - Permian Basin	25	117	11	14	0	0	26	0
Williams G&B Facility 46° Permian Basin 430	1013748	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	0	7	0	0	0	0	0
DCP Midstream Gathering & Boosting-AAPG Province 430	1012204	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	167	8074	319	0	3	0	0
Permian Basin Gathering & Boosting-AAPG Province 430	1012213	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
ConocoPhillips Permian Basin 430 Gathering and Boosting	1012230	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	326	165	71	1	0	0	0
Chevron MCA 430 Permian Basin Gathering and Boosting	1012265	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	206	351	288	8	8	0	0
Pioneer Natural Resources USA Inc. Permian	1012321	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	0	0	700	0	39	0	0
430 Permian Basin GB DEC	1012353	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	0	0	0	0	0	0	0
Laredo Basin 430 BAG	1012359	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	134	163	18	204	0	0	0
WPX Energy Permian LLC Boosting and Gathering	1012365	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	25	0	0	0	0	19	0
Energy Transfer 430 - Permian Basin	1012390	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	32	1122	203	3	7	0	0
Durango Midstream - Permian Basin Gathering & Boosting	1012432	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	101	50	29	0	9	0	0
Davis Gas Processing Inc. 430 Permian Basin GB	1012445	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	9	47	11	0	3	0	0
WTF Jameson LP - 430 Permian Basin GB	1012446	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	86	73	14	0	0	0	0
WTF Gas Processing LLC - 430 Permian Basin GB	1012457	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	12	126	34	0	10	0	0
WTF South Permian Midstream LLC 430 Permian Basin GB	1012461	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	40	193	47	0	22	0	0
Enterprise Products Operating LLC 430 Permian Basin	1012492	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	215	605	60	33	13	0	0
Targo Resources Corp. 430 Permian Basin GB	1012500	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	80	11126	224	54	49	0	0
Lucid Energy Delaware 430 Permian Basin GB	1012529	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	0	0	86	0	0	0	0
XTO Energy Inc 430 Permian 84° GB	1012541	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	381	1298	152	2	7	0	0
OXY USA Inc. Permian Basin G&B - 430	1012551	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430 430 - Permian Basin	0	1622	1200	157	26	0	0	0
Kinder Morgan Production 430 Permian Basin GB	1012558	2019 Onshore petroleum and natural gas gathering and boosting (98.230(a)(9))	430								



Characterization of Methane Emissions from Gathering Compressor Stations: Final Report

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EXECUTIVE SUMMARY

This document is the final report to the U.S. Department of Energy (DOE) for contract DE-FE0029068 awarded to Colorado State University (CSU). CSU and subcontractor AECOM partnered with nine U.S. midstream operators to characterize emissions from natural gas gathering and boosting stations (“gathering stations”) – a sector of the natural gas supply chain where few measurements have been made and little data are available for component emissions. Although there is overlap in the classes of equipment on gathering stations with those on production sites or transmission stations that have been measured recently, emissions are likely to differ for functional and operational reasons.

Partner companies provided the study team site access to (1) measure methane emissions and (2) collect activity data on equipment and operations. Field measurements were made at 180 facilities in 11 U.S. states during June-November 2017. Measured facilities were sampled from 1705 partner facilities located in 28 American Association of Petroleum Geologists (AAPG) basins. Measurements were made in basins representative of current U.S. production and facilities selected for measurement shared key characteristics in proportion to all partner facilities.

The principal deliverable of this study is a set of emission factors for components and major equipment at gathering stations. Leaker and population emission factors were developed for components, and population factors were developed for major equipment. All data was also incorporated into a model to produce a nationally representative estimate of emissions from gathering stations. Emission factors and model results are intended to inform the U.S. Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI). Components were counted on 1002 major equipment units (compressors, dehydrators, separators, tanks, acid gas removal units, and yard piping). Emission measurements were made on 1938 major equipment units. Data from a parallel study performed by GSI Environmental Inc. under the same DOE funding program were also incorporated.

The field campaign supported a robust updating of emission factors for fugitive and vented



emissions on components and major equipment. In general, the study indicates that study emission factors either agree with, or are larger than, current greenhouse gas reporting program (GHGRP) emission factors for the western U.S. and most GHGI emission factors, and are substantially larger than emission factors used by the GHGRP for the eastern U.S.

This study also developed and field-tested two measurement methods to better characterize emissions from unburned methane entrained in compressor engine exhaust (“combustion slip”) and vented and fugitive methane emissions from gas-powered, pneumatically actuated valves and controllers. Emissions from these sources are not well characterized at compressor stations.

Long-term, direct measurements of pneumatic controller emissions were made on 72 pneumatic controllers (PCs) at 16 gathering stations; measurements averaged 76 hours in duration. New emission factors could not be developed due to measurement errors with the meters utilized for the study (see Section 4.3), and as a consequence, GHGRP emission factors were utilized to estimate pneumatic controller emissions in station and national estimates. However, the PC emissions data is still useful for a qualitative examination of pneumatic controller emissions [1]. In particular, these long-duration measurements provide insight into PC emissions behaviors that are not reflected in manufacturer’s literature and have not been shown in prior studies. Recorded PC data shows a high degree of variability in operation over the course of hours or days – especially for intermittent vent PCs. Recordings also show an unexpectedly high occurrence of abnormal emission behavior – 25 of 40 intermittent vent controllers show abnormal behavior at some point during the recording, and 5 of 24 were emitting at higher than the low-bleed maximum of 6 scfh.

Combustion slip was measured on 102 individual compressor drivers at 51 gathering stations. Results from combustion slip measurements indicate emissions similar to emission factors from EPA AP-42 [2].

Although component fugitive and vented emission factors are higher, current GHGI estimates are based upon whole-station measurements made in a prior field campaign [3] and subsequent national model [4]. Relative to these prior studies, and by extension the GHGI, emissions at stations



measured during the field campaign are statistically lower. The current study drew a nationally-representative sample from a larger population of stations than the previous study (1705 stations versus ≈ 700 stations) while working with a larger group of industry partners (9 partners versus 4 partners), which raises confidence in the current study. While reasons cannot be definitively stated, likely causes of the lower methane emissions in this study are: (1) the previous study measured facilities with substantially higher throughput than the current study (39.5 [0.223 to 382] versus 19.7 [0.068 to 116] MMscfd whole gas); (2) the partner population in the previous study indicated a larger proportion of more complex stations – this study sampled 60% compression-only stations versus 30% in the previous study [3]; (3) the two studies utilized different measurement methods; and, (4) there may have been operational improvements to gathering stations during the intervening four years.

To complete national estimates, the study utilized 319 per-basin GHGRP reports for gathering systems in 36 AAPG basins, including 15,895 reported compressors, and counts for other equipment, including gas pneumatic controllers, dehydrators, flares and other equipment. Using GHGRP activity data and data collected in the field campaign, the study estimated 6,108 [5,846 to 6,374] stations nationally, which is statistically higher than the current GHGI estimate of 5,241 stations. However, the study's national model indicated emissions that are statistically lower than current GHGI estimates for the gathering & boosting sector – 1,484 [1,439 to 1,537] $Gg \cdot y^{-1}CH_4$ versus a GHGI estimate of 1,955.1 $Gg \cdot y^{-1}CH_4$. Reasons for this difference align with those for station emission estimates - updated mix, size and throughput of stations, more complete activity data for stations, better estimates for unmeasured emission sources, including unit and station blowdowns, and possibly improvements in operations at gathering stations since prior studies.

Results presented in this report are supported by several supplemental volumes which are cited throughout. Supplemental volumes are further supported by appendices, as cited within. In addition, results will be disseminated in three peer-reviewed publications currently in preparation.

1. Zimmerle et al.[5] – Emission factors, activity data, and national estimate of emissions from



gathering stations.

2. Luck et al. [1] – Long duration pneumatic controller measurements.
3. Vaughn et al. [6] – Methane emissions from combustion slip; measurement methods and results.



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STANDARD TERMINOLOGY

AAPG	American Association of Petroleum Geologists
AGRU	acid gas removal unit
BHFS	Bacharach [®] HI FLOW [®] Sampler
CSU	Colorado State University
DOE	Department of Energy
EPA	Environmental Protection Agency
ESD	emergency shut-down
FTIR	Fourier Transform Infrared
GHGI	greenhouse gas inventory
GHGRP	greenhouse gas reporting program
GRI	Gas Research Institute
METEC	Methane Emissions Technology Evaluation Center
mtCO₂eq	metric tons CO ₂ equivalent
OGI	optical gas imaging
T&S	transmission and storage



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1 INTRODUCTION

1.1 Project Initiation

In 2016, the U.S. Department of Energy (DOE) Office of Fossil Energy issued a funding opportunity announcement (FOA) titled “Methane Emissions Mitigation and Quantification from Natural gas Infrastructure” driven by the President’s 2014 Climate Action Plan, which included a strategy to reduce methane emissions [7, 8]. The FOA funded research for developing leak mitigation-focused technologies and improving estimates of methane emissions from midstream natural gas operations, with a focus on better characterization of regional variations in emissions. Colorado State University (CSU) was awarded funding under Area of Interest 2A to perform direct emission measurements at the device level to develop methane emission factors for all classes of equipment found on *gathering and boosting* stations (referred to as “gathering stations” in this work). To accomplish this, CSU partnered with the engineering firm AECOM to assist with planning, logistics, field work and analysis.

Nine midstream natural gas companies also acted as partners in the study, and are listed in the acknowledgment section of this report. Partners provided data about their operations and offered access to their sites and input on the methods used in the study. The selection of facilities for the study from all partner facilities is described in Section 3.1.

The study had two primary objectives:

- Collect data on equipment counts and types (activity data) of gathering stations.
- Perform component level leak measurements suitable for developing new emission factors.

Both of the above deliverables were focused on updating the U.S. Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI), although the data may be of use longer term for other studies and updates to the EPA greenhouse gas reporting program (GHGRP).

In addition, the study also focused on two emission sources that are currently not well characterized for compressor stations:



- Unburned methane entrained in compressor engine exhaust (“combustion slip”)
- Methane emissions from natural gas-powered pneumatic valve controllers (“pneumatic controllers” or “PCs”).

1.2 Organization of This Report

This document is supported by three supplemental volumes which focus on:

S1 Pneumatics measurements

S2 Exhaust measurements

S3 Component, station and national emissions

References to supplemental volumes are made throughout this report in the form *SI S1-2.1*, which refers to supplemental volume 1 (Pneumatic measurements), chapter 2, section 1. Supplements also reference appendices, which provide detailed information on individual measurements or emission factors. Data in tabular files are referenced in the supplemental volumes by workbook sheet and/or file name. Additional protocol documents are attached for field and equipment measurement protocols. These are referenced, as appropriate, in the supplemental volumes.

This document is organized into three chapters:

- Overview and Background: provides an overview of gathering and boosting operations.
- Methods: describes measurement and analysis methods for fugitive and vented emissions, for long-duration pneumatic controller measurements, and for combustion slip measurements.
- Results: summarizes study findings for each measurement type.



2 OVERVIEW AND BACKGROUND

2.1 Gathering & Boosting Sector

The gathering and boosting (“gathering”) sector of the U.S. natural gas industry is a midstream sector between production and processing or transmission sectors. The U.S. gathering sector includes several thousand gathering compressor stations[9] which compress, and in some cases upgrade¹, natural gas. Gathering stations are interconnected by more than 400,000 miles of gathering pipeline[10]. This study focuses on methane emissions at gathering stations; no measurements or analysis of pipeline emissions were completed. While some gathering systems also transport liquids (oil, condensate, or water), this study measured and analyzed only the infrastructure handling natural gas.

Gathering stations are generally built around gas compression equipment which receives gas from production well pads and compresses it for delivery to gas processing plants. Alternatively, in basins where natural gas can be sufficiently upgraded at gathering stations, gas is delivered directly to transmission or distribution systems. Stations also include separators, tanks, piping, fuel gas systems, and miscellaneous other equipment to support gas upgrading, compression, and station operations. Stations also typically include equipment to support the pipelines connected to the facility: “pigging” launchers and receivers (for pipe cleaning operations), blocking valves for pipeline and station isolation, meters, and other similar equipment. Stations which upgrade gas utilize dehydrators to remove water from field gas, and, if needed, acid gas removal units (AGRUs) to remove acid gases such as H₂S or CO₂, and other contaminants. Examples of typical equipment are shown in Figure 1.

For measurement purposes, this study defines a *gathering station* as all equipment within the fence – or other clearly marked boundary – surrounding the facility. Figure 2 shows a typical example. For this study, a gathering station includes all equipment inside the boundary except for

¹Upgrading typically includes removing water (dehydration), and, in some locations, other impurities. It *does not* include separation of natural gas liquids or other hydrocarbon products, which is typically performed at natural gas processing plants.



Figure 1: Typical equipment found on gathering stations. Clockwise from top left: Compressor, separator, liquid storage tanks and dehydrator.

any co-located production wells, which are included in the production sector for emission purposes and were therefore excluded from measurement in this study.

2.2 Prior Work

The GHGI estimates greenhouse gas emissions from all sources in the U.S. For most sectors of the natural gas industry, the GHGI utilizes emission factors that have an activity basis of either major equipment counts or component counts. Emissions are calculated by multiplying emission factors by equipment or component counts. Recent studies have updated component and equipment emission factors for production [11, 12, 13], transmission and storage, [14], distribution [15], and other sectors. For each of these sectors, the GHGI typically develops activity data from annual reports of equipment counts to the GHGRP. Note that GHGRP data is reported only for facilities that exceed the reporting threshold for the sector, typically 25,000 metric tons CO₂ equivalent (mtCO₂eq) per facility; *facility* is defined by sector and could refer to all of a company's operations in a production basin.



Figure 2: Typical gathering station shown in satellite imagery. Like many compressor stations, the station is not surrounded by a fence, but its boundary is clearly defined by a gravel pad.

However, for the gathering sector, the GHGI currently estimates a national station count and uses a per-station emission factor to estimate emissions. The national station count is based upon an analysis of air permit data performed by Marchese et al. [4], scaled by changes in natural gas production since the time of publication (2015). The per-station emission factor is based upon a field campaign conducted in 2013-14 [3], which measured approximately 115 gathering stations, and a national model developed in Marchese et al.

Beginning with reporting year 2016, the GHGRP required midstream operators to report activity data and emissions by American Association of Petroleum Geologists (AAPG) basin when emissions from their gathering operations are greater than 25,000 mtCO₂eq in that basin. These data allow gathering sector emission estimates to be made at the major equipment or component-level instead of the station level, which could support updates to activity data year-over-year, and also enable a corresponding annual update of emissions estimates.

However, very few measurements have been made and little data are available on component-level emissions from equipment on gathering stations. The GHGRP uses component-level emission factors based on the results of a 1996 EPA/Gas Research Institute (GRI) [16] study that made



measurements exclusively on well pads and gas production sites. Although there is overlap in the classes of equipment present on production and gathering stations, emissions are likely to differ for functional and operational reasons. Likewise, comparable equipment is utilized in the transmission and storage (T&S) sector, but T&S equipment-level emission factors are unlikely to be representative of gathering operations, due to the larger size of T&S equipment and differences in gas composition. This study directly addresses these deficiencies in emission factors.

The study also performed specialized measurements on two emission sources of interest: combustion slip and pneumatic controllers.

Combustion slip: The vast majority of compressors operating in the gathering sector (96% of compressors in the field campaign) are driven by natural gas powered engines. The remainder are powered by electric motors or turbines. A typical compressor skid is shown in Fig. 3. Engines are often tested for criteria pollutants, but are not typically tested for methane emissions. Methane emission factors for engines are published in the EPA Compilation of Air Emission Factors (AP-42)[2], stratified by the three common engine types used in the industry: four-stroke lean-burn, four-stroke rich-burn, and two-stroke lean-burn.

Results from recent studies [17, 18, 14] indicate that combustion slip can represent a significant fraction of emissions from facilities with operating engines. The gathering sector operates a large number and variety of engines, which may have different emission rates. While a fraction of these engines are routinely tested for permitted air pollutants, the full diversity of gathering engines has not previously been measured for methane emissions. This drove the interest in measuring a wide sample of engines and updating combustion slip factors for this sector. A novel in-stack tracer measurement method was developed for this study to quantify methane emissions more quickly than standard stack testing protocols. The method was used on a representative selection of engines, across operators and operating regions.

Pneumatic controllers: Automated, pneumatically-powered valves and actuators are used to control process variables (temperature, level, pressure and flow) on stations in all sectors of the



Figure 3: Typical skid-mounted compressor driven by a reciprocating natural gas engine in the gathering and boosting sector.

natural gas supply chain. Many of these control systems use natural gas to power actuators, as stations have a constant source of high pressure natural gas which eliminates the need for separate compression equipment to compress and dry ambient air. This is especially advantageous for remote stations without connections to electrical power, where additional natural gas engines would be needed to drive electric generators or air compressors. Figure 4 shows an example of a PC installation, including actuator and controlled valve.

By design, the majority of these pneumatic controllers (PCs) vent a portion of their supply gas to the atmosphere while pressurizing or de-pressurizing valve actuators. These emissions occur either continuously between control events (“continuous bleed”) or in intermittent bursts (“intermittent bleed”), depending on the design and specific application of the PC. The EPA classifies PCs according to their normally operating vent behavior as intermittent or continuous bleed [19]. Continuous bleed devices are further classified as low-bleed or high-bleed based on their steady state (inactive) emissions [20]; PCs that vent <6 scfh of gas are classified as low-bleed and those that vent ≥ 6 scfh of gas are classified as high-bleed. In addition to emissions from venting during

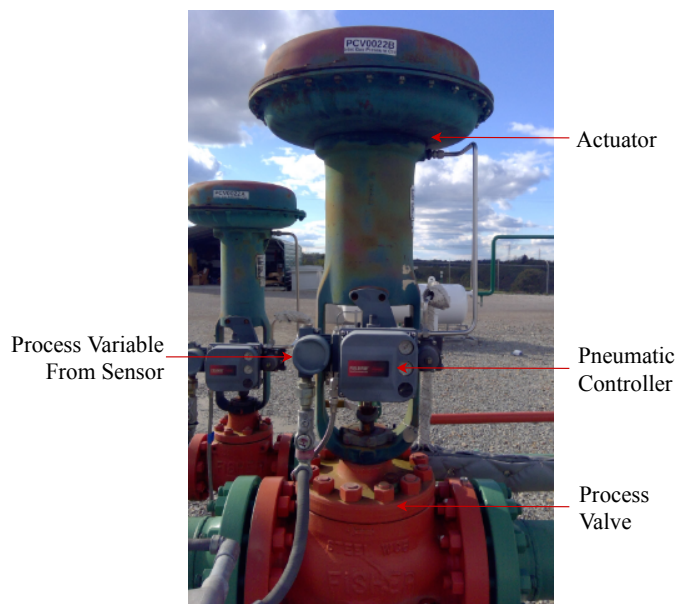


Figure 4: Example assembly of a PC, actuator and valve in pressure control service on a natural gas gathering station.

normal process control operation, some fraction of PCs may also emit gas through leaking tube fittings, valve stems, and damaged or malfunctioning controller components [1, 12, 15].

PC emission factors for the GHGRP are derived from the 1996 EPA/GRI study[16, 21], and a Canadian Petroleum Association emission rate study [22]. A relatively small data set was used to calculate these emission factors (41 continuous bleed controllers and 19 intermittent vent controllers). This single set of PC emission factors is used to estimate PC emissions from all sectors of onshore natural gas production.

These prior studies, along with more recent measurements [12, 11, 23, 24, 25], utilized short-duration measurements of PCs in order to sample as many PCs as possible during the study. Short-duration measurements have a limited ability to capture normal actuation behavior or abnormally operating behaviors, which may exhibit complex emission patterns in time. To address knowledge gaps in previous studies and improve the characterization of PC emissions behavior, the measurement strategy in this study was focused on collecting continuous, long duration (3-4



day) direct measurements of PC emissions from a representative sample of devices. This approach limited the total number of PCs that could be measured, but improved the understanding of PC behavior.



3 METHODS

3.1 Sampling Plan

To develop robust emission factors for gathering stations, the study secured site access and performed measurements on a sample of stations representative of the U.S. gathering sector in terms of size, geographic distribution, gas composition, and equipment mix. Nine midstream natural gas companies acted as industry partners in this project and provided activity data for their gathering station assets (including station locations, station type, mix of engines, and gas composition) and access to their gathering stations during the study. A brief overview of the sampling strategy is provided here with more detail discussed in SI S3-1. Additional sampling details are discussed for pneumatic devices in SI S1-2 and for exhaust measurements in SI S2-1.

Prior to the field campaign, the nine partner companies provided a facility list for their gathering assets. These companies operate approximately 1705 gathering stations, with assets in 28 AAPG basins. These basins account for 85% of annual natural gas production in the U.S. Combined, the partner companies operate 35% of all compressor units reported to the GHGRP from the gathering sector in 2016.

A sample of stations was selected from the population of partner stations using a randomized clustered sampling strategy. To ensure anonymity for industry partners, only basins where at least two partner companies had operating assets were considered for the field campaign. Basins were selected from this population, ensuring that the selection was representative of national basin diversity in terms of gas composition (wet/dry) and age of production plays. Each basin from this final population was assigned one week of the field campaign. While most weeks were dedicated to measurements at stations from a single partner company, several weeks included measurements from more than one company [SI S3-1.1].

Five primary stations (one dedicated to each day of the week) were randomly selected from partner assets in each sampled basins. For each primary station, up to five nearest geographic

neighbor stations were located and identified as secondary stations. While in the field, study teams first performed measurements and collected activity data each day at the assigned primary station. If time permitted, they then moved on to secondary stations in a pre-determined order. This method was executed over 19 field weeks, with measurements made at 180 gathering stations. The stratification by number of compressors (as a surrogate for station size) and station equipment mix of this final list of selected sites agreed with the stratification of all partner sites to within $\pm 12\%$ [SI Fig S3-2]. Figure 5 shows an example of a weekly campaign plan.

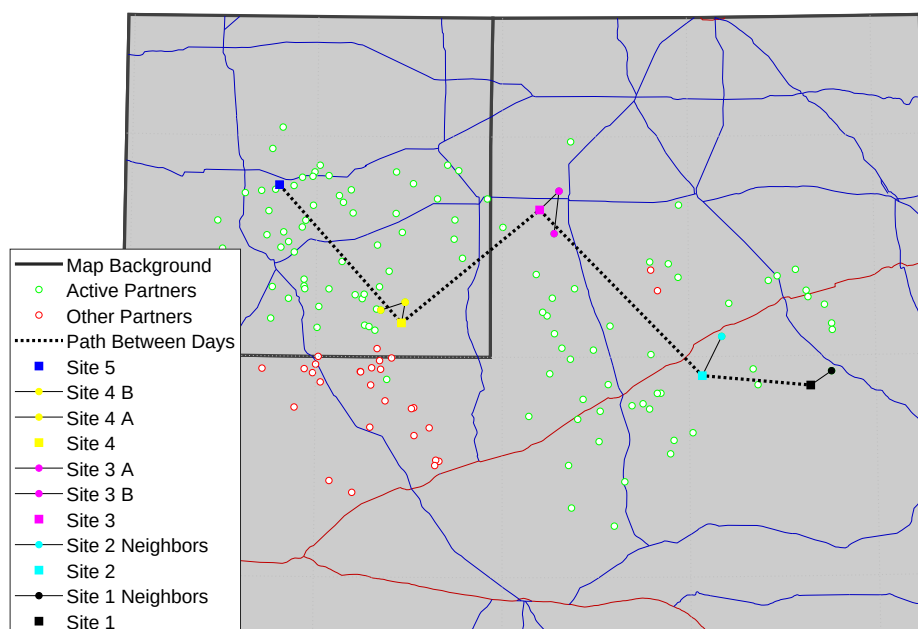


Figure 5: Example of a weekly campaign plan. Five stations were randomly selected from one partner's stations for the week. Stations were sorted in geographical order and assigned to a day, labeled *Site 1* to *Site 5*. Secondary stations were identified near each primary station. The number of secondary stations identified each day was adjusted for the size and complexity of the selected stations. For each measurement day, the primary station was measured first, followed by secondary (neighboring) stations, in a predetermined order, as time permitted.

Figure 6 shows the location of all field measurement locations, overlaid on county gas produc-

tion data for 2017. Sampling occurred in counties across a wide range of gas production intensities, including counties with the highest gas production in the U.S. (Northeastern Pennsylvania). Locations also represent a wide range of station ages and configurations.

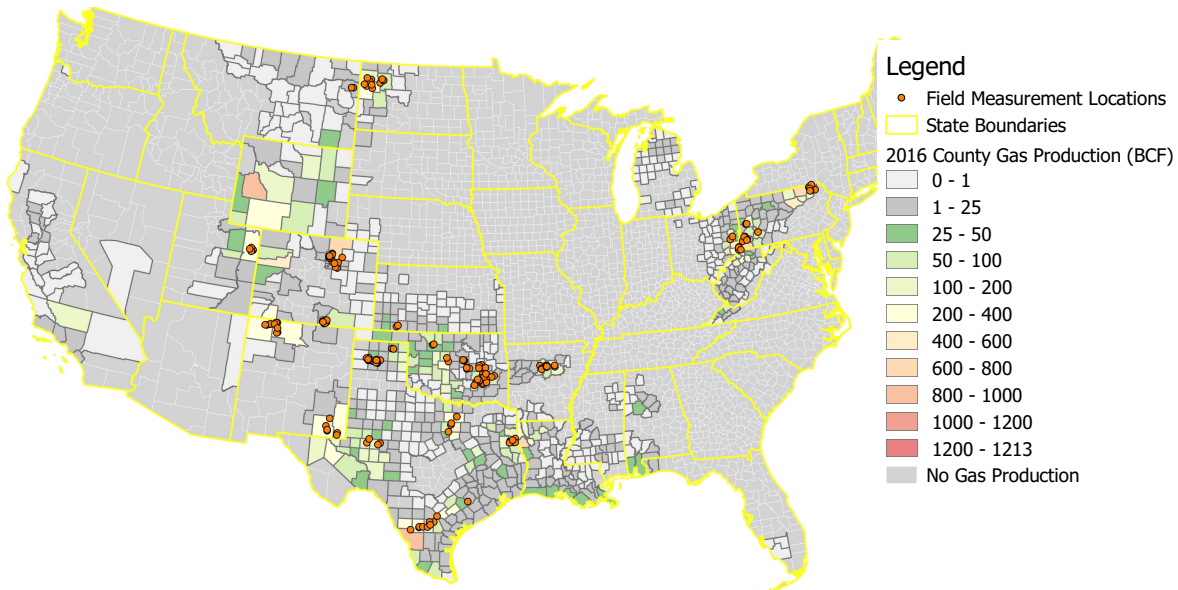


Figure 6: Location of all stations included in the field study. Gas production by county is taken from Drilling Info™ data. Points include stations measured by both field measurement teams.

Two teams of CSU and AECOM personnel were deployed during the field campaign (referred to a “Team 1” and “Team 2”). Each team was equipped with an optical gas imaging (OGI) camera, a Bacharach® HI FLOW® Sampler (BHFS) and anti-static measurement bags (often called “calibrated bags”) for identifying and measuring fugitive or vented emissions. [SI S3-1.3] Team 1 was additionally equipped with thermal mass flow meters for performing multi-day emissions measurements from PCs and a Fourier Transform Infrared (FTIR) spectrometer for measuring combustion slip. Figure 7 shows the location of pneumatic controller and exhaust measurement locations.

Long-duration PC measurements were only performed on stations with gas-powered pneumatics. Since 27% of partner facilities use air-powered pneumatics (commonly called “instrument air”),

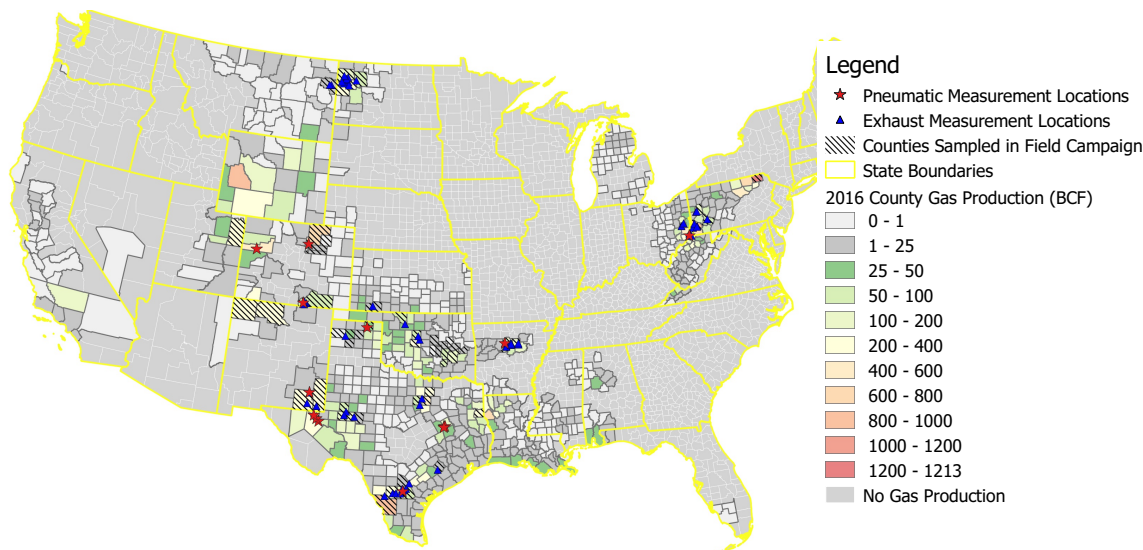


Figure 7: Location of all stations where long-duration pneumatic and combustion slip measurements were performed. All counties included in the field study are shaded. Due to a higher-than-expected prevalence of instrument air on study stations, not all stations included in the measurement campaign could be used for pneumatic measurements. Gas production by county is taken from Drilling Info™ data. All measurements were performed by “Team 1”.

some weeks did not support pneumatic measurements.

3.1.1 Measuring Fugitive and Vented Emissions

For the purpose of developing major equipment and component level emission factors, units of major equipment were defined by the isolation valves upstream and downstream of the piece of equipment. Major equipment categories are:

- *Compressors*: Compressor skid or unit, includes a compressor driver (engine, turbine, motor) and the gas compressor.
- *Dehydrators*
- *Acid gas removal units (AGRU)*
- *Station separators*: Large separators not on other major equipment units. For example,



interstage knock-out tanks on compressors were considered part of the compressor, while inlet separators on the suction header of stations were counted as station separators.

- *Liquid storage tanks:* Storage tanks, not including tanks located on other major equipment units. All tanks were atmospheric pressure tanks; no pressurized tanks were measured in this field campaign.
- *Yard piping:* All other equipment on the station.

Screening and measurement of emissions were conducted by unit of major equipment. Not all major equipment units were screened for leaks on every station visited. Emission measurements were performed on as many units as time allowed. Equipment was only classified as measured if the entire unit was screened and all emissions found were recorded and attempted to be measured. Similarly, components were only counted on a subset of the major equipment units on each station [SI S3-1.4].

3.1.2 Combustion Slip Measurements

Only one of the two field teams deployed during the field campaign (Team 1) was equipped to perform compressor exhaust measurements. Therefore, all stations allocated to field Team 1 at the start of the field campaign were considered for measurement. Tests were performed at least at the primary station selected for each day. Additional engines were tested at secondary stations if time allowed. At a small set of stations, combustion slip measurements were performed in tandem with regularly scheduled compliance testing, and compared to validate this study's novel measurement method. In cases where combustion slip measurements were made concurrently with compliance tests, operating conditions required for compliance testing were used. In all other cases engines were measured "as found." Therefore, sampled engines provided combustion slip data across a wide range of operating conditions and loads typical of partner gathering operations.

Not all engines could be measured. Exceptions include:

- Access or safety issues
- Exhaust stack configuration did not provide an adequate tracer injection location [SI S2-2.2]
- Insufficient time to complete a test

3.1.3 Pneumatic Controller Measurements

Long-duration PC measurements were scheduled for the 11 field-weeks allocated to Team 1 during the field campaign. Each week, the first station assigned for measurement on Monday was utilized for long-duration measurements. Instrumentation was installed on Monday, left to collect data for 3-4 days – typically until battery power was exhausted – and retrieved by the study team on Friday. However, during detailed campaign planning (after sample weeks had been allocated), the study team discovered that the pneumatic controllers at 27% of partner sites were operated on compressed air (often called “instrument air”). From an emissions perspective, this is a positive development, as it eliminates vented and fugitive emissions from PCs entirely. Consequently, long-duration measurements could only be made during 8 of 11 field-weeks. To distinguish measurements made during the field campaign from measurements made after the field campaign, PCs measured by Team 1 while on the field campaign are classified as “Class I” in the data summaries.

Due to the prevalence of stations using instrument air for PCs, PC measurements were continued after the conclusion of the field campaign to increase the sample size and diversity. Partners were requested to provide basin locations for sampling. The extended sampling included 11 additional gathering stations in four basins. These stations were selected in collaboration with industry partners in areas not visited during the field campaign and *were not* randomly selected during the original site selection. Otherwise, the same protocol was utilized for the measurements.

During the post-campaign phase, CSU personnel traveled to the stations which had been selected for sampling. At the first station, CSU personnel were present for the meter installation and trained a designated partner technician on how to install and de-install the measurement equipment, charge batteries, and upload data; these stations are designated as “Class II” in the data tables. CSU



personnel also traveled with the technician to all other stations which would be measured and finalized the selection of PCs to be measured; these stations are designated as “Class III” in the data tables. At the end of the measurement period on each station, the technician photographed the meter installation, uploaded data, recharged meters, and moved meters to the next designated location. Including all measurements, PC measurements were made at stations owned by eight of the nine partner companies participating in the study; all stations operated by the last partner utilized compressed air to operate pneumatic devices and therefore were not measured.

Measured PCs were selected on an opportunistic basis, subject to several constraints. First, to install the meter it was necessary to disconnect the supply gas lines temporarily. This was not an issue for on/off type controllers but posed issues when PCs needed to continuously throttle or maintain sensitive control parameters continuously. For sensitive controllers, some station equipment was taken off-line for meter installation, if possible. If not possible, an attempt was made to install the meter on the exhaust port of the PC. If neither method worked, the PC was not measured, and a different PC was selected.

Second, the focus of this study was on measuring PCs that control process variables. Therefore, emergency shut-down (ESD) and other station safety or isolation controllers – which rarely actuate – were not instrumented in this study.

Overall, the study team used engineering judgment to select controllers for measurement considering both the practicality of measurement, and the best method to measure a diverse population of PCs.

3.1.4 Additional Measurement Data

In addition to data collected during the field campaign, data from a contemporaneous study conducted by GSI Environmental Inc. was incorporated into the study data. The GSI study measured fugitive and vented emissions at four compressor stations multiple times over the course of a year. Measurements were conducted similarly to Team 2 of the field campaign, and included component



measurement using similar methods to the field campaign, but no measurements of combustion slip and no long-duration measurements of PCs. (SI S3-1.2)

To avoid over-representing these stations in the resulting data, data from each emission location was averaged if that location had been measured multiple times. The impact of absorbing these data on resulting emission factors is presented in SI Tables S3-1 and S3-2.

3.2 Measurement Methods

Measurement methods are subdivided into three sub-sections, covering fugitive and vented emissions, combustion slip, and long-duration pneumatic controller measurements.

3.2.1 Fugitive and Vented Emissions

This study used methods well established in previous research [18, 11, 15] to identify and quantify fugitive and vented emissions at the component level. Emissions were identified using OGI cameras (either Opgal™ EyeCGas® or FLIR™ GF320®). Nearly all emission locations were measured using a BHFS [SI S3-1.3]. Locations that appeared to exceed the capacity of the BHFS were measured using an anti-static bag of known volume and recording the time it took for gas to fill the bag. [SI S3-1.3]

Lower detection limits of the OGI cameras were taken from previous experimental work by Ravikumar et al. [26] and specialized testing was completed to establish a lower detection limit for the BHFS. Both sets of tests were performed at the CSU Methane Emissions Technology Evaluation Center (METEC). [SI S3-1.3]

A total of 1262 successful measurements were made, 1258 using the BHFS, and 4 using anti-static bags. Data from the GSI study added another 174 measurements, made with similar techniques. After averaging, as discussed in Section 3.1.4, the GSI data resulted in the addition of 105 measurements to the study.

For this study, an exceptional effort was made to record and classify unsuccessful measurement



attempts. After the field campaign, each unsuccessful measurement attempt was assigned a quality indicator that was used to estimate emissions when developing emission factors; a total of 231 such attempts were logged and classified, using the eight classifications discussed in SI S3-1.5. Five of the eight classifications represent measurements that could not be completed for environmental (e.g. weather) or mechanical (e.g. an inaccessible leak location) reasons. Emissions for these classifications were estimated using data from successful measurements. One classification, *OGI Non-detect* indicated measurements used to test the efficacy of the OGI screening method, and required no additional processing.

The remaining two classifications require further discussion. First, *incomplete capture* indicates that all of the emissions could not be captured by the BHFS during the measurement attempt. These emissions were estimated using other successful measurements and an estimate of the fraction of emissions not captured [SI S3-2.5].

The remaining classification, *exceeded capacity* indicates emission locations where the source was too large to be measured using the BHFS or anti-static bags. These emissions were estimated by developing several specialized emission factors using data from other studies [SI S3-4.2, Table S3-38]. The emission factors for large emitters were not included in component leaker or population factors to avoid unduly skewing the results of closely-coupled component emission factors [SI S3-2.4]. Large emitter emissions have substantial impact on major equipment emission factors, adding 71% - 79% to the impacted major equipment factors [SI Table S3-39]. However, since the majority of emissions are not contributed by fugitive and vented sources, the impact of large emitters on national emissions is substantially smaller – 19% [14% to 24%].

3.2.2 Compressor Engine Exhaust

The in-stack tracer method developed for this study was derived from EPA method ALT-012, “An Alternate Procedure For Stack Gas Volumetric Flow Rate Determination” [27]. This method involves injecting a tracer gas (the method recommends sulfur hexafluoride, SF₆) at a known flow



rate into an exhaust system, and estimating the total stack flow based on the dilution of the tracer gas. This requires that the tracer gas is injected far enough upstream of the exhaust outlet to ensure the tracer gas and exhaust stream are well-mixed, and also requires a tracer gas does not dissociate at the exhaust temperature or react with the exhaust gases. The tracer gas concentration measured at the exhaust outlet can be used to estimate the total exhaust stack flow rate, and the flow rate of any other exhaust gas species measured at the stack outlet. Figure 8 shows typical locations for tracer injection and exhaust measurement.

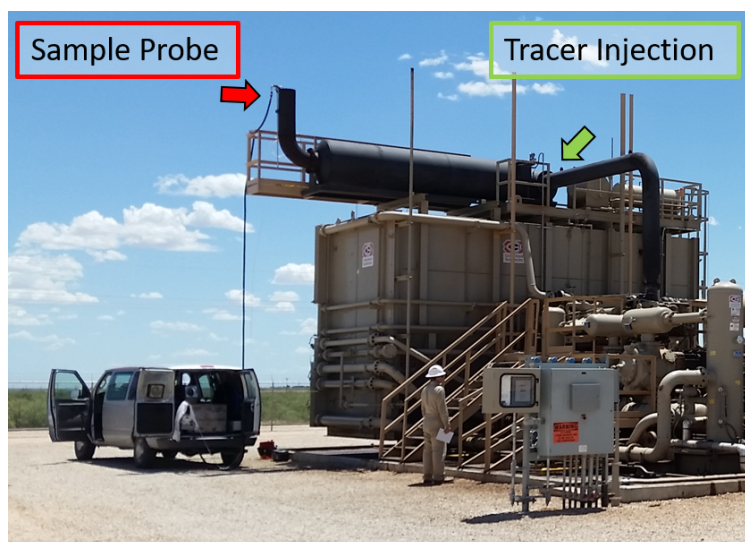


Figure 8: Example in-stack tracer measurement setup. Tracer gas is injected into the exhaust system upstream of the silencer. The tracer is mixed with exhaust gases in transit through the silencer and related piping. Well-mixed tracer and exhaust gases are collected at the sample probe and delivered through heated sample lines to an FTIR spectrometer in the van. The van also contains the tracer gas bottle and mass flow controller.

Due to the high temperature of rich burn engine exhaust, the study method utilized CF_4 (R14 Tetrafluoromethane 99.99%, Airgas Inc.) as a tracer gas, rather than SF_6 , which may break down at rich burn exhaust temperatures. During testing, CF_4 was injected into the exhaust system through an available port or directly into the exhaust using a calibrated mass flow controller (Alicat Scientific, MCM-5SLPM-D). Choice of the tracer injection location varied depending upon the stack configuration, available injection ports, and accessibility and condition of the ports. Engine exhaust



(including tracer) gas was collected near the exit of exhaust stacks using stainless steel probes and a heated sample line. Multi-port probes with holes at 16.7%, 50%, and 83.3% of the stack diameter were used in stacks with diameters ≥ 6 in. For smaller stacks (< 6 in), single-point sample probes were used. Speciation was performed using an MKS Multigas 2030 FTIR spectrometer.

To validate the method, testing was performed on seven engines while a third party stack testing company was also testing the engine using standard methods, as described in Section 4.2.1.

3.2.3 Pneumatic Controller Emissions

Six thermal dispersion mass flow meters, also known as “hot wire” meters, were used during the study to quantify emissions from PCs. The measurement system used was adapted from methods used in previous studies [25, 23]. Several modifications were made, including: independent power supplies with an average 76-hour battery life to facilitate continuous multi-day measurements on remote stations without power connections; integrated data logging capability; and more robust safety certifications (Class I/Div I), for unsupervised operation in areas where explosive gases were present during normal operation.

Emissions from PCs were measured by connecting the meters to PC vent ports or in-line with PC supply gas lines [SI S1-3.3]. Connections to supply gas lines were used whenever possible, as this configuration reliably measures all gas supplied to the control loop. Connections at vent ports were only used when connections to supply gas lines could not be made for safety or operational reasons (see Section 3.1.3). Connections at vent ports only capture emissions from a single point in the control loop and do not capture emissions from other potential leak points in the system. Schematics of each of these connections are shown in SI Figures S1-2 and S1-3.



Figure 9: Emission measurement system installed on supply gas line to PC controlling liquid level in a secondary liquids storage tank.

4 RESULTS AND DISCUSSION

4.1 Fugitive and Vented Emission Factors

The principal deliverable of this study is a set of emission factors for components and major equipment at gathering stations. Emission factors are summarized below and in Zimmerle et al. [5]. This study emphasized the development of complete emission factors – i.e. emission factors that account for all fugitive and vented emissions on major equipment units in the principal categories used at gathering stations - AGRUs, compressors, dehydrators, separators, tanks and yard piping. The GHGI will likely utilize GHGRP data, where activity data is primarily reported at the major equipment level, as the primary source of activity data for the GHGI estimates. Therefore, for GHGI purposes, or for other inventories utilizing the GHGRP activity data, it is likely better to utilize major equipment counts and emission factors for each type of major equipment.

In addition to major equipment factors in Section 4.1.3, Sections 4.1.1 and 4.1.2 discuss emission



factors at the component-level. A discussion of component emission factors provides a basis for comparison to prior studies that focused on component factors. In addition, component factors can be utilized to adjust major equipment factors as needed if major equipment configurations change substantially. Note that this study did not update pneumatic controller emission factors for gathering stations, for reasons described in Section 4.3.

Component emission factors are provided using a component classification similar to that used in the T&S sector [14]. Prior experience has shown that components on compressor skids tend to have different, typically larger, emission rates than components in service on other equipment at a compressor station [28, 18]. Therefore, two emission factors are provided for common components, divided into “compressor service” and “non-compressor service” classifications. For some component categories, additional work was performed to determine if emission factors should be subdivided or combined; see SI S3-2.1 to S3-2.3 for additional details.

Emission factors are provided for both whole gas and methane at standard conditions, in cubic feet per hour (scfh). Calculation of standard conditions is described in SI S3-1.6.

Finally, no emissions were detected for two component categories during the field campaign, shown in Table 1. Since it is unlikely that these components would have *no* emissions as a general rule, no emission factor is provided, and the emission factor for “other” components would be appropriate for estimating emissions from these components.

Table 1: Component Categories with No OGI Detections or Measurements

Component Category	Number of Components Counted
Gauge	1859
Meter	618



4.1.1 Leaker Emission Factors

Leaker emission factors represent emission rates expected from a component category *if* emissions are detected during a leak detection screen using an OGI camera or a similar screening method. In use, leaker factors are utilized when a station has been screened for leaks – emissions are calculated by multiplying the count of identified leaks by the appropriate leaker emission factor [SI S3-2].

Tables 2 and 3 summarize the leaker emission factors for whole gas and methane, respectively. Emission factors are grouped by the service categories. The *other* service category includes emission factors where there was insufficient data to develop separate factors for each service category. These factors may be utilized for any service type.

Leaker factors include estimates for emissions which could not be completely captured by the measurement methods, but do not include estimates for *large emitters*, which are only included in the major equipment factors. [SI S3-2.5] The number of simulated emission points in each emission factor is provided in the column *Number Simulated*. Finally, the last column of the table indicates the fraction of emissions caused by the largest 5% of emission locations. The column is blank if there were fewer than 20 measured leaks. This is a measure of the skew (also called “long tail”) of the emissions distribution. For most leaker factors, 50% or more of emissions are due to the largest 5% of emitters.



Table 2: Whole Gas Leaker Emission Factors

Component	Number Measured	Number Simulated	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Fraction of Emissions Due to Largest 5% of Emitters
Non-compressor service					
Connector Flanged	31	1	6.2	[+43%/-37%]	21%
Connector Threaded	82	0	4.73	[+36%/-30%]	30%
PRV	23	0	9.98	[+129%/-83%]	57%
Regulator	43	0	6.7	[+36%/-33%]	20%
Valve	99	0	7.06	[+41%/-34%]	41%
Compressor service					
Connector Flanged	41	1	8.77	[+55%/-40%]	33%
Connector Threaded	107	5	11.9	[+56%/-39%]	49%
PRV	35	1	18.5	[+84%/-60%]	45%
Regulator	37	0	11.8	[+40%/-34%]	22%
Valve	39	1	36.9	[+113%/-66%]	59%
Common Multi-Unit Vent	13	0	59.4	[+81%/-71%]	
Common Single-Unit Vent	23	0	61.7	[+46%/-42%]	20%
Blowdown Vent	30	1	16.1	[+148%/-71%]	60%
Pocket Vent	23	0	6.32	[+78%/-61%]	33%
Rod Packing Vent	390	7	26.5	[+35%/-25%]	52%
Starter Vent	21	0	287	[+184%/-96%]	88%
Tank service					
Common Multi-Unit Vent	15	0	120	[+91%/-70%]	
Common Single-Unit Vent	42	2	48.8	[+91%/-63%]	50%
Thief Hatch	65	0	29.9	[+64%/-48%]	47%
Other					
Common Station Vent	6	1	82.2	[+102%/-72%]	
OEL	23	0	3.94	[+71%/-52%]	32%
Other	42	1	21.7	[+74%/-54%]	50%
Pump	12	2	29.9	[+75%/-52%]	



Table 3: Methane Leaker Emission Factors

Component	Number Measured	Number Simulated	Emission Factor (scfh CH ₄)	Confidence Interval (scfh CH ₄)	Fraction of Emissions Due to Largest 5% of Emitters
Non-compressor service					
Connector Flanged	31	1	5.21	[+44%/-38%]	23%
Connector Threaded	82	0	4.08	[+38%/-31%]	31%
PRV	23	0	8.88	[+131%/-85%]	59%
Regulator	43	0	5.49	[+39%/-34%]	22%
Valve	99	0	5.99	[+41%/-35%]	41%
Compressor service					
Connector Flanged	41	1	6.73	[+53%/-40%]	31%
Connector Threaded	107	5	9.99	[+56%/-40%]	50%
PRV	35	1	15.9	[+91%/-62%]	47%
Regulator	37	0	9.42	[+36%/-32%]	19%
Valve	39	1	33.4	[+123%/-70%]	62%
Common Multi-Unit Vent	13	0	50.7	[+82%/-68%]	
Common Single-Unit Vent	23	0	49.6	[+47%/-40%]	20%
Blowdown Vent	30	1	11.7	[+148%/-72%]	60%
Pocket Vent	23	0	5.34	[+81%/-60%]	37%
Rod Packing Vent	390	7	23.4	[+35%/-26%]	54%
Starter Vent	21	0	283	[+187%/-98%]	89%
Tank service					
Common Multi-Unit Vent	15	0	112	[+100%/-74%]	
Common Single-Unit Vent	42	2	44.4	[+93%/-64%]	51%
Thief Hatch	65	0	26.3	[+66%/-51%]	50%
Other					
Common Station Vent	6	1	73.9	[+98%/-70%]	
OEL	23	0	3.22	[+68%/-52%]	32%
Other	42	1	18.9	[+83%/-56%]	53%
Pump	12	2	22.6	[+78%/-56%]	

4.1.2 Population Emission Factors

Population, or *average*, emission factors represent the distribution of emission rates common to a component type or category. In use, emissions are estimated by multiplying a count of all components of one type by the population factor for that component type. Development of population factors utilizes the same measured emissions data as leaker emission factors: measured emissions are divided by the number of components screened during the field campaign.

Two factors needed to be considered when developing population factors [SI S3-3]:

1. *Complete component counts*: During the field campaign, emissions were screened and measured on one sample of major equipment units, while components were counted on a different



sample of major equipment units. This allowed field teams to balance leak measurement and counting activities, and in the case of component counting, assure that a sufficient sample of each type of major equipment was counted. Therefore, screened and measured units were not necessarily counted, and vice versa. If a unit was screened and measured, but not counted, the total component count on that unit was estimated by using the component counts from other similar units. [SI S3-3.1]

2. *Detected but unmeasured emissions:* As noted earlier, some detected emissions could not be measured. For population emission factors, these emission sources were estimated by using the leaker emission factor for the component. The lone exception to this rule is for large emitters (measurement quality indicator *exceeded capacity*); these emitters were not included in component emission factors for reasons discussed in SI S3-4.2.

All leaker factors do not have a corresponding population factor, as will be evident by comparing Table 2 with Table 4. This occurs when the underlying component count was incomplete or was not performed during the field campaign, and could not be estimated from other information.

Component counts for each component, on each type of major equipment, are provided in SI S3-3.4, Tables S3-30 to S3-35. These tables also compare component counts to those developed in the EPA/GRI 1996 study [16]. Compared to that study, we find that component counts in this study tend to be substantially larger than those from the eastern U.S. and often smaller than those from the western U.S. This disagreement indicates that equipment surveyed in the EPA/GRI study, which focused on well pads and associated equipment, was substantially different from gathering station equipment utilized today.

Population factors are summarized in Table 4 for whole gas and Table 5 for methane. Service categories are the same as discussed for leaker emission factor (Section 4.1.1). *Activity basis* indicates the correct component count to use with each emission factor. For example, the blowdown vent emission factor assumes there is one blowdown vent stack for each compressor. Therefore, compressor count, rather than blowdown stack count, should be used as the activity basis for the



emission factor. The categories are:

- *Counted Components:* A count of components was performed, as described above, on a statistically significant sample of major equipment units.
- *One per Compressor:* Component was not counted; we assume there is one component on each compressor skid.
- *Compressor Cylinders:* Component was not counted; we assume that each pocket vent is separately vented.
- *One per Tank:* Most tanks have several vents or outlets that can potentially be open to atmosphere, making counting and classification difficult. Section S3-2.1 discusses the type of vents seen during the field campaign and how single- and multi-tank vents were classified and modeled.

Mean population for each emission factor indicates the number of components screened during the field campaign - i.e. the count of components which *could* have been leaking. For non-compressor service, component counts include all major equipment that is not a compressor skid, i.e. all components on AGRUs, dehydrators, separators, and yard piping. Tank counts were not included, see SI S3-1.4.



Table 4: Whole Gas Average Emission Factors

Component	Activity Basis	Mean Population	Emission Factor (scfh WholeGas)	Confidence Interval (scfh WholeGas)
Non-compressor service				
Connector Flanged	Counted Components	12,255	0.0168	[+15%/-12%]
Connector Threaded	Counted Components	38,685	0.0104	[+12%/-9.4%]
PRV	Counted Components	1,068	0.264	[+51%/-20%]
Regulator	Counted Components	607	0.524	[+22%/-18%]
Valve	Counted Components	9,964	0.0811	[+19%/-14%]
Compressor service				
Connector Flanged	Counted Components	30,942	0.0135	[+21%/-11%]
Connector Threaded	Counted Components	60,397	0.0249	[+30%/-20%]
PRV	Counted Components	1,698	0.474	[+45%/-24%]
Regulator	Counted Components	658	0.668	[+13%/-11%]
Valve	Counted Components	10,206	0.153	[+45%/-13%]
Common Single-Unit Vent	One per Compressor	435	4.07	[+19%/-14%]
Blowdown Vent	One per Compressor	435	1.36	[+77%/-37%]
Pocket Vent	Compressor Cylinders	1,506	0.109	[+27%/-14%]
Rod Packing Vent	One per Compressor	435	28.4	[+21%/-11%]
Tank service				
Common Single-Unit Vent	One per Tank	251	9.21	[+47%/-25%]
Thief Hatch	One per Tank	251	9.85	[+28%/-14%]
Other				
OEL	Counted Components	476	0.209	[+31%/-20%]

Table 5: Methane Average Emission Factors

Component	Activity Basis	Mean Population	Emission Factor (scfh CH ₄)	Confidence Interval (scfh CH ₄)
Non-compressor service				
Connector Flanged	Counted Components	12,255	0.014	[+15%/-12%]
Connector Threaded	Counted Components	38,685	0.00898	[+12%/-9.4%]
PRV	Counted Components	1,068	0.236	[+51%/-20%]
Regulator	Counted Components	607	0.427	[+23%/-18%]
Valve	Counted Components	9,964	0.0697	[+19%/-14%]
Compressor service				
Connector Flanged	Counted Components	30,942	0.0103	[+19%/-11%]
Connector Threaded	Counted Components	60,397	0.0211	[+31%/-19%]
PRV	Counted Components	1,698	0.409	[+48%/-26%]
Regulator	Counted Components	658	0.53	[+13%/-11%]
Valve	Counted Components	10,206	0.138	[+49%/-12%]
Common Single-Unit Vent	One per Compressor	435	3.24	[+19%/-14%]
Blowdown Vent	One per Compressor	435	1.02	[+77%/-37%]
Pocket Vent	Compressor Cylinders	1,506	0.0925	[+29%/-13%]
Rod Packing Vent	One per Compressor	435	25	[+21%/-11%]
Tank service				
Common Single-Unit Vent	One per Tank	251	8.52	[+44%/-25%]
Thief Hatch	One per Tank	251	8.77	[+30%/-16%]
Other				
OEL	Counted Components	476	0.172	[+31%/-19%]



4.1.3 Major Equipment Fugitive and Vented Emission Factors

Major equipment emission factors estimate the distribution of fugitive and vented emissions from major equipment units. The major equipment factors from this study include estimates for all emissions detected in the field campaign, including estimates for large emitters [SI S3-4.2], which are not included in component leaker or population factors. Construction of the factors is detailed in SI S3-4.1.

Categories selected for major equipment match component major equipment units reported to the GHGRP for the gathering and boosting sector. Using that structure, major equipment factors include all fugitive emissions, and selected vented emissions for sources which may have both fugitive and vented emissions. In general, the emissions represented by these factors are fugitive emissions (i.e. leaks), with the exception of two categories:

- *Rod packing vents:* Since most compressors were measured while pressurized and operating, emissions from rod packing vents are *vented*, i.e. expected, emissions, although the rod packing on some compressor cylinders may be venting more than manufacturer’s specifications.
- *Tank vents:* For uncontrolled tanks, tank vents are primarily used to vent flash gas from liquids in the tank. However, leaks in upstream equipment, such as dump valves on separators, may malfunction and leak gas that is eventually routed to, and emitted from, tank vents. For controlled tanks, all emissions should be routed to a flare or vapor recovery unit, and any measured emissions are fugitive, i.e. unintended.

To estimate all emissions, the major equipment emission factors must be augmented by several remaining emission sources:

- Combustion slip is tracked separately as per common inventory practice; it is not included in compressor emissions.
- Fugitive and vented emissions from pneumatic controllers; as per common practice for GHGI



and GHGRP, pneumatic controllers are not included as part of the major equipment where they are located.

- Dehydrator still vents
- AGRU vents
- Uncombusted methane in flare emissions
- Unit and station blowdown events. These emissions occur through the same vent locations as the fugitive emissions discussed earlier, but are classified as specific events, and the emissions are typically estimated using engineering calculations.

Emission factors are summarized in Table 6 for whole gas and Table 7 for methane. The activity basis of each emission factor is typically a unit of major equipment, i.e. one compressor or one dehydrator. Tank emissions are on a per-tank basis, not tank battery. There is one unit of yard piping per station, regardless of the station size. The wide confidence interval reflects the range of yard piping complexity, size and emissions behavior across the stations measured in the field campaign. The mean population for each emission factor is the number of units measured during the field campaign. The AGRU factor is statistically weak, with wide confidence intervals, due to the small number of units encountered in the campaign. [SI S3-4.3]

The number of emission sources is summarized in the last three columns of the table, including the mean and maximum number of sources on any one unit. A substantial number of units had no detected emission sources, from a low of 20% of compressors to over half of all AGRUs, dehydrators, and separators. Approximately half of all stations had no detected emissions on the station's yard piping.



Table 6: Major Equipment Whole Gas Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh whole gas)	Confidence Interval (scfh whole gas)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU ¹	Unit	8	3.26	[+255%/-98%]	0.5	63%	2
Compressor	Unit	436	105	[+89%/-46%]	2.68	20%	18
Dehydrator	Unit	124	2.97	[+83%/-62%]	0.532	74%	6
Separator	Unit	326	0.557	[+72%/-55%]	0.153	90%	6
Tank	Tank	252	38.6	[+139%/-63%]	0.79	44%	4
YardPiping	Station	149	50.4	[+277%/-77%]	1.79	51%	17

¹ Emission factor is based upon few measurements and is unlikely to be robust.

Table 7: Major Equipment Methane Emission Factors

Category	Activity Basis	Mean Population	Emission Factor (scfh CH ₄)	Confidence Interval (scfh CH ₄)	Mean Sources per Unit	Fraction of Units with No Sources	Maximum Sources per Unit
AGRU ¹	Unit	8	3.26	[+257%/-98%]	0.5	63%	2
Compressor	Unit	436	105	[+85%/-47%]	2.68	20%	18
Dehydrator	Unit	124	2.97	[+78%/-60%]	0.532	74%	6
Separator	Unit	326	0.557	[+73%/-56%]	0.153	90%	6
Tank	Tank	252	38.6	[+134%/-62%]	0.79	44%	4
YardPiping	Station	149	50.4	[+308%/-77%]	1.79	51%	17

¹ Emission factor is based upon few measurements and is unlikely to be robust.

4.2 Combustion Slip: Methane in Compressor Engine Exhaust

This section briefly discusses combustion slip measurements. Additional detail is provided in SI Volume 2, and in Vaughn et al. [6].

4.2.1 Method Validation

Several gathering station visits were arranged to coincide with third-party engine compliance testing. At these stations, the CSU study team performed exhaust measurements concurrently with stack testing contractors. As a result, direct comparisons between stack flows predicted by the in-stack tracer method could be made to EPA Method 2 predictions on seven units.

Exhaust stack flow estimates from the in-stack tracer method were compared to EPA Method 2 stack flow estimates using the Bland-Altman difference method and variance weighted, least-squares regression. Total stack flows estimated by the two methods were found to agree when compared by these methods. The results of in-stack tracer measurements on 42 engines were also compared



with the expected stack flows from manufacturer data sheets and manufacturer-provided software programs as an additional evaluation of the accuracy of the in-stack test method. This check could only be performed against newer engines equipped digital or analog readouts that allowed the study team to collect operating data on the engine (such as load percent, engine RPM and exhaust manifold pressure). In general, the total stack flows for both 4SLB and 4SRB engines agree with manufacturer specifications [SI S2-4]. The accuracy of the FTIR used to measure exhaust gas species composition was also periodically checked against known standards over the course of the field campaign [SI S2-2.3].

4.2.2 Comparison to EPA Emission Factors

Combustion slip measurements were made on 116 engines (70 4SLB and 46 4SRB) during the field campaign. An example of time series emission and activity data collected for each tested unit can be found in SI figures S2-4 to S2-6. The data reduction methodology outlined in SI S2-2.2 was applied to each set of stack test data to quantify measurement error and calculate in-stack tracer flow and combustion slip emission rates. The resulting combustion slip emission rates were aggregated according to their AP-42 classification (only 4SLB and 4SRB engines were measured during this study) and compared to the following corresponding methane emission factors:

- US EPA compilation of air pollutant emission factors for reciprocating natural gas engines (AP-42) [2]
- US EPA GHGI estimates [31]
- US EPA GHGRP estimates [32]

Study factors were compared in two ways. First, measured combustion slip emission rates were compared directly, without consideration of activity data. Second, published emission factors were applied to the population of engines measured in this study. The resulting combustion slip emission rate estimates were compared to those measured directly in this study. This approach was used



because the combustion slip emission factors used in the GHGI appear to be based on the emission factors from the GRI/EPA 1996 report [33], which include activity weighting applicable to the population of compressor engines in use at the time of publication. The distinction between “measured emission factors” and “activity-weighted” emission factors is important to note when attempting to use these factors to estimate emissions. The underlying mix of equipment, and utilization rates, may change with time, which in turn may decrease the future accuracy (or even applicability) of activity-weighted emission factors. Additionally, while activity weighted emission factors may properly account for emissions in aggregate (national, an entire industry), they may have limited value for gaining insight into emissions at finer scales (regional, sub-sector, facility).

4.3 Pneumatic Controllers

Long-duration measurements were successfully made on 72 PCs (40 intermittent vent, 24 low bleed and 8 high bleed PCs) at 15 natural gas gathering compressor stations between June 2017 and May 2018. The average measurement duration of these recordings was 76 hours. To anonymize each data set, stations visited were assigned a randomly generated letter and each PC measured on that site was given a number 1-6 corresponding to the number of the flow meter that was connected to that device. All measured devices were then identified using this naming scheme. The gas temperature, pressure and flow rates recorded for PC D-1 (measurement made on site 'D' using meter #1) are shown in Figure 10.

Comprehensive metadata were collected for each PC measured at each station. Metadata collected included PC make/model, process variable controlled, operational mode of controlled valve (throttling or snap acting), associated major equipment, and EPA classification. Metadata for device D-1 is shown in Table 8.

Time series plots of emissions rates and metadata for all PCs measured during this study are included in SI S1-7. The proportional band settings (for PCs fitted with this feature) and the supply gas pressures when meters were attached to vent ports *were not* recorded in the field.

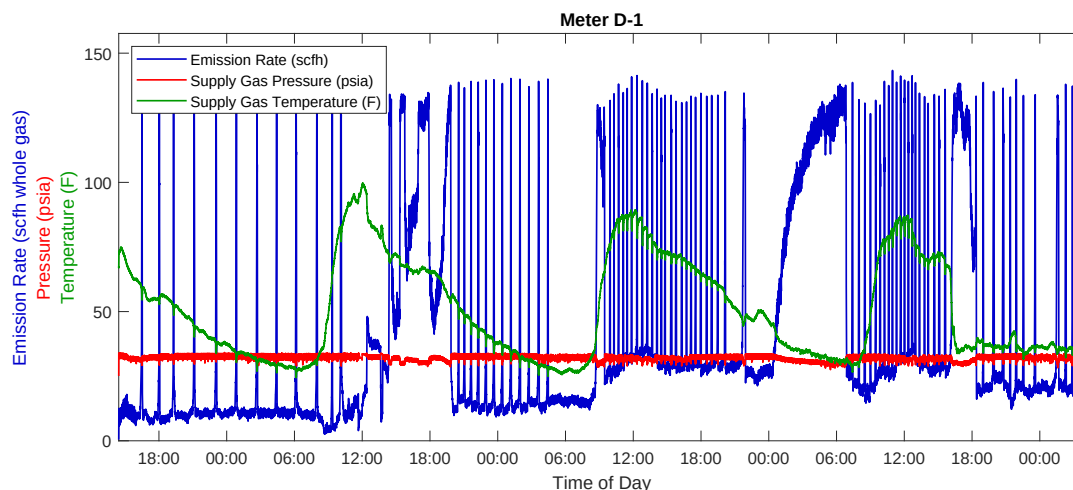


Figure 10: Example of flow meter recordings of PC emissions, supply gas temperature and supply gas pressure for Site D, meter 1, recorded over an 85-hour period. D-1 is an intermittent vent PC that exhibits multiple abnormal behaviors. For a substantial fraction of the recording period, emissions do not return to zero between actuations – one type of abnormal behavior. In addition, while D-1 actuates quickly during some recorded periods, it shows no distinct actuations and elevated emissions during other periods. As a result, D-1’s emissions are significantly higher than emissions from D-4, shown in Fig. 11 as an example of a properly functioning intermittent vent controller.

Table 8: Summary of metadata relevant to device operation collected for PC D-1

PC Specific Data	Valve Operation ¹	EPA Type ²	Major Equipment ³	Process Variable	PC Make Model
PC D-1	Snap Acting	IV	Compressor	Liquid Level	Murphy L1200N

¹ 'Snap acting' or 'throttling' designation provided by station operator.

² Intermittent vent, low bleed or high bleed designation originally provided by station operator. Inconsistencies in EPA type identification were clarified and resolved by independent panel (Section S1-5)

³ Major equipment category where PC is operating. Compressor, dehydrator, separator, yard piping or acid gas removal unit.

A PC’s proportional band and supply gas pressure can have a significant effect on the expected emission rate and should be recorded in future studies.

During the final deployment of the field campaign, it was discovered that the flow meters used in the study recorded non-zero (referred to as NZ) flow rate values when the meter was pressurized, but gas was not flowing. Lab tests showed that readings increased with higher supply gas pressure



and decreased no near-zero at supply gas pressures below 30-35 psia. Flow meters installed in-line on PCs with supply gas pressures above 30-35 psia consistently exhibited NZ behavior.

Laboratory testing at METEC was performed to quantify NZ error [SI S1-4.2.1], establish meter specific pressure-NZ value correlations [SI S1-6], develop a data correction method based on these correlations [SI Table S1-1], and test the efficacy of the correction method under field conditions [SI S1-4.5]. A complete summary of corrections applied to each data set is outlined in SI S1-4.3. The results of these tests indicated that 42% of measured PCs were impacted by NZ error, to varying degrees. Data from 14 PCs (of 86 PCs sampled in total) were discarded after corrections were applied, as it appeared all gas flow recorded for those tests could be due to meter error [SI S1-7.4]. The severity of the impact on the remaining 72 successful measurements are summarized and discussed in SI S1-4.4. The data summaries provided [SI S1-7] are organized by severity of the NZ error on measurements.

The most significant implication of this meter error is the effective increase of the meter's lower detection limit at higher supply gas pressures. At pressures where a meter can show a false NZ reading, any actual flows below the NZ baseline are indistinguishable from meter noise. After correcting for this problem, there are restrictions on the use of the resulting data.

First, while the corrections have an impact on the average emission rates, they do not obscure the overall emissions behavior of the PC. Corrections only impact (i.e. obfuscate or even zero out) measured emission rates near the low end of the meter range. Measurements of higher emission rates, which define the overall behavior of the PC, are not impacted by this correction. Therefore, the measurements affected by NZ behavior can still be used for qualitative evaluation of PC emission behavior.

Second, the meter error and corrections have a non-uniform impact across the population of PC types. In particular, a subset of the population was discarded, which may impact certain types of emission behaviors disproportionately, and bias the remaining sample. Therefore, average emissions rates (i.e. emission factors) are impacted in an unknown, possibly biased, fashion and *should not*



be used for quantitative purposes, such as developing new emission factors for PCs in service at gathering stations.

The long-duration measurements recorded during this study provide insight into PC emissions behaviors that are not reflected in manufacturer's literature and have not been shown in prior studies. Analysis of recorded PC data shows a high degree of variability in operation over the course of hours or days, especially for intermittent vent PCs. PC data also show frequent occurrences of irregular emission behavior, inconsistent with intended operations.

To understand the qualitative behavior of the PCs, the study team assembled a panel of four industry experts to evaluate time series data from each PC. The panel first confirmed the EPA classification for each PC based on its make, model and service application. The panel and study team then categorized each PC's emission behavior as normal or abnormal. [SI S1-5] The panel developed rules to classify each PC as normally or abnormally operating:

High-bleed PCs were deemed to be operating normally if emissions were below the maximum specified by the manufacturer [SI S1-5.2]. The average emissions from all eight of the high-bleed PCs measured in this study were consistent with manufacturer specifications, and therefore operating normally from an emissions perspective.

Low-bleed PCs were deemed to be operating normally if average emission rates were below the EPA threshold of 6 scfh [SI S1-5.2]. Five of 24 low bleed PCs had average emissions that exceeded the 6 scfh threshold [SI Figure S1-24]. The average emission rates for these five abnormally operating PCs were much higher than the emission rates for normally operating PCs (34 [+20.57/-19.22] scfh vs 0.68 [+0.52/-0.43] scfh). These five PCs also had high emission rates throughout the measurement period.

Random sampling of short-duration (15 minute) samples from the multi-day data sets demonstrates that the emissions from both high-bleed and low-bleed PCs were generally consistent over the duration of recordings [SI Figure S1-23].

Intermittent-bleed PC's showed a wide range of emission patterns and required a more compre-

hensive set of criteria to categorize emission behavior. An example of emissions from a normally operating intermittent-bleed PC are shown in Figure 11.

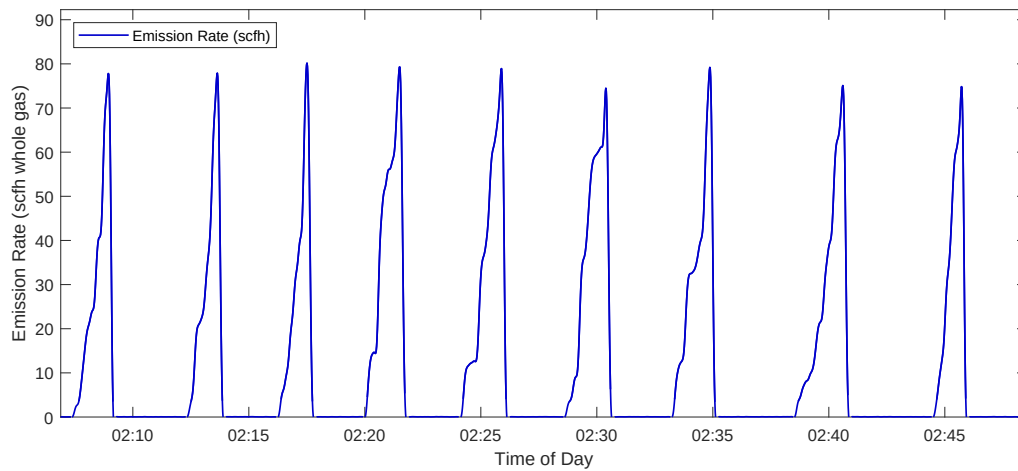


Figure 11: Time series emission data for a normally operating intermittent-bleed PC. This behavior is characteristic of intended operation; The emission profile shows distinct actuation events (ie. short peaks in emissions) that are < 3 minutes in duration, and emissions return to zero between each actuation event. 15 of 40 intermittent-bleed PCs measured in this study exhibited this expected emissions profile

For the population of intermittent-bleed PCs measured in this study, 15 exhibited this expected emissions behavior. The remaining 25 PCs showed unexpected emission patterns at some point during measurement. The industry panel evaluated the time series emission data for each of these 25 PCs and established four categories to classify abnormal emission patterns [SI S1-5.2]:

1. Continuous emission rates or lack of distinct actuation events [SI Figure S1-18]
2. An extended ramp up in emissions prior to actuation events [SI Figure S1-19]
3. Emissions not returning to zero between actuation events [SI Figure S1-20]
4. Other irregular behavior [SI Figure S1-21]

Approximately 50% of the intermittent-vent PCs that had abnormal emissions violated more

than one of the above criteria for abnormal operation. The criteria violated by each abnormally operating PC is shown in SI Table S1-22.

The time each intermittent vent PC exhibited abnormal emission behavior was variable. By assuming several parameters to define *normal* behavior, it is possible to calculate the amount of time each PC exhibited abnormal emissions using the criteria established by the expert panel. The algorithm uses signal processing to locate emission peaks in time series data [SI S1-2] and then makes the simple assumption that a “normal actuation” should last 3 minutes before, and 5 seconds after the peak. Any emissions within this time window are normal; any outside are attributed to abnormal behavior.

As an example, Figure 12 shows one recording shaded to highlight emissions occurring during abnormal operation. In this example, the majority of emissions are due to abnormal operation.

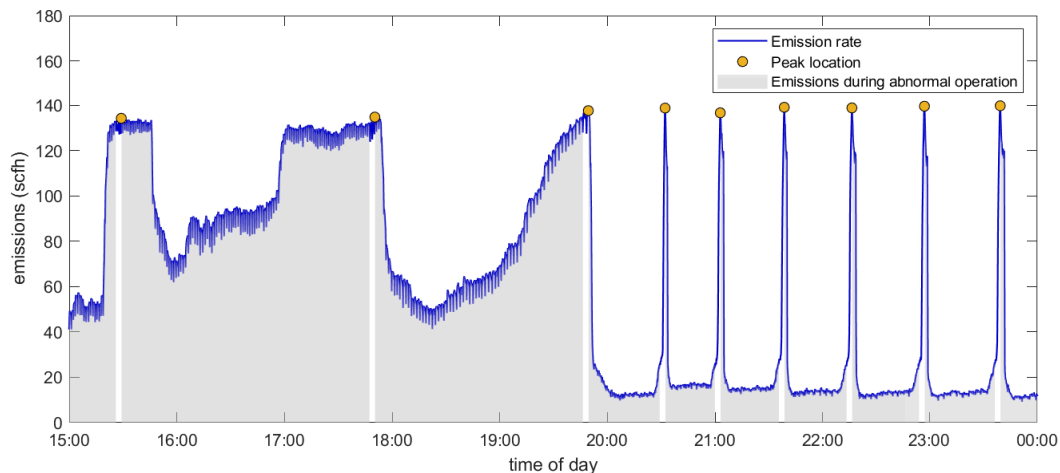


Figure 12: Time series of pneumatic controller emissions that exhibits multiple criteria for abnormal operation. The gray shaded area indicates times when the PC is emitting abnormally, based upon criteria established by an expert panel. Yellow circles indicate where control actuations were detected. Emissions for three minutes prior, and 15 seconds after, the yellow circle are considered normally-operating emissions. Over the first 7.5 hours of this recording the pneumatic controller emits gas continuously. At 19:50, the pneumatic controller begins showing distinct actuation patterns, but the actuation events last 8-10 minutes and emissions do not return to zero between events.



While new emission factors cannot be developed from the long-duration PC emission measurements, the data provide insight on the frequency of abnormal PC behavior, and its affect on emissions. The relatively high occurrence of abnormal behavior – 25 of 40 intermittent vent PCs – indicate that more information is needed.



4.4 Station Emissions

Station emissions estimates include estimates for all non-episodic methane emissions at a station, including fugitive and vented emissions, combustion slip, and flaring. Episodic emissions – primarily unit and station blowdowns – are not included to make the results comparable to previous studies which did not measure episodic events [3].

The field campaign measured emissions on 180 gathering stations, which represented 11% of all partner stations. Of the 180 stations, 177 stations had one or more units of major equipment screened and measured. The remaining 3 stations had no complete units of equipment screened and measured, either due to time constraints or weather conditions. All stations had at least one compressor, 54% had dehydrators, and 93% had atmospheric tanks. Stations ranged from small stations consisting of a single compressor skid with an electric motor drive to large facilities with more than 10 compressors.

Emissions for each station were computed by summing all of the emissions for the station. If a unit of major equipment was screened and measured, those emissions were used; if not, emissions were drawn from the major equipment emission factors developed in this study. Emissions from dehydrator and AGRU vents, flares, and pneumatic controllers were estimated using GHGRP methods and emission factors. Combustion slip was estimated as described elsewhere in this report. SI S3-5 discusses the modeling of each emission source in more detail.

Station emission estimates are provided in Table S3-44 in SI S3-5.1. Each station was classified by the type of equipment on the facility:

- *C*: Compression only
- *C/D*: Compression and dehydration
- *C/D/T*: Compression, dehydration and treating, i.e. acid gas removal.
- *C/T*: Compression and treating



The number of compressors at each station is also listed. While compressors vary widely in size, the number of compressors is a reasonable surrogate for station size. The table also lists the number of large emitters, electric compressors, and whether the station used instrument air for pneumatic controllers. For the 157 stations where throughput was available, throughput-normalized emissions are also provided in the table.

Station emissions span five orders of magnitude, from 0.00784 to 435 $kg \cdot h^{-1}$ CH₄. Throughput spans a similar range, from 0.03 to 260 MMscfd whole gas. While throughput and emissions are also correlated ($R^2 = 0.65$), the range of throughput-normalized emissions is similarly broad, at 0.0054% to 12% of throughput.

Figure 13 illustrates station emissions and correlation between throughput and emissions. While throughput and emissions are correlated, two groups of stations have different emission characteristics than the rest of the stations. First, the field campaign included 11 stations with only electric compressor drivers. These stations are also small - all have throughput in the bottom 14% of throughput. It is therefore impossible to separate the emissions impact of electrification from size. Second, 5 stations had throughput below 0.2 MMscfd, and also exhibited emissions lower than the trend line through all other stations. Both the electric and low throughput stations are of an atypical configuration, consisting of only one compressor skid and little other supporting equipment. While no definitive statements can be made, this type of small station appears to have throughput-normalized emissions that are lower than expected for their size and configuration.

Large emitters are scattered across a wide range of throughput and emission rates, exhibiting no clear trend. However, two of the top three emitting stations have two large emitters each, illustrating the impact of large emitters on station emission rates.

Visually, stations with instrument air appear to have emissions below the trend line, and thus lower than other stations, but the effect is not statistically significant. While instrument air indisputably lowers station emissions, the largest fraction of station emissions is combustion slip, which has substantial station-to-station variability, followed by the larger fugitive and vented emitters,

which are scattered between stations and therefore also highly variable. The variability in these factors dominates the overall variance in station emissions, and is large enough that the impact of instrument air is not independently visible.

Across all stations, 40% [32% to 45%] of all emissions are due to combustion slip – the largest category of methane emissions. Since combustion slip is strongly related to operating engine horsepower, and throughput is also a function of operating engine horsepower, combustion slip is the principal driver of the correlation between throughput and emissions. Fugitive and vented emissions account for a similar emission rate, 21% [13% to 37%] from yard piping, 21% [15% to 28%] from other major equipment, and 11% [8.9% to 13%] from pneumatic controllers. The remaining emissions are due to flares and AGRU and dehydrator vents.

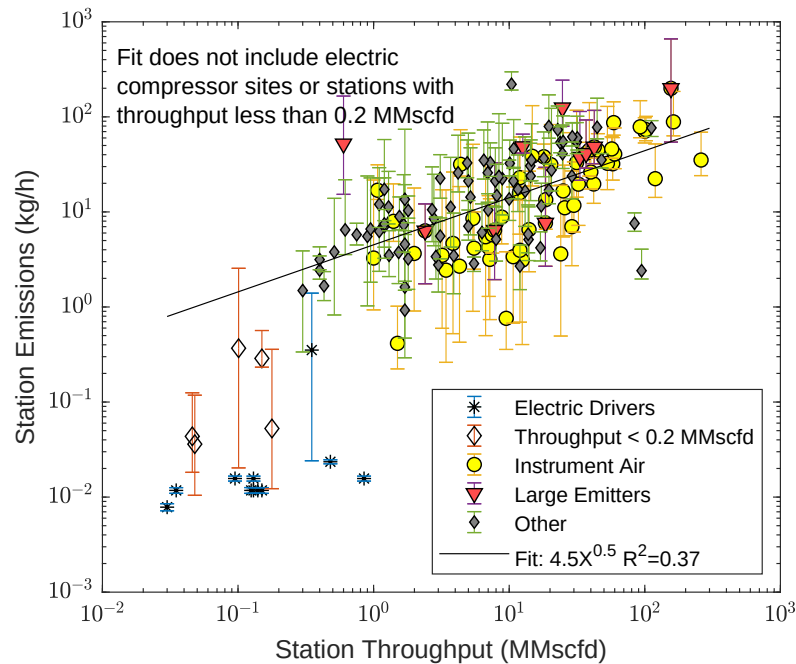


Figure 13: Emission rate as a function of throughput for the 157 stations in the field campaign where throughput data was available. Key characteristics of each station are indicated by point shape, including stations with all electric compressor drivers, stations where gas pneumatics and associated actuators are powered by instrument air, and stations with large emitters. Fit does not include 5 stations with throughput below 0.2 MMscfd or 11 small, all-electric, stations.



4.5 National Emissions

The national emissions model includes all emissions estimated for stations plus estimates for episodic emissions reported to the GHGRP. A primary focus of the national model was to test methods which could be readily replicated for inventories like the GHGI. Like station emissions, the estimate of U.S. national emissions utilizes major equipment emission factors for most emission estimates, coupled with GHGRP estimates for emissions from blowdowns, flares, dehydrator vents and AGRU vents. For activity data, the national model utilizes similar methods to the station estimate, but a largely independent source for the activity estimate: Station estimates used equipment counted during the field campaign, while the national model utilizes equipment counts reported to the GHGRP. The national estimate of emissions is computed by multiplying counts of major equipment units from the GHGRP by major equipment emission factors, and then scaling that estimate to account for units which are not reported to the GHGRP. [SI S3-6.]

GHGRP reports contain neither a station count nor a complete count of separators. To estimate these counts, scaling factors of stations per compressor and separators per compressor were developed from partner data. [SI S3-6.1] These scaling factors were developed *per-basin* to reflect differences in station size and configuration between basins; differences in produced gas composition and the age of the gathering infrastructure are reflected in the station size and design in a basin. Using the developed ratios, we estimate 2.8 [2.68 to 2.92] compressors per station on an average national basis.

While GHGRP reports contain compressor counts, they do not indicate the type of compressor driver, which had to be estimated from partner data to estimate combustion slip emissions.

Finally, GHGRP reports are required only when an operator's total GHG emissions exceed 25,000 mtCO₂eq annually. To account for major equipment units that are not reported to the GHGRP, the study scales reports using data about gas production in each basin. Overall, we estimate that 7.5% [6.6% to 8.5%] of stations are not reported to the GHGRP. [SI S3-6.2]

The method described here and in the supplementary volume is suitable for annually updating



national emissions from the gathering and boosting sector using annually-reported GHGRP activity data, and any emissions estimates or measurements also reported to the GHGRP.

Table 9 summarizes results from the national model. The study estimates national methane emissions of 1,484 [1,439 to 1,537] $Gg \cdot y^{-1}$, which is statistically lower than the current GHGI estimate of 1,955 $Gg \cdot y^{-1}$. In contrast, we estimate more stations nationally (6,108 [+4.4%/-4.3%]) than the current GHGI estimate of 5,241 stations. Both estimates reflect a larger number of smaller stations in this estimate, compared with previous work completed by Marchese et al.[4] using data from a 2013-14 field campaign [3]. Comparison of the two data sets indicates that the previous work sampled more complex stations – a higher fraction of stations with both compression and dehydration – that generally operated at higher throughput than this study. This differences may explain a substantial portion of the emissions difference, as discussed for station emissions in Section 4.4. Two factors lend credibility that this study may be a more representative, and more current, sample of gathering stations nationally: First, this study drew its sample from a larger partner station population (1705 stations versus ≈ 700 stations) provided by a more diverse set of operators (9 operators versus 4 operators). Second, activity data from the GHGRP, which was not available to the previous study, provides activity data from a large set operators for the entire U.S.

Additionally, in the intervening four years since the Mitchell measurements [3], methane emissions have received substantial attention in *all* natural gas sectors [29, 30]. As a result, there is anecdotal evidence that operators have placed additional emphasis on reducing emissions during operations and have emphasized lower emission designs when developing new stations.

Figure 14 illustrates the contributing categories for the national emission estimate. As with station emissions, combustion slip is the largest component of methane emissions for the sector, accounting for over 40% of emissions. Fugitive and vented emissions from compressors and tanks, as well as intermittent bleed pneumatic controllers, are also significant contributors. Nationally, approximately 71% of pneumatic controllers are intermittent bleed devices, and 24% are low continuous bleed devices.

Table 9: National and Station Summary of Emissions

Estimate	Total Methane Emissions ($Gg \cdot y^{-1}CH_4$)	Activity Factor (Stations)	Emission Factor ($kg \cdot h^{-1}station^{-1}CH_4$)
Marchese et. al [4]	1697 [1,512 to 1,886]	4,459 [3,756 to 5,380]	42.6 [34.6 to 52.6]
EPA GHGI[9]	1,955.1	5,241	42.6*
This Study	1,484 [1,439 to 1,537]	6,108 [5,846 to 6,374]	27.8 [26.3 to 29.3]
Mitchell et. al [3]		115	55.4 [41.5 to 72.3]
Study Field Campaign		180	23.3 [17.8 to 30.2]

* Current GHGI estimate for G&B uses the Marchese et al. emission factor.

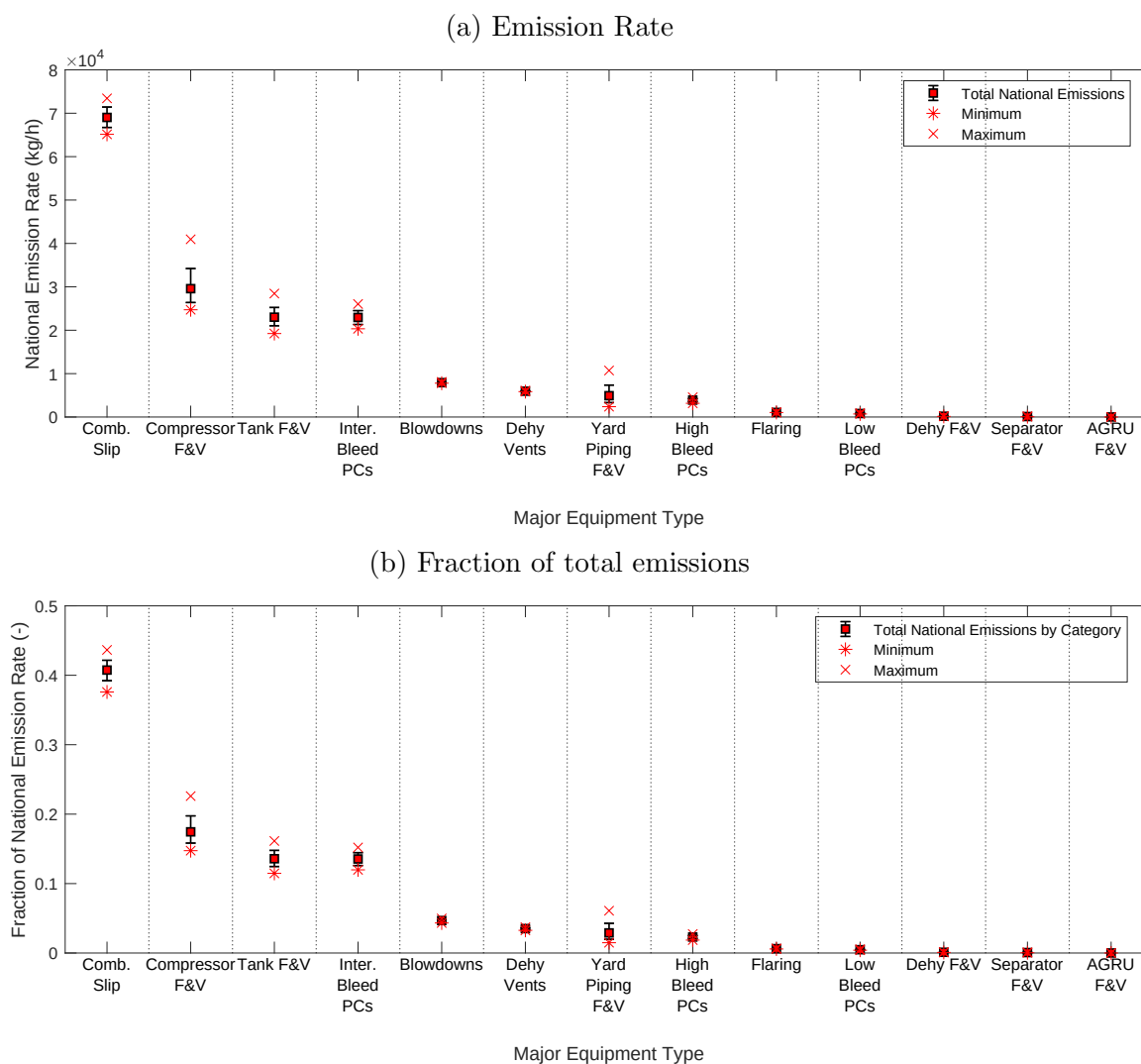


Figure 14: Estimated national emissions divided into categories by major equipment and emissions type. Top panel provides the emission rate for each category. Bottom panel indicates the fraction of total emissions in each category. Fugitive and vented emissions, including emissions from leaks and normally operating vents, are indicated as “F&V”. Combustion slip accounts for methane in combustion exhaust from compressor drivers, dehydrator vents for methane in dehydrator reboiler vents, and flaring for methane in flare combustion exhaust. Blowdowns include system and unit blowdown events; leak emissions through closed blowdown valves are included in the F&V emissions for the equipment units where the blowdown vents were located. Dehydrator vents, blowdowns, and flaring emissions were taken directly from GHGRP reports and not measured in the field campaign.



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PROFESSIONAL BACKGROUND

NEW MEXICO OIL & GAS ASSOCIATION

Senior Advisor

2020-Present

BESCO OPERATING, L.P., BOPCO/BEPCO, BASS ENTERPRISES PRODUCTION COMPANY FORT WORTH, TX

Vice President	2017-2020
Vice President – Regulatory and Governmental Affairs	2016-2017
Vice President – Operations	2005-2016
Division Production Manager	1994-2005
Division Engineer	1990-1994
Division Drilling and Production Superindendent	1987-1990
Sr. Production Engineer	1986-1987
Production Engineer	1981-1986

CAREER HIGHLIGHTS BY CATEGORY

PRODUCTION OPERATIONS

Managed operations of the largest division of the company (West Texas Division) first from 1987 to 1990 as Division Drilling and Production Superintendent and then again from 1994 to 2005 as Division Production Manager. While Division Production Manager, the division staff (office and field) developed the company's massive acreage position in southeast New Mexico in the lower Delaware formation (Brushy Canyon), Bone Spring, and Wolfcamp formations focusing on oil production and in the Pennsylvanian formations (Morrow and Atoka) focusing on gas production. Well over 100 vertical wells were drilled and completed along with attendant surface facilities and infrastructure. Hydraulic Fracturing was a key part of this development and our division led the company in propped fracture treatment design and application. During this same time we also redeveloped a significant acreage position within the Slaughter (San Andres) Field (Hockley County, Texas) by drilling slant-laterals to improve waterflood sweep efficiency. Beginning in 2005, as horizontal drilling became more established, as Vice President – Operations, I oversaw the development of infrastructure in New Mexico to support over 10,000 bbl/day of oil production, 120,000 bbl/day of water production and the attendant gas production with the goal of having all infrastructure in place before first production. This included building our own 58 MW electrical substation and distribution system that allowed the company to be completely free of expensive diesel-fueled electric generators by December of 2013 (well ahead of others in the industry). Further, the produced water gathering and disposal system was built with a capacity of over 180,000 bbls/day and was flexible enough by design to have a station go off-line and redirect water to other stations which would pick up the extra disposal volumes automatically. As VP – Operations, I was responsible for managing the Environmental, Safety, and Health department for the company. This department was responsible for facility permitting and greenhouse gas reporting among other duties. I was also responsible for opening a new Division office in Denver to oversee our gas well development in the Piceance Basin of northwest Colorado. Besides drilling difficult gas wells, this included the creation and oversight of a gas gathering system, a gas processing plant and a produced water gathering and disposal system.

ENGINEERING

Created a novel reservoir management process in the Keystone (Ellenburger) Field (Winkler County, Texas) that resulted in the incremental recovery of over 100 BCF and over 1 MMBO from a reservoir where all other WI owners had concluded that there was nothing more to be done other than gas cap blow-down. Process involved producing water at a high enough rate to outrun the aquifer and "drain" the reservoir. As difficult as this was from an engineering and operational perspective, the real challenge was to create a way for the entire field to be managed this way without a field-wide unit. This was done through several highly technical and highly contentious

Texas Railroad Commission hearings where we created a set of field rules which incentivized all parties to participate voluntarily while protecting individual operator's rights.

Was involved in the development of several software and data management systems for the company. Designed and created a downhole failure tracking system which included creating field event diagnosis training and a field data entry process, personally created a database and a software application for our local area network that all engineers and field management could use to identify and diagnose problem wells early enough to avoid more repeated failures and thus cut operating costs.

Developed a software application to aid engineers (including myself) in the management of oil and gas remaining reserves. This system was eventually used as the foundation for the company's entire reserves management system.

Managed the development of a complex information dashboard through professional programmers that allowed non-technical employees to have access to technical information stored in various databases and information repositories throughout the company. This system accessed over a dozen different data sources across most functional divisions of the company.

INDUSTRIAL AND POLITICAL RELATIONS

Selected as a **Distinguished Lecturer by the Society of Petroleum Engineers** for the 2020-2021 season. Through that role, I presented a lecture on an engineer's role in creating a safe work environment based on facts our company discovered during an investigation of an accident that occurred at a wellsite during a foam-air well intervention.

Led or had significant roles in these major programs:

- 1) Organized and led an industry workgroup which led to the creation of the **Candidate Conservation Agreement** to protect the Dunes Sagebrush Lizard (DSL) and the Lesser Prairie Chicken (LPC). These programs protected these candidate species while preserving the ability to develop oil and gas resources for all participants in the program.
- 2) Led the creation of the current federal rules as to how oil and gas would be developed within the Secretary of the Interior's Potash Area of southeast New Mexico. I was selected as co-chair representing the oil and gas industry interests in an oil and gas/potash joint industry committee. The committee created a joint recommendation to the Secretary of the Interior which resulted in the **2012 Secretarial Order** establishing overarching principles to be used to govern co-development of oil and gas and potash resources in the roughly 500,000 acre potash area. The new order opened vastly more drilling for oil and gas while protecting the resources of the potash industry.

GOVERNANCE

Member and Chair of Board of Trustees, Trinity School of Midland (private pre-k through 12th college preparatory); Member Board of Trustees, Fort Worth Country Day School (private pre-k through 12th college preparatory).

EDUCATION

B.S. Petroleum Engineering degree with Honors, University of Texas - 1980.

Engineer in Training certification 1981

Industry schools:

Rike - Workovers and Completions

Van Poolen - Advanced Log Analysis

Managing People for Success

Introduction to Reservoir Simulation

Hydrogen Sulfide Certification

Other

PERSONAL

Married since 1983, father of two. Eagle Scout, 1973. Enjoy reading, golf, tennis, travel. Former deacon First Presbyterian Church, Midland, Texas.

Adam T. Meyer

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Summary of Qualifications

Advanced degreed mechanical engineer with management experience specializing in gaseous, fluid, and heat transfer systems. Experienced in facility design and troubleshooting, reliability, and root cause analysis. Detail-oriented and excels in high-stress situations and projects with rigorous schedules.

Education

B.S. in Mechanical Engineering, Pennsylvania State University (August 2002)

M.S. in Mechanical Engineering, Fundamentals of Thermal Fluid Transport, University of Florida (May 2010)

Continuing Education Coursework: ASME Process Piping, Pro-E, NX, AFT Arrow and Fathom Courses, SINDA/FLUENT Training, REASONS Root Cause Analysis Training

Selected Upstream Accomplishments

- Expert on upstream facility design for compliance, with specialty in atmospheric tank closed vent system (CVS) analysis and design. Advisor on industry panels on the subject (<https://www.colorado.gov/pacific/cdphe/air-oilandgas-storage-tank-guidelines>). Developed dynamic model and standardized methodology for analysis of oil production facility CVS in accordance with Quad Oa.
- Co-invented the Tank Emission Management System (TEMS) to replace Quad Oa design analysis requirement. Developed protocols, controls narratives, and supporting calculations to determine proper installation and success. "Closed Loop Vapor Control System" have been accepted by EPA (See EPA's "New Owner Self Audit Policy") and state of Colorado.
- Identified root cause for large 42,000 bopd CPF atmospheric tank venting. Orchestrated test protocol and instrumentation placement. Root cause of venting caused by dissimilar produced water and oil tank diameters and fill rates, which led to synchronization of pipeline produced water and pipeline oil pumps. Resolved issue with low cost automation changes.
- Resolved H2S scavenger system issues related to scaling and tank VRU fouling. Designed intermediate separation system and resolved the issue.
- Designed produced water truckloadout station that was implemented and verified on 17 facilities in Eagle Ford.
- Designed two bradenhead/casing gas abatement on-pad solutions. These low-cost skids meet and exceed all regulatory requirements and has been implemented at over 50 facilities in first year.
- Scoped solution and executed (as project manager) two midstream compressor station brownfield projects. Leveraged vendors and engineering firms and coordinated all project deliverables.
- Developed Victaulic piping specification (first of its kind) to provide low cost facility builds.
- Designed system with compressor serving dual purpose as wellhead compressor (to bring up plunger) and vapor recovery unit (to maintain first stage separator pressure low), resulting in higher gas recovery.
- Developed new apparatus for pressurized liquid sampling with Alliance Source Testing, leading to more accurate results for RVP, TVP, and flash gas-oil-ratio (GOR)

Related Experience

Valor EPC Inc, CO**Principal, VP US Operations****(March 2021 - present)**

Owner and Vice President of Operations in the US focused on energy industry. Manages operations, resourcing, and leads business development and vision of the company. Coordinates with project teams and workflow on small to large scale projects such as production facilities, gas plants, and booster station builds. Manages finances, insurance, and in-house policies and procedures. Acting project manager on several projects at any given time.

Lansera LLC, CO**Owner, Sole Proprietor****(Jan 2020 - present)**

Provides environmental technology and solutions to the oil and gas industry to resolve industry issues such as atmospheric tank venting, bradenhead gas abatement, and flare gas elimination. Bridges the air permitting and facility engineering world to provide practical solutions.

ZAP Oilfield Solutions, CO**Director, Oilfield Solutions****(Sept 2018 – Jan 2020)**

Directed business of ZAP Oilfield Solutions (ZOFS) reporting to president of ZAP Engineering. Wore multiple hats on a day-to-day basis. Focused on generating environmental technical solutions for clients and directed engineering team (ZOFS). Oversaw manager of ZOFS and department of eight (8) engineers, designers, and programmers. Grew business and client relations. Evaluated market needs and developed common environmental solutions for the benefit of multiple customers. Project manager on up to five (5) projects at a time including new production facility design and engineering projects. Instituted new business concepts to ZAP such as expedited rates and third-party facility monitoring services.

Manager, Oilfield Solutions**(Jan 2018 – Sept 2018)**

Created R&D and upstream O&G business unit (ZAP Oilfield Solutions) of ZAP Engineering with focus on upstream solutions and facility design. Acted as subject matter expert (SME), lead analyst, and manager. Managed five (5) employees and up to thirteen (13) projects at any given time. Developed business plan for ZAP Oilfield Solutions and product rollout, performed financial outlook assessments, and presented status reports to upper management. Managed timesheets and project schedules. Worked with EPA and CDPHE on behalf of operators, and became trusted technical authority on both sides.

ZAP Engineering and Construction Services, CO**Senior Mechanical Engineer****(Oct 2014 – Jan 2018)**

Mechanical engineer for piping systems at compressor stations, gas processing facilities, oil production facilities, and continued support for NASA KSC facilities in Florida. Developed P&IDs, specifications, calculations, conducted engineering trade studies, valve sizing, separation equipment sizing, perform site inspections and performed complex modeling of facility operations. Evaluated over 1500 oil production facilities in Colorado, Utah, Wyoming, North Dakota, Texas, and Ohio. Developed new methods, technologies, and designs for oil production facilities.

Kennedy Space Center, FL**Fluid / Cryogenic System Design Engineer****(Oct 2012 – Oct 2014)**

Cryogenic system analyst and subject matter expert (SME) for Pressure Vessel / System (PV/S) Certifications. Designed cryogenic and pneumatic systems for the Mobile Launcher, Launch Equipment Test Facility (LETF) and other NASA projects. Ensured new designs complied with ASME Pressure Vessel and B31 codes. Performed thermal analysis, valve sizing, flexhose flow induced vibration analyses, pipe stress analyses using Caesar II, relief valve and vent sizing, water hammer analysis, vessel structure and support analysis, and

remaining life analysis using API579 and other life-prediction methods. Generated valve, pipe, and flexhose technical specifications for cryogenic components.

Thermal / Fluid Systems Design Engineer

(Oct 2007 – Jan 2011)

Design engineer for cryogenic and pneumatic Ground Support Systems (GSS) supporting the Space Shuttle. Developed 3D models, P&IDs, drawings, conducted engineering trade studies, pressure vessel / system (PV/S) inspections and certifications per ASME BPV and ASME B31 series, relief valve sizing and vent system design, and performed thermal, fluid/gas flow, and stress calculations. Conducted field strain gauge tests and performed structural stress analyses. Design flame trench transducer cooling system and received NASA awards for quick turnaround. Developed API 579 fitness for service calculations and programs still used to this day.

Reliability Engineer

(Dec 2004 – Oct 2007)

System reliability engineer for Liquid Hydrogen (LH2) and Hypergolic Fuel and Oxidizer GSE. Generated Failure Modes and Effects Analyses (FMEAs), fault trees, root cause analyses, and hazard analyses. Served as panel member on the USA System Safety Review Panel (SSRP). Led ARES project to complete ten (10) analyses ahead of schedule.

Siemens Energy, Service Engineering, Orlando, FL

Auxiliaries and Controls Engineer

(Jan 2011 – October 2012)

Auxiliaries and controls engineer providing support of gas turbine service fleet. Provided short turnaround troubleshooting and solutions to field issues related to gas turbine control logic and auxiliary systems. Performed fluid pressure drop, valve sizing, pipe support stress analyses, field walkdowns, developed drawings, BOM, and construction instructions for service products. Systems included cooling air, lube oil, fuel gas and oil, and BOP boiler and piping systems. Performed R&D testing for low pressure, high flow manifolds. Areas of responsibility covered many disciplines at detailed levels.

General Dynamics, Electric Boat Corporation, Groton, CT

Engineer

(Sept 2002 – Sept 2004)

Piping systems engineer supporting construction of Seawolf Class submarine trim and drain, water, and atmosphere monitoring systems. Performed mission critical engineering trade studies and analyses for SUBSAFE and DSS-SOC programs, and Missile Defense. Performed material evaluations and statistical hazard analyses. Obtained DOD Secret Clearance.

Computer Competencies

Microsoft Word, Excel, Project

MATLAB

Caesar II (Pipe Stress Analysis Software)

AFT Fathom, Arrow (Fluid, Gas Flow Programs)

NASGRO

Microstation 2D / AutoCAD / Smartdraw

Awards

EPA Clean Air Excellence Award (2019)

NASA Space Flight Awareness Honoree Award (2009)

NASA Space Flight Awareness Local Recognition Award (2014)

<https://sfa.jsc.nasa.gov/searchform.cfm>

JUSTIN M. LISOWSKI P.E.

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SENIOR PROJECT MANAGER & FACILITY SPECIALIST**PROFESSIONAL EXPERIENCE**

VALOR EPC, Wheat Ridge, CO 2021 – Current

Senior Project Manager & Facility Specialist

Oversee and manage capital projects for clients across a diverse discipline range covering front end engineering design (FEED) to fabrication and construction. Provide subject matter expertise for rotating equipment, engine emission retrofit technologies and compliance, and maintenance programs.

OTFOX SERVICES CO. LLC., Monument, CO 2017 – Current

Principal Engineer

Engineering consulting and fabrication services provider.

- FEED design review for waste-water treatment technology in the Tequila industry. Identified opportunities to streamline manufacturing, reduce overall costs, and reduce water contaminants by over 50%, allowing for surface discharge disposal.
- Metalworks – design and fabrication for industrial and architectural

OVINTIV INC. (FORMERLY ENCANA OIL & GAS (USA) INC.), Denver, CO 2007 – 2020

Senior Facilities Engineer and Infrastructure Planning Coordinator, Texas Ops**2019 – 2020**

Designed, oversaw construction, and provided engineering and operational support for oil, gas, and water handling facilities. Coordinated with asset manager to devise strategic infrastructure plans and initiatives and communicated and partnered with stakeholders to identify timing, planning considerations, and development constraints.

- Delivered on \$4M facility design, constructed and online ahead of schedule and under budget by 15% through optimization of equipment and creative redeployment of equipment from older facilities.
- Directed infrastructure plans for \$1.1B development program, meeting 100% of proposed production schedule by determining potential bottlenecks and influencing long-term plans to allow lead-time.
- Identified strategic infrastructure plan to implement dual fuel on 3rd-party hydraulic fracturing and drilling operations, replacing 25% of diesel usage with natural gas, and decreasing fuel costs by 25%.
- Decreased standardized facility cost by \$200K through design and implementation of reduced tank facility, without introducing additional downtime.
- Onboarded new vendors for all tanks and pressure vessels, resulting in 25% cost reduction, while ensuring critical design criteria, manufacturing schedules, and quality standards were maintained.

Senior Engineer, Business and Corporate Development**2016 - 2019**

Identified and evaluated corporate acquisitions consistent with company strategy. Provided analysis of target basin infrastructure, take away constraints, and modelling drilling, completions, and facility costs.

- Performed critical due diligence for \$7.7B Encana-Newfield merger (closed Q1 2019), preparing target company operational analysis and generating daily financial updates to executive team.
- Developed target company scoping tool reducing initial evaluation time over 75% by screening mergers and acquisition (M&A) opportunities, maintaining up-to-date key basin understandings, and tracking opportunities and potential trigger points.
- Evaluated and prepared valuation reports on target companies, leading to acquisition negotiations and offers on 4 corporate merger opportunities.

Lead, Development, Exploration and Emerging Plays 2014 - 2016

Assessed and analyzed revolving set of emerging plays to determine placement in future portfolio.

OVINTIV EXPERIENCE CONTINUED:**Permian Data Trade Manager (2016)**

- Met and negotiated directly with basin competitors, executing strategic data trades to accelerate company learnings.
- Negotiated and executed 8 data trades with Permian operators, leveraging and expanding company's \$16M science dataset by estimated \$22M (+140%).

Lead Engineer, Tuscaloosa Marine Shale (2015)

- Performed asset development planning and reservoir engineering while leading team of 3, ensuring development and reservoir characterization tasks were completed on time and accurately via steering budget, financial outlook reports, annual reserves, land retention strategy, and execution.
- Directed deep dive analysis for asset, presenting comprehensive findings to executive team, showcasing enhanced development plan to increase well productivity by 33%.
- Presented plan to improve individual well rate of return by 50% through optimized drilling costs, high intensity stimulation with revised cluster design, and improved fracture conductivity coupled with revised production drawdown.

Piceance Niobrara Asset Development Manager (2014 – 2015)

- Spearheaded assessment, progressing project through stage gate process, providing recommendations to add to company portfolio, and partnering with Bureau of Land Management (BLM) for paying well determination, lease retention drilling requirements, and navigating regulatory requirements.
- Executed \$50M exploration budget, drilling 2 wells for production and geological tests with comprehensive coring plan, demonstrating scalability to 1K BBL / day production and play to achieve target production of 50K BBL / day.
- Generated infrastructure development plan, providing strategic synergies with neighboring Piceance Williams Fork program for water recycling and eliminating 100% of water disposal costs.

Manager, Rotating Equipment - Technical Services**2013 - 2014**

Supervised cross-border, Canadian / USA Rotating Equipment Team of 9, comprised of equipment and maintenance specialists and engineers. Evaluated improvement opportunities across all operating areas focused on increasing production volumes and equipment runtime and improved data management to extrapolate learnings into future facilities designs.

- Cut compressor downtime over 50% through implementation of Compressor Health Optimization Program (CHOP) while increasing production on average of 15% and optimizing fuel consumption.
- Directed study of drilling rig power and fuel usage to understand optimal operation and power needs across all operations.
- Enacted power management system saving 30% in fuel, delivering line-of-sight recommendations for more active generator management coupled with natural gas, to save an additional 50%.

Rotating Equipment Engineer, Technical Services**2009 - 2013**

Provided subject matter expertise (SME) in USA division, including equipment design and retrofit, troubleshooting, and emission compliance. Served as facilitator, speaker, and instructor for training courses, forums, and multiple industry conferences.

- Restored operations on 2 shut down engines due to emission compliance violations by conducting field analysis and troubleshooting, bringing \$200K / day revenue back online.
- Commissioned \$1M in research testing of solutions for future emission regulations and new technologies for fuel consumption improvements.
- Created and implemented predictive maintenance techniques, minimizing failures of key equipment and reducing unplanned shutdown events by 80%.
- Launched computerized maintenance management system (CMMS), streamlining and improving scheduling processes, equipment tracking, and demonstrating sustainable reduction in maintenance costs of 37%.
- Achieved warranty resolutions ranging between \$100K and \$2M through data analysis of major failures and leading joint efforts with distributors and manufacturers to reach unique solutions, ensuring joint future work was enriched.
- Authored 3 company equipment specifications and recommended practices, adhering to best safety practices.

Previous **Ovintiv (Encana) Roles (2007 – 2009): Completions Engineer, N. Rockies Business Unit, Jonah Field | Facilities Engineer, Tech. Business Solutions, Midstream Business Unit | Reservoir Engineer, New Ventures, Play Assessments**

EDUCATION

Master of Science (MS), Mechanical Engineering, Colorado State University, Fort Collins, CO
Bachelor of Science (BS), Mechanical Engineering, Colorado State University, Fort Collins, CO

LICENSURE

Colorado Professional Engineering (PE) Licensure 2018

DENNIS E. MCNALLY
SENIOR SCIENTIST
ALPINE GEOPHYSICS, LLC

EDUCATION:

M.S. Atmospheric Sciences, University of California, Davis, California, 1994.

B.S. Chemical Engineering, Emphasis in Computer Science, University of Colorado, Boulder, Colorado, 1987.

PROFESSIONAL EXPERIENCE:

Senior Scientist, Alpine Geophysics, Arvada, CO, 1990-Present.

Staff Scientist, Radian Corporation, Sacramento, CA, 1987-1990.

Student Assistant II, National Center for Atmospheric Research, Boulder, CO, 1985-1987.

FIELDS OF EXPERIENCE:

Dennis McNally is an Atmospheric Scientist interested in applied air quality studies. He provides project management, programming and modeling expertise for advanced photochemical and mesoscale meteorological modeling studies. He possesses a practical knowledge of the physical sciences and the computer science skills essential in mathematical modeling of environmental systems. His education has been strengthened by practical experience in atmospheric transport and process modeling through his participation in the Regional Acid Deposition Model (RADM) development program at the National Center for Atmospheric Research (NCAR). Mr. McNally was honored by being selected as a participant in the 1990 NCAR Summer Colloquium on Mesoscale Data Assimilation. His areas of expertise include the following:

Photochemical Modeling

Mr. McNally has been a central participant in over 50 studies involving the application of state of science photochemical modeling systems. His experience ranges from chemical mechanism development to modeling to support regulatory issues. Over the last decade Mr. McNally has experience with the CALPUFF, CAMx, UAM-V, UAM-IV, UAM-2, ROM 2.2, MAQSIP, SAQM and Models-3/CMAQ photochemical models. Mr. McNally has conducted numerous photochemical modeling training courses for both industrial and government groups.

Meteorological Modeling

Dennis has extensive experience with the application of meteorological models *for air quality* applications. His experience ranges from application of fairly simplistic objective/diagnostic models for screening analyses to state of science prognostic models to address regional transport. He has experience with the CSUMM, MM5, RAMS and WRF prognostic meteorological models and the CALMET diagnostic model for applications in numerous government and industry-sponsored studies. Mr. McNally has conducted several training courses for various state and local government agencies.

Model Performance Evaluation

A key component to the application of meteorological and photochemical models is comparison to observations. As the developer of the MAPS model performance evaluation tool, Mr. McNally has taken evaluation techniques out of academia and made them available to the regulatory community.

Selected Project Experience

SESARM VISTAS2. Client: Southeastern States Air Resource Managers, Inc. (SESARM), 2017 – 2020. Alpine is performing the regional haze photochemical modeling and analysis to assist the southeastern states in crafting regional haze state implementation plans.

North Slope Regional Air Quality Modeling. Client: Bureau of Land Management, 2018 – 2020. Alpine is reviewing the BOEM Arctic study and updating the modeling platform for use by BLM reviewing projects in Northern Alaska.

Galveston Bay Refining Inter-pollutant Trade. Client: Blanchard Refining, 2018. Alpine performed an analysis showing the ozone air quality benefit of offsetting the VOC emissions from a refinery modification with NOx emission credits.

Entergy Inter-pollutant Trade. Client: Entergy. 2017. Alpine performed an analysis showing the ozone air quality benefit of offsetting the VOC emissions from a power generation turbine with NOx emission credits.

Petronova Inter-pollutant Trade. Client: Petronova, 2013. Using the CAMx photochemical model, Alpine performed an analysis showing the ozone air quality benefit of offsetting the VOC emissions from a flue gas carbon capture project in the Houston area with NOx emission credits.

Celanese Methanol Inter-pollutant Trade. Client: Celanese Ltd, 2013. . Using the CAMx photochemical model, Alpine performed an analysis showing the ozone air quality benefit of offsetting the VOC emissions from a methanol technology project in the Houston area with NOx emission credits.

Ozone NAAQS Analysis. Client: Midwest Ozone Group, 2000 – Ongoing. Generate a base and projection year modeling platform and execute CAMx for ozone in order to provide input on potential technical activities available to support interested parties in the review, analysis, and planning for NAAQS attainment in the Midwestern and eastern U.S. Develop a future year culpability assessment using OSAT/APCA and prepare incremental studies on source apportionment and emissions and air quality trends for domestic and international sources.

Denver/Northern Front Range State Implementation Plan. Client: ENVIRON/Regional Air Quality Council, 2008 – 2021. Alpine is conducting SMOKE emissions and CAMx photochemical modeling in support of the Denver/Northern Front Range 8-hour ozone State Implementation Plan (SIP). This SIP modeling includes development of a June 2006 and Summer 2011 baseline photochemical modeling databases, emissions sensitivity testing to assist in developing candidate control strategies and detailed control strategy emissions development and photochemical modeling.

Greater Monument Buttes Oil and Gas Project. Client: Newfield Exploration, 2014. Alpine used the CMAQ air quality model and SMOKE emissions model to examine the impacts of a proposed oil and gas project in the Uintah Basin of Utah.

Marathon Resid Oil Upgrader and Capital Development. Client: Marathon Petroleum, 2014. Using the CAMx photochemical model, Alpine performed modeling to estimate the ozone impact of a proposed refinery expansion in Louisiana.

Uintah Basin 2013 Winter Ozone and Air Quality Study. Client: Utah Division of Air Quality. 2013. Alpine participated in synthesis and presentation of the 2013 Winter Ozone Study examining elevated ozone levels in rural Utah.

Moneta Divide Environmental Impact Statement. Client: BLM Lander Field Office, 2013. Alpine and a team of other consultants are using photochemical modeling to examine the air quality impacts of the Moneta Divide project emissions in central Wyoming.

Sasol Lake Charles. Client: Sasol North America, 2013. Using the CAMx photochemical model, Alpine performed modeling to estimate the ozone impact of a proposed petrochemical complex expansion in Louisiana.

Cameron Liquefied Natural Gas. Client: Cameron LNG, 2013. Using the CAMx photochemical model, Alpine performed modeling to estimate the ozone impact of a proposed liquefied natural gas export terminal in Louisiana.

Uintah Basin 2012 Winter Ozone and Air Quality Study. Client: Utah State University. 2012. Alpine participated in synthesis and presentation of the 2012 Winter Ozone Study examining elevated ozone levels in rural Utah.

BLM Carlsbad Field Office – Permian Basin Air Quality Impacts Analysis. Client: URS/BLM. 2012. Alpine applied the SMOKE emissions model and CAMx photochemical model over the Permian Basin to assist in air quality planning the basin.

Wyoming Meteorological Modeling for Ozone Impact Analysis. Client: Wyoming Department of Environmental Quality. 2011. Alpine was the lead modeling contractor preparing annual Weather Research and Forecasting (WRF) meteorological fields for an annual 2008 simulation and provided assistance for development of higher resolution simulations.

Chukchi Sea WRF Modeling. Client: ConocoPhillips, 2011. Alpine applied the WRF Mesoscale meteorological model over Alaska and the Chukchi Sea for the months of July through November for the years 2007, 2008 and 2009 for subsequent use in the CALMET model to compute air quality impacts of a proposed development operation. Included in the project was an operational model evaluation comparing the model results to available observation data.

Western Regional Air Partnership (WRAP) West-wide Jump Start Air Quality Modeling Study (WestJumpAQMS). Client: Western Regional Air Partnership, 2011. Using the WRF mesoscale meteorological model, the SMOKE emissions model and the CAMx photochemical model, Alpine conducted photochemical modeling in the Western United States to assist in air quality planning.

Cheniere Sabine Pass Liquefaction. Client: Cheniere, 2011. Using the CAMx photochemical model, Alpine performed modeling to estimate the ozone impact of a proposed liquefied natural gas export terminal in Louisiana.

Allegheny County PM2.5 State Implementation Plan. Client: Allegheny County Health Department, 2011. Using the WRF mesoscale meteorological model, the SMOKE emissions model and the CAMx photochemical model, 2 Alpine is conducting both regional and local scale modeling to assess the impact of local and regional scale emissions on the residual non-attainment at monitors in the Liberty/Clairton area.

Houston Stakeholder Modeling. Client: Consortium of Industrial Groups in Greater Houston Area, 2010. Using the WRF Mesoscale meteorological model, the SMOKE emissions model and the CMAQ and CAMx air quality models, Alpine is exploring ensemble meteorological and air quality modeling to develop potential air quality control options in the Houston, TX area.

Single Source Ozone Impact Analysis in the Gulf Coast. Client: Trinity Consultants/Cheniere Energy, Inc., 2011 Using the Baton Rouge Louisiana SIP photochemical modeling system Alpine assessed the potential ozone impacts of a proposed natural gas liquefaction facility in Cameron Parish, Louisiana.

Mesoscale Model Interface Formatter (MMIF) Statistical Software Development. Client: General Services Administration (GSA), 2010. Developed a statistical package to compare the MMIF model results against routinely available meteorological observations.

Chapita Wells Oil and Gas Project. Client: EOG Resources, 2009. Alpine is using CMAQ air quality model and SMOKE emissions model to examine the impacts of a proposed oil and gas project in the Uintah Basin of Utah.

EPA 2005 MM5/WRF. Client: EPA Office of Air Quality Planning/GSA, 2008. Applied the MM5 mesoscale meteorological modeling for calendar 2005 to develop base case meteorology for future air quality modeling and to apply the WRF model to select periods during the year to intercompare WRF and MM5 model performance.

Pennsylvania Biofuels. Client: E.H. Pechan and Associates/Pennsylvania DEP, 2009. Using the Mobile 6/SMOKE emissions models and the CMAQ air quality model, Alpine assessed the ozone and particulate air quality impact of increased biofuel penetration within the commonwealth.

Nucor Steel Louisiana, Client: Environmental Resource Management/Nucor Steel, 2008. Using a preliminary release of the Baton Rouge Louisiana SIP photochemical modeling system Alpine assessed the potential ozone impacts of a proposed pig iron facility.

Greater Natural Buttes. Client: AECOM/Anadarko Petroleum, 2008 – 2012. Under the NEPA process Alpine is applying the CMAQ model for base years 2005 and 2006, and a future year of 2018 to examine alternative development scenarios in the Uinta Basin. In addition to the CMAQ modeling, this study involved application of the Western Regional Air Partnership (WRAP) emissions database using the SMOKE emissions modeling system.

Four Corners Ozone Task Force CAMx. Client: ENVIRON/New Mexico Environment Department, 2007 – 2010. As a subcontractor to ENVIRON, Alpine is assisting in developing a summer 2005 CAMx photochemical modeling episode over the Four-Corner region of Arizona, Colorado, New Mexico and Utah. This modeling database will then be used to assess a variety of emissions sensitivity experiments to determine both the current causes of high ozone in the area and to assist in future air quality planning.

Baton Rouge Stakeholder Air Quality Modeling. Client: Industry Consortium, 2006-Present. Under contract to a consortium of industrial clients, Alpine has developed and evaluated a summer 2005 CAMx modeling database over Baton Rouge, LA to examine ozone culpability in the region and to assist the State of Louisiana in developing an 8-hour ozone State Implementation Plan. Included in this project are source apportionment simulations and future year emissions sensitivity assessments.

VISTAS Emissions and Air Quality Modeling. Client: VISTAS, 2003 - Present. VISTAS is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility, and other air quality issues in the southeastern United States. Alpine Geophysics, LLC, is part of a team performing the Phase II Emissions and Air Quality Modeling for VISTAS. The cornerstone of the Phase II activities is performing annual emissions and regional PM/ozone modeling of 2002, 2009, and 2018 using the SMOKE/CMAQ/MM5 modeling system.

SIP Strategy Comprehension Plan (SSCP). Client: Industry Consortium, 2005 - 2007. The objective in developing this plan was to describe the components of an integrated 8-hour ozone and annual PM_{2.5} modeling study for the five-state Upper Midwest region. The aim of the SSCP is to develop a process allowing the project sponsors insight and assurance that best modeling practices are being utilized to identify effective emission reduction controls to address the residual nonattainment issues in this region, and that if alternate and credible information is developed independently outside of the scope, timelines, or budgets of the RPO recommendation process, that these data are introduced to the states in a constructive manner for consideration in SIP development timelines. This plan was implemented by Alpine in preparing MM5 meteorological, SMOKE and photochemical modeling of 2002, 2005, 2008 and 2015 and presentation of the results to both the regulators and the regulated industry.

San Juan County Early Action Compact. Client: Air Quality Bureau, New Mexico Environment Division, 2003 - 2004. Performed MM5 meteorological, emissions, and photochemical modeling for multiple ozone episodes to assist the state in application of an Early Action Compact to EPA. Included preparation of protocol documents, quality assurance documents, and community outreach presentations, and delivery of comprehensive training to division staff and interested parties.

Central California Ozone Study (CCOS) Ambient Ozone. Client: Valleywide Air Pollution Study Agency, 2005-2006. The primary object of this study was to advance the present understanding of air quality in central California, with specific emphasis on ozone formation and ozone levels in the San Joaquin Valley. The geographic domain of interest included the entire region of Central California Ozone Study, which in addition to the San Joaquin Valley incorporates the Sacramento Valley, the San Francisco Bay Area, and the central California coast. In order to do this, we needed to clarify the relationships between trends in ambient ozone data and trends in the stationary, area, on-road mobile, non-road mobile, and biogenic sources emissions inventories. This study involved application of the MM5 model, the EMS-95 emissions model and the CAMx photochemical model instrumented with advanced process analysis.

Holnam Evaluation. Client: U.S. EPA, Region 7, 2002. Performed CAMx photochemical modeling to assess the potential ozone air quality impacts of a proposed Portland cement manufacturing plant upwind of the St. Louis non-attainment area. Tasks performed during this project included:

- Obtaining all relevant modeling databases and proposed facility emissions estimates from the Missouri Department of Natural Resources and confirm proper operation of the model on the Alpine Geophysics computer network;
- Modifying the inputs to UAM-V to include the nitrogen oxide and hydrocarbon emissions from the proposed facility;
- Running the UAM-V with the modified emission files;
- Interpreting the results of the modeling on the ozone attainment status in St. Louis

Peninsular Florida Ozone Study. Client: Florida Department of Environmental Protection (FL DEP), 2000 - 2002. The objectives of this study were to: (1) set up and evaluate advanced emissions, meteorological, and photochemical modeling tools for up to nine 8-hour ozone episodes affecting the Tampa, Orlando, and Jacksonville areas (three episodes per area); (2) examine potential emissions control strategies that would attain and/or maintain the new 8-hour standard in the region; and (3) assist in the development of the technical analyses supporting a "weight of evidence" attainment demonstration to be used by FL DEP for regulatory decision-making and in developing its State Implementation Plan (SIP) submittal to the EPA. To accomplish these objectives, the following technical approach was implemented:

- Assess the nature and extent of ozone episodes in the central Florida region and develop a quantitative procedure for classifying and selecting modeling episodes for 8-hour modeling;
- Prepare an Ozone Modeling Protocol that guides the adaptation, evaluation, and use of emissions, meteorological, and photochemical models for the region;
- Prepare appropriate emissions, meteorological, and air quality model input data sets for up to nine multiple-day episodes suitable for 8-hour ozone attainment demonstration modeling in the individual Tampa, Orlando, and Jacksonville areas or across the entire Peninsular Florida region as a whole;
- Conduct model evaluation analyses following draft EPA 8-hour ozone guidelines (EPA, 1999) in order to estimate the adequacy and reliability of the photochemical modeling system and datasets;

- Develop future year baseline emissions projections in the Peninsular Florida region based on the best projections of emissions growth and control in the region;
- Exercise the photochemical modeling system with the future-year emissions estimates for the selected episodes to ascertain whether the new 8-hour standard is attained. If attainment is not modeled in the baseline scenario, examine pertinent emissions reduction scenarios aimed at demonstrating attainment for the episode; and
- Develop a suitable "weight of evidence" analysis supporting the ozone attainment demonstration, consistent with EPA guidance.

PROFESSIONAL SOCIETIES:

Air and Waste Management Association
American Meteorological Society
American Chemical Society

PUBLICATIONS:

Journal Papers:

"Ethylene Source Attribution Modeling in the Greater Houston Area", *Atmospheric Pollution Research*, (with others), Vol. 8, pp. 1016-1022.

"Preliminary Evaluation of the Community Multiscale Air Quality Model for 2002 over the Southeastern United States", *Journal of the Air & Waste Management Association*, (with others), Vol. 65, pp. 1694-1708, 2005.

"Evaluation of CALGRID Using Two Different Ozone Episodes and Comparison to UAM Results", *Atmospheric Environment*, (with others), Vol. 28, No. 17, pp. 2823-2845, 1994.

"Photochemical Modeling of Two SCCAMP Ozone Episodes," (with T. W. Tesche), *Journal of Applied Meteorology*, Vol. 30, pp. 745-763.

Conference Proceedings and Presentations:

"Application of EPA's Flexible Attainment Demonstration Guidance to the Pittsburgh-Beaver Valley Ozone Nonattainment Area", (with T. W. Tesche) 10th Joint Conference on Applications of Air Pollution Meteorology, Phoenix, AZ, 11-16 January, 1998.

"Assessment of the Reliability of the OTAG Modeling System", (with others), 10th Joint Conference on Applications of Air Pollution Meteorology, Phoenix, AZ, 11-16 January, 1998.

"Final Evaluation of the MM5 Model for the 3-6 August 1990 SARMAP Episode over Central California", (with others), 10th Joint Conference on Applications of Air Pollution Meteorology, Phoenix, AZ, 11-16 January, 1998.

"Nested Regional Photochemical Modeling in Support of the Pittsburgh-Beaver Valley Ozone SIP", (with others), 10th Joint Conference on Applications of Air Pollution Meteorology, Phoenix, AZ, 11-16 January, 1998.

"Evaluation of the MM5, SAQM, UAM-IV, and UAM-V Models Over the Northeast U.S. for Four Ozone Episodes Using Routine and Intensive NARSTO-NE and LMOS Aerometric Data Sets", (with T. W. Tesche), First NARSTO-NE Data Analysis Symposium and Workshop, Washington, D.C., 10-12 December, 1996.

"Application of the SAQM, URM, and UAM-V Photochemical Models to the Southern California SCAQS-97 Domain", (with others), Ninth Joint Conference on Applications of Air Pollution Meteorology, Atlanta, GA, 28 January-2 February 1996.

"Evaluation of the MM5 Model for the July 1988 and July 1995 Episodes and Comparison with the OTAG Meteorological Model, RAMS", (with T. W. Tesche), 89th Annual Meeting of the Air and Waste Management Association, 23-28 June 1996, Nashville, TN.

"Relationships Between Ozone Precursor Controls Needed to Meet 1-Hr and 8-Hr Ozone NAAQS in San Francisco and Chicago", (with T. W. Tesche), 89th Annual Meeting of the Air and Waste Management Association, 23-28 June 1996, Nashville, TN.

"Evaluation of the URM, UAM-V, UAM-IV, and ROM2.2 Photochemical Models Over Lower Lake Michigan for Two 1991 LMOS Oxidant Episodes", (with others), Ninth Joint Conference on Applications of Air Pollution Meteorology, Atlanta, GA, 28 January-2 February 1996.

"Application of the Emissions Modeling System EMS-95 to the Southern California SCAQS-97 Domain", (with others), Ninth Joint Conference on Applications of Air Pollution Meteorology, Atlanta, GA, 28 January-2 February 1996.

"Numerical Simulation of Mesoscale Circulation Development in the San Diego Air Basin", Tropospheric Ozone and the Environment II, Air and Waste Management Association, 5-7 Nov. 1991, Atlanta, GA.

"Development of the Annual Average Urban Airshed Model (3AM) with Application to the Los Angeles Basin," (with T. W. Tesche), presented at the Symposium on Atmospheric Modeling, American Chemical Society, 10-15 Sept. 1990, Miami, FL.

"Ozone Control Implications Revealed by Airshed Model Isopleths," 82nd Annual Meeting of the Air and Waste Management Association, 25-30 June, 1989, Anaheim, CA.

"Role of Windfield Estimation in Airshed Modeling for Ozone Non-Attainment Planning," (with others) 81st Annual Meeting of the Air Pollution Control Association, 21-25 June, 1988, Dallas, TX.

"Importance of Boundary Layer Measurements for Urban Airshed Modeling," (with others) 81st Annual Meeting of the Air Pollution Control Association, 21-25 June, 1988, Dallas, TX.

"Incorporation of Monte Carlo Simulation Techniques into the R-RAM II Health Risk Assessment Model," 81st Annual Meeting of the Air Pollution Control Association, 21-25 June, 1988, Dallas, TX.

Company Reports (Selected)

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: Final Modeling Protocol”, (with others), prepared for SESARM, Inc., Stockbridge, GA, June 2018.

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: 2011el and 2028el CAMx Benchmarking Report”, (with others), prepared for SESARM, Inc., Stockbridge, GA, August 2018.

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: 2011el CAMx Version 6.32 and 6.40 Comparison Report”, (with others), prepared for SESARM, Inc., Stockbridge, GA, December 2018.

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: 2011el CAMx Version 6.40 12km VISTAS and EPA 12km Continental Grid Comparison Report”, (with others), prepared for SESARM, Inc., Stockbridge, GA, December 2018.

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: 2028 CAMx Version 6.32 and 6.40 12km Comparison Report”, (with others), prepared for SESARM, Inc., Stockbridge, GA, April 2019.

“Regional Haze Modeling for Southeastern VISTAS II Regional Haze Analysis Project: 2028elv2 CAMx Version 6.40 12km VISTAS and EPA 12km Continental Grid Comparison Report”, (with others), prepared for SESARM, Inc., Stockbridge, GA, May 2019.

“Ozone Impact Analysis of the Proposed Resid Oil Upgrader Expansion and Capital Development Project”, (with Cynthia Loomis), prepared for Sage Environmental Consulting, Metairie, LA, 11 December 2014.

“Ozone and PM_{2.5} Impact of the Proposed Sasol Lake Charles Gas-to-Liquids and Lake Charles Cracker Projects”, (with Cyndi Loomis), prepared for Sasol North America Inc., Houston, TX, 15 November 2013.

“Ozone Impact Analysis of the Proposed Cameron LNG Facility”, (with Cyndi Loomis), prepared for Cindy Thompson, C-K Associates, Baton Rouge, LA, 29 April 2013.

“Application and Evaluation of WRF for August through October 2010” (with Cyndi Loomis) prepared for Louisiana Foundation for Excellence in Science, Technology and Education, (2012).

“Western Regional Air Partnership (WRAP) West-wide Jump Start Air Quality Modeling Study (WestJumpAQMS) WRF Application/Evaluation” (with others), prepared for Western Regional Air Partnership, (2012).

“Evaluation of 36/12 km WRF for Calendar Year 2008 over the Continental and Western United States”, (with others), prepared for Wyoming Department of Environmental Quality (2011).

“Winter 2008 WRF Modeling of the Upper Green River Basin”, (with others), prepared for Wyoming Department of Environmental Quality, (2011).

“Application and Evaluation of WRF for Calendar Year 2007”, (with Cyndi Loomis), prepared for Allegheny County Health Department, (2011).

“ConocoPhillips Chukchi Sea WRF Modeling Application, Model Application and Evaluation”, (with J.G. Wilkinson), prepared for AECOM, (2011).

“Ozone Impact Analysis of the Proposed Cheniere Sabine Pass Liquefaction Facility”, (with Cyndi Loomis), prepared for Trinity Consultants, (2011).

“Evaluation of Air Quality Impacts of Biofuels in Pennsylvania”, (with others), prepared for Commonwealth of Pennsylvania Department of Environmental Protection Bureau of Air Quality, (2009).

“Technical Support Document for VISTAS Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans”. (with others), prepared for Visibility Improvement State and Tribal Association of the Southeast (VISTAS), (2009).

“Technical Support Document for the Association of Southeastern Integrated Planning (ASIP) Emissions and Air Quality Modeling to Support PM_{2.5} and 8-Hour Ozone State Implementation Plans”, (with others), prepared for Southeastern States Air Resource Managers, Inc. Association for Southeastern Integrated Planning, (2009).

“Final 2010 Ozone Attainment Demonstration Modeling for the Denver 8-Hour Ozone State Implementation Plan”, (with others), prepared for the Denver Regional Air Quality Council, (2009).

“Ozone Impact Analysis of the Proposed Nucor Steel Louisiana Facility”, (with Cyndi Loomis), prepared for Environmental Resource Management, (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2004 over the Continental and Western United States with Emphasis in Western Colorado, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2005 over the Continental and Western United States with Emphasis in Western Colorado, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2006 over the Continental and Western United States with Emphasis in Western Colorado, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2004 over the Continental and Western United States with Emphasis in Southwestern Wyoming, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2005 over the Continental and Western United States with Emphasis in Southwestern Wyoming, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12/4 km MM5 for Calendar Year 2006 over the Continental and Western United States with Emphasis in Southwestern Wyoming, (with J.G. Wilkinson), prepared for Arcadis-US, Inc. (2008).

“Evaluation of 36/12 km MM5 and WRF for February and August 2005 over the Continental and Western United States”, (with J.G. Wilkinson), prepared for USEPA Office of Air Quality Planning and Standards (OAQPS), (2008).

“Evaluation of 36/12 km MM5 for Calendar Year 2005 over the Continental and Western United States”, (with J.G. Wilkinson), prepared for USEPA Office of Air Quality Planning and Standards (OAQPS), (2008).

“2010 Ozone Attainment Demonstration Modeling for the Denver 8-Hour Ozone State Implementation Plan Control Strategy”, (with others), prepared for the Denver Regional Air Quality Council, (2008).

“2010 Ozone Projections for the 2010 Base Case and 2010 Sensitivity Test and 2010 Ozone Source Apportionment Modeling for the Denver 8-hour Ozone State Implementation Plan”, (with others), prepared for Denver Regional Air Quality Council, (2008).

“Model Performance Evaluation for the June-July 2006 Ozone Episode for the Denver 8-hour Ozone State Implementation Plan”, (with others), prepared for Denver Regional Air Quality Council, (2008).

“Evaluation of Preliminary MM5 Meteorological Modeling Simulation for the June-July 2006 Denver Ozone SIP Modeling Period Focused on Colorado, (with others), prepared for Denver Regional Air Quality Council, (2008).

“Modeling Protocol for the Denver 8-Hour Ozone Attainment Demonstration Modeling”, (with others), prepared for Denver Regional Air Quality Council, (2007).

“Evaluation of 36/12 km MM5 For Calendar Year 2006 Over the Continental and Western United States”, (with G. J. Schewe), prepared for ENSR Corporation, (2007).

“Evaluation of 36/12/04 km MM5 for Calendar Year 2005 focused on the Upper Midwest”, (with G. J. Schewe), prepared for the Midwest Ozone Group, (2006).

"Evaluation of 36/12/04 km MM5 for Calendar Year 2003, (with G. J. Schewe), prepared for New Mexico Environment Department, (2006).

"Evaluation of 36/12/04 km MM5 for Calendar Year 2004, (with G. J. Schewe), prepared for New Mexico Environment Department, (2006).

"Evaluation of 36/12/04 km MM5 for Calendar Year 2005, (with G. J. Schewe), prepared for New Mexico Environment Department, (2006).

"CENRAP BART Modeling Guidelines", (with others), prepared for Central Region Air Planning Association, (2005).

"Annual Application of MM5 to Support 1994 Calpuff Air Quality Modeling, Final Report", (with T. W. Tesche), prepared for USEPA, Region XIII, (2003).

"Operational Evaluation of the MM5 Meteorological Model Over the Continental United States: Protocol for Annual and Episodic Evaluation", (with others), prepared for the U. S. EPA, Office of Air Quality Planning and Standards, (2002).

"Annual Application of MM5 to Support 1994 Calpuff Air Quality Modeling, Modeling Protocol", (with T. W. Tesche), prepared for USEPA, Region XIII, (2002).

"Modeled Effects of SO₂ and NO_x Emissions Controls on Power Plants in and Upwind of New York on Annual and Seasonal Sulfate and Nitrate Deposition at Sensitive Receptors", (with T.W. Tesche), prepared for NRG Energy, Inc., (2002).

"Meteorological Modeling for the Southern Appalachian Mountains Initiative (SAMI), (with others), prepared for the Southern Appalachian Mountain Initiative, (2002).

"Operational and Scientific Evaluation of the MM5 Meteorological Model over the Continental United States: Protocol for Annual and Episodic Evaluation", (with others), prepared for the U.S. EPA, Office of Air Quality Planning and Standards, (2002).

"A Comparison of MM5 Model Estimates for February and July 2001 Using Alternative Model Physics Options". (with T. W. Tesche), prepared for the U.S. EPA, Office of Air Quality Planning and Standards, (2002).

"A Comparison of MM5 Model Estimates for February and July 2001 Using Alternative Input Databases". (with T. W. Tesche), prepared for the U.S. EPA, Office of Air Quality Planning and Standards, (2002).

"Peninsular Florida Ozone Study (PFOS): Volume 3: Final Report", (with others), prepared for the Florida Department of Environmental Protection. (2002).

"Development of Base Year and Future Motor Vehicle Emissions for the 25 August-1 September 2000 Episode", (with others), prepared for the BCCA-AG, (2001).

"CAMx Flexi-Nesting Simulations of Short Duration VOC Emissions on 8 September 1993 in Houston", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"Comparative Evaluation of MM5 and RAMS Meteorological Simulations of the 6-11 September 1993 Episode", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"CAMx Model Sensitivity to Choice of Horizontal Advection Scheme: Tests with the 6-11 September 1993 COAST Episode", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"Assessment of the Ozone Impacts of Rescinding the 55 MPH Speed Limit and Lawn Care and Construction Ban Control Measures in the 8-County Houston/Galveston Nonattainment Area", (with others), prepared for the BCCA-AG, (2001).

"Initial Evaluation of the MM5/MAQSIP-RT Forecast Model for the 27 August-1 September 2000 Modeling Episode", (with others), prepared for the BCCA-AG, (2001).

"Evaluation of Recent CAMx Simulations of the 6-11 September 1993 Episode Using Alternative Meteorological Drivers", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"Ozone Source Apportionment Modeling of the 6-11 September 1993 Episode", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"CAMx and MAQSIP Model Performance Evaluation with THOE Hours and Modeling Artifact Stations Removed", (with T. W. Tesche), prepared for the BCCA-AG, (2001).

"Relationships Between Concentrations of Highly Reactive VOCs and Concentrations of Photochemical Oxidants in the 8-County Houston/Galveston Nonattainment Area", prepared for the BCCA-AG, (2001).

"Analysis of the Ozone Air Quality Impacts of the Proposed Holnam, Inc. Portland Cement Manufacturing Plant", (with T. W. Tesche), prepared for the USEPA, Region VII, (2001).

"Uncertainty in Ozone Model Predictions", prepared for the Midwest Ozone Group, (2001).

"Evaluation of CAMx and Models-3/CMAQ Over the Lower Lake Michigan Region with Inputs from the RAMS3c and MM5 Models", (with others), prepared for the Coordinating Research Council, (2001).

"Weight of Evidence Analyses Suggesting Attainment of the 1-hr Ozone Standard in the Baton Rouge Region", (with T. W. Tesche), prepared for NRG Energy, (2001).

"Assessment of Current Information on the Impact of Western Missouri Electric Generating Units on 1-Hr Ozone Attainment in St. Louis", prepared for Blackwell Sanders Pepper & Martin, LLP, (2000).

"Assessment of the Adequacy of Relative Reactivity Factors and Photochemical Grid Models in Estimating the Ozone Impacts of Reformulated Gasoline", prepared for the U.S. Environmental Protection Agency, (2000).

"Peninsular Florida Ozone Study (PFOS): Volume 2: Data Exchange Protocol", (with others), prepared for the Florida Department of Environmental Protection, (2000).

"Peninsular Florida Ozone Study (PFOS): Volume 1: Ozone Modeling Protocol (Ver.1.0)", (with others), prepared for the Florida Department of Environmental Protection, (2000).

"Review of the EPRI/MOG UAM-V Monte Carlo Uncertainty Study", prepared for the Midwest Ozone Group, (1999).

"Verification of the EMS-95 Benchmark Simulations of the July 1995 SAMI Oxidant Episode over the Southeastern U.S.", (with T. W. Tesche), prepared for the Southern Appalachian Mountains Initiative, (1999).

"Impact of Stack Parameter Errors on Ground Level Ozone Metrics in the OTAG Domains", (with others), prepared for General Motors Corporation, (1999).

"Verification of the RAMS3c Benchmark Simulations of the 9-19 July 1995 SAMI Oxidant Episode over the Southeastern U.S.", (with T. W. Tesche), prepared for the Southern Appalachian Mountains Initiative, (1999).

"MM5 Performance Evaluation for the 15-24 June 1995 and Assessment of Model Suitability for 8-Hr Ozone Attainment Demonstration over the Kansas City-St. Louis, Missouri Domain", (with others), prepared for the Kansas Department of Health and Environment and the Missouri Department of Natural Resources, (1999).

"Modeling Ozone, Visibility (Fine Particles), and Wet Deposition for Three Episodes", (with others), prepared for the Southern Appalachian Mountains Initiative, (1999).

"Impact of Incorrect Grid M Point Source Emissions Data on Ozone Model Performance and Year 2007 CAA and SIP Call Projections", (with others), prepared for the Indiana Electric Association, (1999).

"Appraisal of OTC Plans for 8-HR Ozone Attainment Demonstration Modeling over Portions of the Ozone Transport Region", prepared for the Midwest Ozone Group, (1999).

“Ozone Modeling Protocol for the Pennsylvania Stakeholders Study”, (with others), prepared for the Pennsylvania Department of Environmental Protection, (1999).

“Estimation of Emissions Reduction Targets for the Pennsylvania Stakeholders Study”, (with others), prepared for the Pennsylvania Department of Environmental Protection, (1999).

“Comparison of Photochemical Model Performance in Several Studies in the Lower Lake Michigan Region”, prepared for the Coordinating Research Council, (1999).

“Comparison of Photochemical Model Performance in Several Studies in the Northeast U.S.”, prepared for the Coordinating Research Council, (1999).

“Comparative Evaluation of the MM5 and RAMS3c Prognostic Meteorological Models Over the Midwestern U.S. for Two 1999 LMOS Intensive Measurement Episodes”, (with T. W. Tesche), prepared for the Coordinating Research Council, (1999).

“Evaluation of Models-3 Ozone Predictions in LMOS and Northeast Domains”, (with others), prepared for the Coordinating Research Council., (1999).

“Examination of Emissions Reduction Targets for the Pennsylvania Stakeholders Study”, (with others), prepared for the Pennsylvania Department of Environmental Protection. (1999)

“Ozone Modeling Protocol for the Kansas City Nonattainment Area”, (with others), prepared for the Kansas Department of Health and Environment, (1999).

“Evaluation of the MM5 Meteorological Model Over the Greater Denver Front Range Region for Two Wintertime Episodes”, (with T. W. Tesche), prepared for the Denver Regional Air Quality Council, (1998).

“Tri-State Regional Ozone Modeling Study: Results of the Sub-Regional Modeling of the EPA Section 110 SIP Call”, (with others), prepared for the Greater Cincinnati Chamber of Commerce, (1998).

“Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 1: Ozone Modeling Protocol”, (with T. W. Tesche), prepared for the Ohio EPA and the Kentucky Natural Resources and Environmental Protection Cabinet, (1998)

“Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 2: Episode Selection Report”, (with T. W. Tesche), prepared for the Ohio EPA and the Kentucky Natural Resources and Environmental Protection Cabinet, (1998)

“Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 5: Evaluation of the MM5 Model for the 18-22 June 1994 Episode”, (with others), prepared for the Ohio EPA and the Kentucky Natural Resources and Environmental Protection Cabinet, (1998).

“Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 6: Interim Attainment Demonstration”, (with others), prepared for the Ohio EPA and the Kentucky Department of Natural Resources, (1998).

“Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 8: Final Report”, (with others), prepared for the Ohio EPA and the Kentucky Department of Natural Resources, (1998).

“Photochemical Modeling Analysis of the Effects of VOC and NOx Emissions Reductions on 1-hr and 8-hr Ozone Concentrations in Kentucky”, (with others), prepared for Louisville Gas and Electric Co., (1998).

“Photochemical Modeling Analysis of the Effects of VOC and NOx Emissions Reductions in the Kansas City Nonattainment Area on 1-hr and 8-hr Ozone Concentrations”, (with others), prepared for Kansas City Gas and Electric Co., (1998).

“Photochemical Modeling Analysis of the Subregional Effects of the EPA Section 110 SIP Call Within and Downwind of the State of Virginia”, (with others), prepared for AlliedSignal, Inc., (1998).

“Analysis of the Effects of VOC and NOx Emissions Reductions in the Eastern United States on Peak 1-hr and 8-hr Ozone Concentrations”, (with others), prepared for the Midwest Ozone Group, (1998).

- “Review of the EPA Ozone Transport SIP Call and Recent Post-OTAG Modeling and Analysis Studies”, (with others), prepared for the Ohio EPA and the States of Kentucky and West Virginia, (1998).
- “Effects of Indiana Point Source NOx Emissions Reductions on Ground Level Ozone Concentrations Using the 07EPA1a Base Case Inventory”, (with T. W. Tesche), prepared for the Indiana Electric Association, (1998).
- “Photochemical Modeling Analysis of the Effects of Electric Utility NOx Emissions Reductions in Eastern Missouri on 1-Hr and 8-Hr Ozone Concentrations”, (with others), prepared for the Missouri Electric Utility Environmental Committee, (1998).
- “Photochemical Modeling of the Effects of Electric Utility NOx Emissions Trading on Eastern U.S. Ozone Concentrations”, (with others), prepared for First Energy Corp, Akron, Ohio. (1998)
- “Modeled Effects of Indiana Point Source NOx Emissions Reductions on Local and Regional 1-Hr and 8-Hr Ground Level Ozone Concentrations in 1995 and 2007 Using Two OTAG Oxidant Episodes”, (with T. W. Tesche), prepared for the Indiana Electric Association, (1998).
- “Evaluation of the MM5 Meteorological Model Over the Greater Denver Front Range Region for Two Wintertime Episodes”, (with T. W. Tesche), prepared for the Denver Regional Air Quality Council, (1998).
- “Tri-State Regional Ozone Modeling Study: Results of the Sub-Regional Modeling of the EPA Section 110 SIP Call”, (with others), prepared for the Greater Cincinnati Chamber of Commerce, (1998).
- “Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 5: Evaluation of the MM5 Model for the 18-22 June 1994 Episode”, (with others), prepared for the Ohio Environmental Protection Agency and the Kentucky Natural Resources and Environmental Protection Cabinet, (1998).
- “Cincinnati-Hamilton Ozone Attainment Demonstration Study: Volume 8 C Final Report”, (with others), prepared for the Ohio EPA and the Kentucky Department of Natural Resources, (1998).
- “Photochemical Modeling Analysis of the Effects of VOC and NOx Emissions Reductions on 1-hr and 8-hr Ozone Concentrations in Kentucky”, (with others), prepared for Louisville Gas and Electric Co., (1998).
- “Photochemical Modeling Analysis of the Effects of VOC and NOx Emissions Reductions in the Kansas City Nonattainment Area on 1-hr and 8-hr Ozone Concentrations”, (with others), prepared for Kansas City Gas and Electric Co., (1998).
- “Photochemical Modeling Analysis of the Subregional Effects of the EPA Section 110 SIP Call Within and Downwind of the State of Virginia”, (with others), prepared for AlliedSignal, Inc., (1998).
- “Analysis of the Effects of VOC and NOx Emissions Reductions in the Eastern United States on Peak 1-hr and 8-hr Ozone Concentrations”, (with others), prepared for the Midwest Ozone Group, (1998).
- “Review of the EPA Ozone Transport SIP Call and Recent Post-OTAG Modeling and Analysis Studies”, (with others), prepared for the Ohio EPA and the States of Kentucky and West Virginia, (1998).
- “Effects of Indiana Point Source NOx Emissions Reductions on Ground Level Ozone Concentrations Using the 07EPA1a Basecase Inventory”, (with T. W. Tesche), prepared for the Indiana Electric Association, (1998).
- “Photochemical Modeling Analysis of the Effects of Electric Utility NOx Emissions Reductions in Eastern Missouri on 1-Hr and 8-Hr Ozone Concentrations”, (with others), prepared for the Missouri Electric Utility Environmental Committee, (1998).
- “Modeled Effects of Indiana Point Source NOx Emissions Reductions on Local and Regional 1-Hr and 8-Hr Ground Level Ozone Concentrations in 1995 and 2007 Using Two OTAG Oxidant Episodes”, (with T. W. Tesche), prepared for the Indiana Electric Association, (1998).
- “A Critical Review of Regulatory Air Quality Modeling for Tropospheric Ozone”, (with others), prepared for the American Petroleum Institute in support of the North American Research Strategy for Tropospheric Ozone (NARSTO), Washington, D.C. (1998).

- “Evaluation of the MM5 Model for Two 1993 Regional Ozone Episodes over the Gulf Coast”, (with T. W. Tesche), prepared for the Offshore Operators Committee and the Minerals Management Service, (1998).
- “Comparative Evaluation of the CAMx and UAM-V Models Over the Northeastern U.S. Using the July 1995 OTAG Episode and the NARSTO-NE Intensive Field Study Data”, (with T. W. Tesche), prepared for the Virginia Department of Environmental Quality, (1997).
- “Modeled Effects of Indiana Point Source NO_x Emissions Reductions on Local and Regional 1-hr and 8-hr Ground Level Ozone Concentrations in 1995 and 2007 Using Two OTAG Oxidant Episodes”, (with T. W. Tesche), prepared for the Indiana Electric Utility Air Workgroup, (1997).
- “Comparative Evaluation of the CAMx and UAM-V Models Over the Northeastern U.S. Using the July 1995 OTAG Episode and the NARSTO-NE Intensive Field Study Data”, (with T. W. Tesche), prepared for the Virginia Department of Environmental Quality, (1997).
- “Application of the SAQM Model to Alternative Year 2007 Emissions Control Scenarios for the July 1991 OTAG Episode”, (with others), prepared for the Midwest Ozone Group, (1997).
- “Photochemical Modeling Analysis of the Pittsburgh-Beaver Valley Ozone Nonattainment Area: Volume VI -- Attainment Demonstration”, (with others), prepared for the Pennsylvania Department of Environmental Protection, (1997).
- “Protocol for the Development of a 2007 SIP Call Emissions Inventory”, (with others), prepared for the Ohio Environmental Protection Agency and the Missouri Electric Utility Environmental Committee, (1997).
- “Development of the 2007 Emissions Inventory Reflecting the EPA Section 110 SIP Call Requirements for the Eastern U.S.”, (with others), prepared for the Ohio Environmental Protection Agency and the Missouri Electric Utility Environmental Committee, (1997).
- “State-Specific Photochemical Modeling Analyses Using the July 1995 and July 1991 OTAG Modeling Episodes”, (with T. W. Tesche), prepared for the Ohio Environmental Protection Agency, (1997).
- “Photochemical Modeling Analysis of the Northwest ‘Ozone Free’ OTAG States Using the July 1995 OTAG Modeling Episode”, (with T. W. Tesche), prepared for Minnesota Power, (1997).
- “The Use of the San Joaquin Valley Meteorological Model in Preparation of a Field Program in the South Coast Air Basin and Surrounding Regions of Southern California: Volume 1 -- Final MM5 Evaluation for the 3-6 August 1990 SARMAP Episode”, (with others), prepared for the California Air Resources Board, (1997).
- “The Use of the San Joaquin Valley Meteorological Model in Preparation of a Field Program in the South Coast Air Basin and Surrounding Regions of Southern California: Volume 2 -- Numerical Modeling Studies for the Development and Application of a Guidance Technique to Support the Design of the 1997 Southern California Ozone Study Field Program”, (in support of Dr. Seaman and others), prepared for the California Air Resources Board, (1997).
- “Comparative Evaluation of the SAQM and UAM-V Models For the 13-21 July 1991 OTAG Episode”, (with T. W. Tesche), prepared for the Midwest Ozone Group, (1997).
- “Analysis of Airshed Isopleths in the Lower Lake Michigan Region with Emphasis on the Levels of Control Needed to Mitigate Onshore 1-hr and 8-hr Average Ozone Impacts”, (with others), prepared for the American Petroleum Institute, (1996).
- “Evaluation of the MM5 Model for the 1-11 July 1988 OTAG Episode Over the Northeastern United States”, (with T. W. Tesche), prepared for Pennsylvania Power and Light, (1996).
- “Comparative Evaluation of the MM5 and RAMS Models for the July 1991 OTAG Episode”, (with T. W. Tesche), prepared for the Midwest Ozone Group, (1996).

"Pittsburgh Regional Ozone Attainment Study: Volume X -- Evaluation of the MM5 Model for Three 1995 Regional Ozone Episodes over the Northeast United States", (with T. W. Tesche), prepared for the Southwestern Pennsylvania Clean Air Stakeholders Group, (1996).

"Evaluation of the Technical Basis for PM-10 Control Requirements in the South Coast Air Basin", (with others), prepared for the Western States Petroleum Association, (1989).

"PM-10 Impacts of the SCAQMD and WSPA Alternative Plans", (with others), prepared for the Western States Petroleum Association, (1989).

"An Analysis of Gas Phase Chemical Mechanisms for the Modeling of Hydrogen Peroxide Formation in the Troposphere" (with W.R. Stockwell). National Center for Atmospheric Research, Boulder, Colorado, 1986.



Mr. Nichols is a professional engineer in Texas with over 24 years of experience specializing in water and carbon management. He began his career working for an oil field service company as a field engineer. Since then, he has gained 20 years of consulting experience and 4 years leading the corporate water team for a large independent oil company. He has performed in both technical and managerial roles working on projects for municipal, power, nuclear, and agricultural clients in addition to oil and gas operators. Mr. Nichols has been an active member of organizations such as the Society of Petroleum Engineers, National Ground Water Association, South Central Membrane Association, and the American Water Works Association.

EXPERIENCE HIGHLIGHTS

Tetra Tech

Operations and Maintenance – Public Water System, Goldsmith Field Office, Confidential Client, Andrews, Texas. 2020 (ongoing). Project Manager. Mr. Nichols serves as the project manager for the operation, maintenance, and regulatory compliance of a small system utilizing Reverse Osmosis Water Treatment in West Texas. The project team is responsible for operating the plant, maintaining operating records, performing required maintenance and repairs, water quality sampling and all regulatory reporting to TCEQ.

America's Water Infrastructure Act Water System Risk and Resiliency Assessment and Emergency Response Plan, City of Pflugerville Public Works, Pflugerville, Texas. 2020. Project Principal. Mr. Nichols served as Project Principal for this assessment which was designed to determine the water system's vulnerabilities to malevolent acts, natural hazards, and proximity and dependency risks. The Risk and Resilience Assessment met all AWIA requirements and provides the city with documentation to develop the required emergency response plan following the methodology presented I Risk Analysis and management for Critical Asset Management protection (RAMCAP), Standard for Risk and Resilience Management for Water and Wastewater Systems (ANSI/AWWA 2010) as described in the AWWA J100 standard. The assessment was completed for water system mission critical cyber (computers, networks, data, and communications systems) and physical (pipelines, pump stations, treatment facilities, water storage) assets including administrative and operations facilities.

Development of a Water Safety Plan, Confidential Private Client, Multiple Locations. 2020. Project Manager and Project Principal. Mr. Nichols recently completed work on an international project to develop consistent and compliant, safe drinking water practices for an industrial client. This project included performing regulatory reviews for multiple locations within and outside the United States. Highlights of the project include obtaining background information for each facility's water system (sources, treatment equipment and system redundancy), identifying risks associated with raw water supplies, sources of contamination, connections to non-potable supplies, areas of low use or stagnation, inadequately designed facilities, in addition to reviewing record keeping, maintenance, and operating procedures. The deliverables for the project included draft and final Management Plans which summarized available data, identified risks, and provided recommendations for mitigation.

Design and Construction of a Reverse Osmosis Concentrate Management System, Confidential Client, Andrews, Texas. 2020. Project Manager. Mr. Nichols served as project manager for the design and construction of an industrial reuse/concentrate management system for an oil and gas field office located in West Texas. The system has been permitted to allow beneficial use of concentrate generated by an on-site reverse osmosis public drinking water facility. The water will meet numerical effluent limits and specific application and reporting conditions.

Devon Energy

Water Management Coordinator, Multiple Locations. 2014-2018. Led Operations Excellence water team in charge of evaluating and deploying water technologies. Developed best practices, created water management plans, and assisted with technical stakeholder engagement. Served as primary contact for regulatory agencies for a major water supply program. Led workshops for internal and external stakeholders with both technical and nontechnical roles. Gained experience and knowledge related to operations in eight established shale plays and multiple emerging areas.

Education:

MS, Civil Engineering,
University of Illinois, 1997

BS, Civil Engineering, University
of Illinois, 1995

Registrations/Certifications:

Professional Engineer, Texas,
No. 91095, 2003

Class D Water Operator, Texas
WO0046576

Professional Affiliations:

Society of Petroleum Engineers

National Ground Water
Association

American Water Works
Association

Office Location:

Austin, TX

Total Years of Experience:

(05/1997) 24

Years with Tetra Tech:

(08/2018) 3

CH2M HILL

Water Mapping and Data Management Study, Confidential Client, CO. 2014. Senior Technical Consultant. Evaluated water data management practices including types of data collected, methods for data collection, data storage, reporting, and tools developed to manage data. Summarized results for a single play to compare to others around the country during future phases.

Energy Water Initiative Case Study Project, Multiple Locations. 2014. Project Manager. Provided technical assistance to the EWI group in accomplishing multiple objectives. Facilitated information sharing within EWI membership through technical meetings and workshops. Documented details of water management practices during on-site visits. Prepared educational reports summarizing case study experiences for both internal and external audiences.

Frac Focus Study, Confidential Client, Multiple Locations. 2014. Project Manager. Performed an audit on over 200 hydraulic fracturing records for operation areas across the country. Reviewed randomly selected records pulled from the Frac Focus website, FracFocus.org for regulatory compliance based on the state where the work was performed. Documented results of the audit in a final report.

Produced Water Management and Treatment, Confidential Client, Weld County, CO. 2014. Senior Technical Consultant. Identified sustainable and economically viable options for managing produced water from leases in Colorado. Evaluated applicable water treatment technologies. Developed water budgets including planned sources, recycle volumes and disposal volumes. Developed a conceptual design including cost, phasing and schedule required to implement the necessary treatment facilities. Developed a request for proposals (RFP) and evaluated proposals from pre-selected service providers to conduct a year-long pilot test to treat the produced water and confirm the treated water met water quality criteria.

Enterprise Water Management Strategy, Confidential Client, Multiple Locations. 2013. Senior Technical Consultant. Developed enterprise-wide framework to implement water management strategies. Led a series of workshops held at corporate headquarters which included business unit team members from across North America to share experiences, lessons learned, and ideas about how the company should manage water. Provided recommendations for future technical needs and corporate staffing.

Water Management and Stewardship in Oil and Gas Operations, Multiple Locations. 2012. Senior Technical Consultant. Evaluated water management practices and challenges in the upstream unconventional oil and gas industry. Collected publicly available data, research, and other information related to water management in unconventional plays across the United States. Described water use in each lifecycle stage, describing water management practices employed by industry. Summarized existing regulatory framework. Illustrated oil and gas industry water use in context with other industry and societal uses. Demonstrated that industry water investment generates significant societal benefits.

Regional Water Management Plan, Confidential Client, Permian Basin, TX. 2013. Senior Technical Consultant. Developed a strategic plan to meet short- and long-term water needs for planned oil and gas development operations. Reviewed existing and projected water demands and characterized available resources. Identified supply alternatives and relative costs associated with their development. Identified potential risks and risk mitigation strategies. Provided recommendations for immediate and long-term actions.

West Texas Baseline Sampling Plan, Confidential Client, Permian Basin, TX. 2014. Project Manager. Collected data to identify existing water wells in the area. Managed site visits to verify access and logistics, and water sample collection. Supported delivery to the approved laboratory in accordance with company protocols. Developed required documentation and associated reports.

Permitting of Temporary Pit and Water Recycling Activities, Confidential Client, Permian Basin, NM. 2013. Project Manager. Led permitting efforts for a temporary pit and treatment facility to treat produced water for a fracturing pilot test on a future well. The project was initiated based on client's desire to reduce reliance on fresh water in the region and reduce wastewater volumes that would otherwise be injected into Class II injection wells. The produced water had total dissolved solids (TDS) concentrations exceeding 200,000 mg/l. Results of the pilot confirmed that fracturing with this high TDS water is possible.

Upstream Oil and Gas Subject Matter Expert; Gas/Liquid Combustion Water Vapor Generation Study, Multiple Locations. 2014. Senior Technical Consultant. Compared water vapor generated from combustion of natural gas versus combustion of other fossil fuels and biomass. Addressed arguments regarding "removing water from water cycle" in the natural gas production process by quantifying the volume of water produced by combustion of natural gas, as well as

comparing amounts of carbon dioxide (CO₂) emitted per unit of water vapor emitted from combustion of these different fuels. Updated to include water vapor generated from combustion of additional fossil fuels not addressed in the original study. Performed a literature review to determine water consumed during processing of natural gas liquids and refining of crude oil.

Review of Regulatory and Permitting Requirements Applicable to Flowback and Produced Water Treatment, Multiple Locations. 2010. Senior Technical Consultant. Summarized regulatory and permitting requirements and trends pertaining to management and reuse of flowback and produced water. Investigated Arkansas (Fayetteville Shale), Louisiana (Haynesville Shale), and Texas (Barnett, Haynesville, and Eagle Ford Shale). Summarized requirements at federal, state, local levels, as well as interstate and local stakeholder authorities (river authorities and groundwater conservation districts). Developed a convenient matrix with key citations, agency contact information, application requirements, approval times, application costs, and links to forms where available.

Qualitative Risk Assessment for Hydraulic Fracturing Operations in Proximity to San Antonio Water System (SAWS) Regional Carrizo Project, San Antonio Water System, San Antonio, TX. 2012. Senior Technical Consultant. Led the study to qualitatively evaluate potential risk of oil and gas operations near San Antonio Water Systems Regional Carrizo Well Field in Gonzales County, Texas located within Eagle Ford shale play in South Texas. Included evaluation of current and historical well construction and completion practices, pathways through which hydraulic fracturing or reservoir fluids could migrate to fresh aquifers including Carrizo. Investigated existing waste disposal operations and oil production from nearby shallow formation. Provided specific recommendations for baseline sampling and long-term monitoring.

Wellfield Design, San Antonio Water System Regional Carrizo Buckhorn Wellfield, San Antonio Water System, San Antonio, TX. 2012. Project Engineer. Developed well and designs for 9 production wells with maximum pumping rates of 1,200 gpm, averaging approximately 2,000 feet deep. Led mechanical design for production wellheads. Assisted with associated collection and transmission piping designs.

Enhanced Recharge Study, Lower Colorado River Authority, Austin, TX. 2009. Project Engineer. Assisted the Lower Colorado River Authority (LCRA) with concept-level design and cost estimating for enhanced groundwater recharge as part of development of new firm water to meet long-term deficits in agricultural irrigation supplies in the lower basin caused by increasing utilization of existing municipal and industrial water supply permits. Provided infiltration calculations, conceptual design of the proposed infiltration basins and preliminary cost estimates for the required facilities. Supported development of plans for a demonstration project.

Dowell Schlumberger

Well Production and Well Construction Services, Laredo, TX. 1997-1999. Field Engineer. Worked in the oil and gas industry as a field engineer in well production and well construction services departments of Schlumberger-Dowell. Assisted with project planning, execution, and analysis on wells in south Texas between 5,000 and 10,000 feet deep. Many of the high-pressure, high-temperature gas wells in south Texas presented some of the most challenging treatment environments in the world at the time. Supervised cementing crew during cementing operations. Assisted with hydraulic fracturing operations logistics and water quality evaluation

Publications and Presentations

Groundwater Protection Council UIC Conference 2017. Produced Water – Transportation and Logistics Challenges. Ken Nichols, Thomas Herrell/Select Energy Services, Jordan Price/Tetra Technologies, Inc.

Groundwater Protection Council UIC Conference 2016. Devon Energy's 2015 Delaware Basin Water Management Program. Jeff Sawyer/Devon and Ken Nichols/Devon

Society of Petroleum Engineers Oklahoma City Section – Water Management Forum Panelist

Water Management for Shale Plays West 2014. Identifying Viable Water Sourcing Alternatives Beyond Fresh Water. Ken Nichols/CH2M HILL and Lindsay Atkinson/CH2M HILL.

Texas Water 2013. Qualitative Risk Assessment for Hydraulic Fracturing Operations in Proximity to the SAWS Regional Carrizo Project. Adam Eddy/San Antonio Water System and Ken Nichols/CH2M HILL.

2013 National Ground Water Association Annual Summit. Qualitative Risk Assessment for Hydraulic Fracturing Operations in Proximity to the SAWS Regional Carrizo Project. Adam Eddy/San Antonio Water System and Ken Nichols/CH2M HILL.

2012 AWWA Hydraulic Fracturing Work Group Webinar. September 11, 2012. Qualitative Risk Assessment for Hydraulic Fracturing Operations in Proximity to the SAWS Regional Carrizo Project. Adam Eddy/San Antonio Water System and Ken Nichols/CH2M HILL.

2012 WaterReuse Association. Water Reuse and Recycling in the Oil and Gas Industry: Devon's Water Management Success. Fort Worth, Texas. July 20, 2012. Nathan Kuhnert/Devon, Rusty Werline/Devon, Ken Nichols/CH2M HILL.

2012 National Ground Water Association Focus Conference on Midwestern Groundwater Issues. June 26-27, 2012. Columbus, Ohio. What Every Groundwater Professional Should Know about Hydraulic Fracturing. Ken Nichols/CH2M HILL.

2012 National Ground Water Association Focus Conference on Gulf Coast Groundwater Issues. October 16-17, 2012. Baton Rouge, Louisiana. What Every Groundwater Professional Should Know about Hydraulic Fracturing. Ken Nichols/CH2M HILL.

2012 Air and Waste Management Association's 105th Annual Conference. San Antonio, Texas. June 19, 2012. Water Management from Short Term to Sustainable: Strategic Integrated Water Management for Shale Energy Development. Nathan Kuhnert/Devon Energy Production Company, Mark Anderson/CH2M HILL, and Ken Nichols/CH2M HILL.

2012 Oklahoma Water Survey Workshop – Oil and Gas Operations and the Protection of Water Resources. October 25, 2012. Holistic Water Management for Shale Energy Development. Norman, Oklahoma. Nathan Kuhnert/Devon Energy Production Company and Ken Nichols/CH2M HILL.

2012 Texas Water 2012. Fort Worth, Texas. Reaching Out and Drilling Deep—The San Antonio Water System's Regional Carrizo Project. Gary Guy/San Antonio Water System, Adam Eddy/San Antonio Water System, Kenneth Nichols/CH2M HILL, Stephen Bianchetta/CH2M HILL.

2012 Texas Commission on Environmental Quality (TCEQ) Annual Public Drinking Water Conference. TCEQ Requirements for Public Drinking Water Well Construction. Vera Poe/TCEQ, Deborah Helstrom/TCEQ, Ken Nichols/CH2M HILL.

2010 Texas Commission on Environmental Quality (TCEQ) Annual Public Drinking Water Conference. TCEQ Requirements for Public Drinking Water Well Construction. Vera Poe/TCEQ, Deborah Helstrom/TCEQ, Ken Nichols/CH2M HILL.

2010 Ground Water Protection Council (GWPC). Energy Water Symposium: Developing Sustainable New Water Supplies for Natural Gas Development. Kenneth Nichols/CH2M HILL, Bruce Thomas-Benke/CH2M HILL, and Matthew Mantell/Chesapeake Energy.

2010 U.S. Geological Survey (USGS) Options for Controlling Concentrations of Arsenic and Uranium in Public Drinking Water Supplies Seminar. Groundwater Development in Aquifers with Naturally Occurring Arsenic. Kenneth Nichols/CH2M HILL.

2009 National Groundwater Association Expo. Well Design and Construction for Improved Energy Efficiency. Thomas Klein/San Antonio Water System and Ken Nichols/CH2M HILL.

2009 GWPC UIC Conference. Aquifer Storage and Recovery in Kerrville, TX. Ken Nichols P.E./CH2M HILL, Stuart Barron/City of Kerrville, Scott Loveland/City of Kerrville, Grant Terry/City of Kerrville.

2009 Texas Water. Water System Capacity Management using Aquifer Storage and Recovery. Ken Nichols/CH2M HILL and Ed Motley/CH2M HILL.

2008 WestCAS Winter Conference. ASR in Kerrville, Texas. Ken Nichols/CH2M HILL, James Dwyer/CH2M HILL, Stuart Barron/City of Kerrville.

2007 Texas Water: Groundwater Development in Aquifers with Naturally Occurring Arsenic – Well Field Expansion, Norman, Oklahoma. Bryan Mitchell/City of Norman, Candy Staring/CH2M HILL, Matt Mantell/CH2M HILL, Ken Nichols/CH2M HILL.

2006 National Groundwater Association Groundwater Summit. Initial Cycle Testing of an ASR Wellfield to Obtain Baseline Hydraulic Characteristics and Recovery Efficiency. Jeff Haby/San Antonio Water System, Kevin Bral/CH2M HILL, Ken Nichols/CH2M HILL.

Vita of
John R. Dunham

EDUCATION

M.B.A., Columbia University

M.A., Economics, New School for Social Research

B.A., Economics, University of Colorado

Professional Certificate, Transportation and Distribution, New York University

GENERAL EXPERIENCE

Mr. Dunham has worked as a manager and an analyst in both the public and private sectors. He has experience in conducting cost-benefit modeling, industry analysis, economic research, and tax and fiscal analysis. As the chief domestic economist for one of America's 10 largest companies, he developed tax analysis programs, increased cost-center productivity, and created economic research operations. He has presented testimony on economic and technical issues in federal court and before federal and state agencies. In addition, Mr. Dunham has developed financial statements, plans, and pro-forma analysis for two start-up ventures.

2002 Managing Partner, GuerrillaEconomics LLC, New York

Own and operate mid-sized New York City based economics consulting firm. Develop models and messaging tools for industry, government and associations, used to defeat harmful tax legislation in dozens of states. Provided expert commentary for media stories.

2000-2001 Vice President, American Economics Group, Inc., Washington, D.C.

Created New York office for Washington based economics consulting firm. Produced dozens of economic studies related to tax policy and public finance, which were used to win litigation related to internet product sales, and to defeat harmful tax legislation in dozens of states.

Assisted in the development of on-line forecasting products.

1995-2000 Manager of Fiscal Issues (Chief Domestic Economist), Philip Morris Management Corp.

Created economic research operations for the nation's largest consumer products company, producing more than 150 economic and finance studies annually. Developed a tax policy analysis program resulting in millions of dollars in cost savings. Performed financial analysis of corporate legal settlements, including the largest in U.S. history.

1994-1995 Senior Economic Analyst, Port Authority of New York and New Jersey.

Created cost/benefit modeling program. Analyzed capital projects valued at \$1.25 billion. Conducted economic research, including privatization review and economic impact analysis of Port Authority operating divisions.

1991-1994 Manager, Information Systems and Research, Philadelphia Regional Port Authority.

Conducted economic impact studies, cost/benefit analysis, facility analysis, and market assessment studies used in negotiations and affecting \$53 million in capital spending. Prepared expert statistical and

economic research for Port Authority's testimony before Congress, Federal Maritime Commission, Federal Trade Commission, and other federal and state regulatory agencies.

1987-1991 Senior Economist, Statistician, Marketing Representative, City of New York.

Analyzed county's \$32 billion budget. Supervised risk management database and reporting for \$300 billion in liability claims. Developed and managed leases, contracts, and RFPs for Cocoa Port, New York City Passenger Ship Terminal, and Red Hook Container Terminal, increasing cargo volumes by nearly 100 percent.

EXAMPLES OF SPECIFIC EXPERIENCE

Developed agency-wide cost/benefit modeling program for one of the nation's largest public authorities. Conducted regional cost/benefit analysis of more than \$1 billion in capital projects, including the George Washington Bridge, harbor dredging programs, Easy-pass toll collection system, and the John F. Kennedy Airport rail link.

Created economic research operation for the nation's largest consumer products company. This operation produced more than 600 separate studies, economic models, and position papers over five years, and has been recognized by prestigious academic journals.

Developed computerized risk management tracking system for New York City, a self-insured major metropolitan area. This system has helped track and process billions of dollars in claims related to slipping and falling, motor vehicle accidents, and medical malpractice.

Developed and marketed major cocoa receiving center on the East Coast. Facilitated the return of cocoa shipping to New York County with concerted research, development, construction, and marketing effort. Facility became the nation's second largest cocoa transshipment operation.

Performed hundreds of market research, economic impact, and financial analyses for the government, corporate, and nonprofit sectors. Research was used for tort settlements, industrial real estate developments, and legislative actions throughout the country.

TEACHING EXPERIENCE

2010 Adjunct Professor of Economics, St. Francis College, New York
Teach Introductory Microeconomics to undergraduate students.

MISCELLANEOUS

Scholastic honors: Beta Gamma Sigma and Phi Beta Kappa

Member of: Board of Directors, WholeBrain Creativity, Inc.
National Association for Business Economics

SELECTED PUBLICATIONS

"Smoking Laws and their Differential Effects on Restaurants, Bars and Taverns," with Dr. Mike Marlow, Contemporary Economic Policy, July 2000.

“The Effects of Smoking Laws on Seating Allocations of Restaurants, Bars and Taverns,” with Dr. Mike Marlow, Economic Inquiry, January 2000.

“The Unintended Consequences of the Inland Waterway Excise Tax”, Background Paper No. 33, Tax Foundation, February 1, 2000;

“The Creation of Impossible Markets,” with Dr. William Lilley and Larry DeFranco, Business Economics, June, 1998

“Breakbulk Possibilities,” Fiber Market News, 1992

EXPERT TESTIMONY

Brown & Williamson Tobacco Corp. v. Pataki, 320 F.3d 200 (2d. Cir., 2003)

Orange County Choppers, Inc v Olaes Enterprises Inc. d/b/a ODM v Vending Supply Inc. (United States District Court for the Southern District of New York: 2007)

Telebrands Corp., v, Sennits, Llc and Francesca Kuglen, Civil Action 09-1045, (United States District Court, District of New Jersey: 2009)

Edom Laboratories, Inc. v Special Tea Plus inc. et. al, CV-09-5185, (United States District Court for the Eastern District of New York: 2009)

Bruce Morris, Trudy Silver and 5C Cultural Center Inc, v. 702 East 5 Street Housing Development Corporation (Supreme Court of the State of New York, County of New York: 2010)

Erik H. Gordon v Softech International, Inc. and John Does 1-10, 1:2010cv05162, (United States District Court for the Southern district of New York: 2010)

Kamal Ramchandani, d/b/a La Rukico Tailors v. Mohanbhai Ramchandani and Mohan’s Custom Tailors, Inc. (United States District Court for the Southern District of New York: 2011)

Before The Pennsylvania Liquor Control Board, Re: Wegmans’ License Transfer : Williamsport : No. 07-9145; LID No. 57946; License No. R-13137, Wilkes-Barre : No. 07-9147; LID No. 58048; License No. R-14938, Dickson City : No. 07-9148; LID No. 57887; License No. R-14953, State College : No. 07-9144; LID No. 57935; License No. R-11694, Bethlehem : No. 07-9158; LID No. 57990; License No. R-18314, Lower Nazareth : No. 07-9170; LID No. 57985; License No. R-2455 (2008)

Nelson Francoise, as Personal Representative of the Estate of Caroline Francois v. Medical Staffing Network Holdings, Inc. et. al., 07-3535-CA-23 (Circuit Court of the 11th Judicial Circuit in and for Dade County, Florida)

Remeka Harper, Individually and on Behalf of Jairia Hearn, a Minor v Public Health Trust of Miami-Dade County D/B/A Jackson Memorial Hospital, et. al., 14-12405-CA-13 (Circuit Court of the 11th Judicial Circuit in and for Dade County, Florida)

University of Miami, d/b/a University of Miami School of Medicine v. Juanita Ruiz and Miguel Angel Ruiz as parents and natural guardians of Michael A. Ruiz, a minor et. al., SC05-2164, (Supreme Court of the State of Florida)

XIP LLC v. Michael McGraw, Comtech LLC, NSRC, LLC Pacific Technical Solutions Inc. v JK Henderson and Roam Corporation, 328-267268-13 (District Court, 348th Judicial District, Tarrant County, Texas)

BERNAT KOCSIS, Pltf. vs. CLEVELAND CLINIC FLORIDA, etc., et at., Dfts., Case # 18016645, (Broward County Circuit Court, Broward County, Florida)

Kanter Real Estate, LLC v. Department of Environmental Protection, City of Miramar, and Broward County, Florida, 17-5096 (Fla. Dist. Ct. App. 2019)

Regulatory Hearings:

US Department of Treasury, Alcohol and Tobacco Tax and Trade Bureau v. Tantus Tobacco LLC

US Department of Treasury, Alcohol and Tobacco Tax and Trade Bureau v. Good Times USA, LLC

US Department of Treasury, Alcohol and Tobacco Tax and Trade Bureau v. North Carolina Tobacco Manufacturing, LLC

US Department of Treasury, Alcohol and Tobacco Tax and Trade Bureau v. National Tobacco Co, LP

US Department of Treasury, Alcohol and Tobacco Tax and Trade Bureau v. Unitabac, EIRL

Pennsylvania Liquor Control Board, Case No. 09-9033, License Transfer Application, License No.: E-3230, LID: No. 60984, Club Partners Ventures, Inc.

Arbitration City of New York v. Police Benevolent Association

Pennsylvania Liquor Control Board, License Hearings for 5 Wegman's Stores. Decided by Supreme Court of Pennsylvania, MALT BEVERAGES DISTRIBUTORS ASSOCIATION and Tanczos Beverages, Inc., Appellants v. PENNSYLVANIA LIQUOR CONTROL BOARD, Appellee, Wegmans Food Markets, Inc., Intervenor. Malt Beverages Distributors Association, Appellant v. Pennsylvania Liquor Control Board, Appellee, Wegmans Food Markets, Inc., Intervenor. Malt Beverages Distributors Association, Appellant v. Pennsylvania Liquor Control Board, Appellee, Wegmans Food Markets, Inc., Intervenor. Malt Beverage Distributors Association and Beer Super, Inc., Appellants v. Pennsylvania Liquor Control Board, Appellee, Wegmans Food Markets, Inc., Intervenor. Malt Beverages Distributors Association and K.E. Pletcher, Inc., Appellants v. Pennsylvania Liquor Control Board, Appellee. Wegmans Food Markets, Inc., 881 A.2d 37 (Pa. Cmmw. Ct. 2005)

Pennsylvania Liquor Control Board, Weis Markets, Lycoming County

Pennsylvania Liquor Control Board, Weis Markets Berks County

Pennsylvania Liquor Control Board, Giant Eagle, Robinson Township, PA

Pennsylvania Liquor Control Board, Ohio Springs Inc. T/A Sheetz, Shippensburg, PA

Pennsylvania Liquor Control Board, Giant Food Stores, LLC, Springfield, PA

Pennsylvania Liquor Control Board, Davio's Northern Italian Steakhouse, Economic Development License, Upper Marion Township, PA

Anne Arundel County Liquor Board Hearing, New License, A&A WINE & SPIRITS NEW LICENSE – 1415 South Main Chapel Way, Gambrills
k/a A&A Wine & Spirits, LLC October 10, 2017.

**The Western Oil and Natural Gas Industry
2018 Economic Impact Study**

Methodology and Documentation



Prepared for

**Western Energy Alliance
1775 Sherman St., 2700
Denver, CO 80203**

By

**John Dunham & Associates, Inc.
32 Court Street, Suite 207
Brooklyn, New York 11215**

June 19, 2018

The Western Oil and Natural Gas Industry 2018 Economic Impact Study

Executive Summary:

The *Western Oil and Natural Gas Industry 2018 Economic Impact Study* estimates the economic contributions made by the oil and gas exploration and production industry to the U.S. economy in 2018. John Dunham & Associates conducted this research, which was funded by Western Energy Alliance. This work used standard econometric models first developed by the U.S. Forest Service, and now maintained by MIG, Inc. Data came from industry sources, government publications, and Infogroup.

The study defines the Western Energy Industry as those firms involved in the exploration, leasing, drilling, completion, production, field services, and processing segments of the oil and gas industry in 13 western states.¹ The study measures the number of jobs in this sector, the wages paid to employees, the value added and total output.

Industries are linked to each other when one industry buys from another to produce its own products. Each industry in turn makes purchases from a different mix of other industries, and so on. Employees in all industries extend the economic impact when they spend their earnings. Thus, economic activity started by the energy production industry generates output (and jobs) in hundreds of other industries, often in states far removed from the original economic activity. The impact of supplier firms, and the “induced impact” of the re-spending by employees of industry and supplier firms, is calculated using an input/output model of the United States. The study calculates the impact on a national basis, by state, by county and by Congressional district.

The study also estimates taxes paid by the industry and its employees. Federal taxes include industry-specific excise and sales taxes, business and personal income taxes, FICA, and unemployment insurance. State and local tax systems vary widely. Direct taxes include federal as well as state lease payments, royalties and severance taxes. Industry firms pay real estate and personal property taxes, business income taxes, and other business levies that vary in each state and municipality. All entities engaged in business activity generated by the industry pay similar taxes. In addition to these “business and personal taxes,” firms involved in the production of oil and gas resources pay millions of dollars in state severance taxes, as well as lease payments and royalties to both the federal government and state governments. These payments are also documented in this study but are not a direct part of the model.

The Western Oil and Natural Gas Industry is a dynamic part of the U.S. economy, accounting for about \$36.63 billion in output or roughly 0.20 percent of GDP. Western oil and gas producers directly or indirectly employed approximately 169,331 Americans in 2018. These workers earned almost \$13.97 billion in wages and benefits. Members of the industry and their employees paid \$4.27 billion in direct federal, state and local taxes, and nearly \$7.71 billion in production related levies.

Summary Results:

The *Western Oil and Natural Gas Industry 2018 Economic Impact Study* measures the impact of the oil and gas exploration and production sector, as defined by the exploration, leasing, field services, drilling, completion, production, and initial processing of oil and natural gas products in 13 western states, on the entire economy of the United States. The industry contributes about \$36.63 billion in economic output or

¹ Throughout this analysis, the “western states” are defined as: Arizona, Colorado, Idaho, Montana, Nebraska, New Mexico, Nevada, North Dakota, Oregon, South Dakota, Utah, Washington and Wyoming.

0.20 percent of GDP and, through its production and distribution linkages impacts firms in 513 of the 536 sectors of the US economy.²

The oil and gas industry includes not only companies that directly drill for and produce oil and natural gas in the western United States, but the operations of hundreds of companies that manage leaseholds, explore for and quantify oil and gas resources, provide field services, and perform initial on-site natural gas refining operations. This includes major integrated energy firms like Exxon/Mobile and Conoco/Phillips, but also thousands of smaller companies located throughout the region that provide a range of services from well completion, to drilling, to field reclamation. All told, these firms employ 50,635 people in either on-site operations or at their office locations.

The vast majority of these employees are involved in drilling and production activities. These include a wide range of workers, from roughnecks on the wells, to pipefitters, to skilled chemists that complete wells. In addition, thousands of scientists, geologists, engineers and chemists design the wells and determine how and where they will be drilled. We estimate that there are nearly 1,862 firms involved in drilling and production activities in the 13 western states³ that employ nearly 37,783 people.

In addition to these workers, there are thousands of workers employed by other companies that are directly involved in the production of oil and gas. These include nearly 2,329 people working in on-field refining operations that separate usable liquid products from natural gas. Another 7,916 people are involved in field operations including carpenters that set up temporary on-site housing and office facilities, electricians that set up temporary electrical services, and geologists, landscapers and environmental engineers that reclaim drilling sites to their original conditions as well as in people work in companies that are involved in the financial side of oil and gas production – providing financing and leasing services. As many as 2,607 truck drivers, pipefitters, short-distance pipeline installation, and welders, among others, are directly involved in moving water, sand, and produced petroleum products around the oil fields.⁴

Other firms are related to the oil and gas production industry as suppliers. These firms produce and sell a broad range of items including pipe, pump jacks, generators, sand, drill-bits and electronics used in the production process. In addition, supplier firms provide a broad range of services, including personnel services, financial services, engineering services, consulting services environmental services, or even transportation services. Finally, a number of people are employed in government enterprises responsible for the regulation of the oil and gas industry. All told, we estimate that the Western Oil and Natural Gas industry is responsible for 32,627 supplier jobs with these firms generating about \$6.84 billion in economic activity.

This economic analysis of the oil and gas production industry also takes additional linkages into account. While it is inappropriate to claim that suppliers to the supplier firms are part of the industry being analyzed⁵ the spending by employees of the industry and those of supplier firms whose jobs are directly dependent on oil and natural gas sales and production should surely be included. This spending on everything from housing, to food, to educational services and medical care makes up what is traditionally called the “induced impact” or multiplier effect of the industry. In other words, this spending, and the jobs it creates is induced by the exploration and production of oil and gas in the western states. We estimate

² Based on GDP of \$19.134 trillion. See: *Gross Domestic Product: Second Quarter 2017 (Second Estimate)*, News Release, US Department of Commerce, Bureau of Economic Analysis, February 20, 2018. Economic sectors based on IMPLAN sectors.

³ Physical locations.

⁴ This does not include those truck drivers, railroad workers or pipeline operators involved in the distribution of oil and gas from the fields to off-site refineries or tank farms.

⁵ These firms would more appropriately be considered as part of the supplier firms’ industries.

that the induced impact of the industry is just over \$14.09 billion, and generates 86,069 jobs, for a multiplier of about 0.90.⁶

An important part of an impact analysis is the calculation of the contribution of the industry to the public finances of the community. In the case of the oil and gas industry, the traditional direct taxes paid by the firms and their employees provide over \$4.27 billion in revenues to the federal, state and local governments. In addition to this, producers and leaseholders pay state severance taxes, royalties and lease payments equal to nearly \$7.71 billion.⁷

Table 1 below presents a summary of the total economic impact of the industry in the United States. Summary tables for each state are included in the Output Model, which is discussed in the following section.

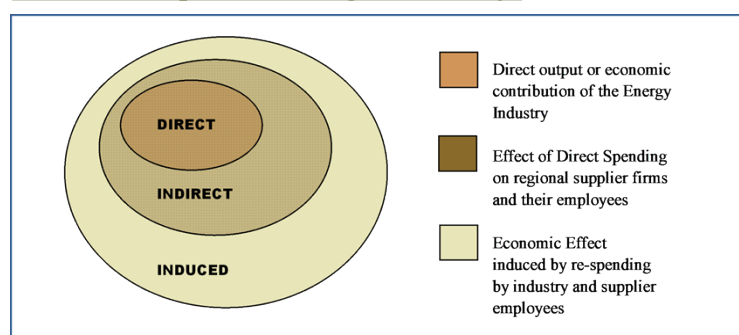
Economic Contribution of the Western Oil and Gas Production Industry: 2018

	Direct	Supplier	Induced	Total
Jobs	50,635	32,627	86,069	169,331
Output	15,698,854,000	\$6,836,564,900	\$14,091,591,400	\$36,627,010,300
Wages	6,909,796,400	\$2,626,742,900	\$4,435,208,300	\$13,971,747,600
Taxes				\$11,979,903,900

Output Model:

John Dunham & Associates, Inc. produced the Economic Impact study for Western Energy Alliance. The analysis consists of a number of parts, each of which will be described in the following sections of this document. These include data, models, calculations and outputs. These components were linked together into an interactive system that allows Western Energy Alliance to examine the links between the various parts of the industry and to produce detailed output documents on an as-needed basis. As such, there is no book – no thick report – outlining the impact of the industry, but rather a system of models and equations that can be continuously queried and updated.

Economic Impact Modeling – Summary:



The Economic Impact Study begins with an accounting of the direct employment in firms involved in oil and gas exploration and production in the 13 states included in the study. The data come from a variety of government and private sources.

It is sometimes mistakenly thought that initial spending accounts for all of the

impact of an economic activity or a product. For example, at first glance it may appear that consumer

⁶ Often economic impact studies present results with very large multipliers – as high as 4 or 5. These studies invariably include the firms supplying the supplier industries as part of the induced impact. John Dunham & Associates believes that this is not an appropriate definition of the induced impact and as such limits this calculation to only the effect of spending by direct and supplier employees.

⁷ This figure is not generated by the economic impact mode. It comes from US Department of Interior, Natural Resources Revenue Data and represents the total, federally recorded revenue of on-shore oil & gas revenues for fiscal year 2017. Available online at: <https://revenuedata.doi.gov/downloads/federal-revenue-by-location/>

expenditures for a product are the sum total of the impact on the local economy. However, one economic activity always leads to a ripple effect whereby other sectors and industries benefit from this initial spending. This inter-industry effect of an economic activity can be assessed using multipliers from regional input-output modeling.

The economic activities of events are linked to other industries in the state and national economies. The activities required to produce a barrel of crude oil for example, from planning the well design, to drilling and completion, to moving the product to a pipeline for distribution generate the direct effects on the economy. Regional (or indirect) impacts occur when these activities require purchases of goods and services such as pipe, cement or electricity from local or regional suppliers. Additional, induced impacts occur when workers involved in direct and indirect activities spend their wages. The ratio between induced economic and direct impact is termed the multiplier. The framework in the chart on the prior page illustrates these linkages.

This method of analysis allows the impact of local production activities to be quantified in terms of final demand, earnings, and employment in the states and the nation as a whole.

Once the direct impact of the industry has been calculated, the input-output methodology discussed below is used to calculate the contribution of the supplier sector and of the re-spending in the economy by employees in the industry and its suppliers. This induced impact is the most controversial part of economic impact studies and is often quite inflated. In the case of the Western Energy Alliance model, only the most conservative estimate of the Induced Impact has been used.

Model Description and Data:

This analysis is based on data provided by Infogroup LLC, Western Energy Alliance, and state and federal governments. The analysis utilizes the IMPLAN Model in order to quantify the economic impact of the Western Oil and Natural Gas industry on the economy of the United States.⁸ The model adopts an accounting framework through which the relationships between different inputs and outputs across industries and sectors are computed. This model can show the impact of a given economic decision – such as a factory opening or operating a sports facility – on a pre-defined, geographic region. It is based on the national income accounts generated by the US Department of Commerce, Bureau of Economic Analysis (BEA).⁹

Every economic impact analysis begins with a description of the industry being examined. In the case of the Western Energy Alliance model, the industry is defined as the exploration, leasing, drilling and completion of wells, production, initial natural gas refining, and remediation of oil and gas fields in the western United States.

The IMPLAN Group model is designed to run based on the input of specific direct economic factors. It uses a detailed methodology (see IMPLAN Methodology section) to generate estimates of the other direct impacts, tax impacts, and supplier and induced impacts based on these entries. In the case of the Western Energy Alliance Economic Impact Model, direct employment in the industry is a base starting point for the analysis. Direct employment is based directly on data provided to John Dunham & Associates by Infogroup LLC as of February 5, 2018, and data from Western Energy Alliance. Infogroup data is

⁸ The model uses 2016 input/output accounts.

⁹ RIMS II is a product developed by the U.S. Department of Commerce, Bureau of Economic Analysis as a policy and economic decision analysis tool. IMPLAN was originally developed by the US Forest Service, the Federal Emergency Management Agency and the Bureau of Land Management. It was converted to a user-friendly model by the Minnesota IMPLAN Group in 1993.

recognized nationally as a premier source of micro industry data.¹⁰ In addition, for cases where employment data for Western Energy Alliance member firms were available, Infogroup employment figures were replaced with those from the Alliance.

Direct jobs are then mapped to their physical locations using a geographic analysis package.¹¹ In addition, the location of all active and licensed oil and gas wells in each of the states was gathered from the various state licensing agencies and departments of natural resources. These well locations were also mapped to their geographic location (longitude and latitude) using the Maptitude software. Since most of these direct jobs ended up being geographically located in the Denver, Colorado region, it was determined that many of the companies were reporting their employment at their headquarters or other physical location, even though most manpower worked at individual field locations. In order to account for this discrepancy, jobs were reallocated based three factors; the number of active and producing oil and gas wells identified in each state,¹² the reported total production of oil in each state,¹³ and the employment in each state as defined by this study. The number of production, drilling, and well support service jobs were allocated across states based on the percentage of wells and rigs, production, and employment located in each. In total, these adjustments led to a reallocation of jobs away from Colorado and Wyoming primarily to North Dakota and Montana. In addition, data were cross-referenced with the number of active wells in each state to ensure that they were within reasonable bounds.

Once the initial direct employment figures have been established, they are entered into a model linked to the IMPLAN database. The IMPLAN data are used to generate estimates of direct wages and output. Wages are derived from data from the U.S. Department of Labor's ES-202 reports that are used by IMPLAN to provide annual average wage and salary establishment counts, employment counts and payrolls at the county level. Since this data only covers payroll employees, it is modified to add information on independent workers, agricultural employees, construction workers, and certain government employees. Data are then adjusted to account for counties where non-disclosure rules apply. Wage data include not only cash wages, but health and life insurance payments, retirement payments and other non-cash compensation. It includes all income paid to workers by employers.

Total output is the value of production by industry in a given state. It is estimated by IMPLAN from sources similar to those used by the BEA in its RIMS II series. Where no Census or government surveys are available, IMPLAN uses models such as the Bureau of Labor Statistics Growth model to estimate the missing output.

The model also includes information on income received by the Federal, state and local governments, and produces estimates for the following taxes at the Federal level: corporate income payroll, personal income, estate, gift, and excise taxes; customs duties; and fines, fees, etc. State and local tax revenues include estimates of: corporate profits, property, sales, severance, estate and gift and personal income taxes; licenses and fees; and certain payroll taxes.

¹⁰ Infogroup, is the leading provider of business and consumer data for the top search engines and leading in-car navigation systems in North America. Infogroup gathers data from a variety of sources by sourcing, refining, matching, appending, filtering, and delivering the best quality data. The company verifies its data at the rate of almost 100,000 phone calls per day to ensure absolute accuracy.

¹¹ Maptitude GIS, *Caplier*, 2016.

¹² Data was gathered from each of the 13 state's natural resource department, which hold records on state permits and well registries, and includes oil and gas wells that are licensed, drilled, and producing. More detailed information on sources by state can be obtained directly from JDA.

¹³ Crude Oil Production, US Department of Energy, Energy Information Administration, April 18, 2018, at: www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbbl_m.htm.

Data on severance taxes, lease payments and royalties to the federal government and governments of the 13 states is calculated separately from the impact model. In this case, data were gathered directly from the states and the US Department of Interior and aggregated for inclusion into the model.¹⁴

While IMPLAN is used to calculate the state level impacts, Infogroup data provide the basis for Congressional and state legislative district level estimates as well as county level impacts. Publicly available data at the county and Congressional district level is limited by disclosure restrictions, especially for smaller sectors of the economy like can manufacturing. Our model therefore uses actual physical location data provided by Infogroup in order to allocate jobs – and the resulting economic activity – by physical address or when that is not available, zip code. For zip codes entirely contained in a single geographic boundary, jobs are allocated based on the percentage of total sector jobs in each zip code. For zip codes that are broken by geographic boundary, allocations are based on the percentage of total jobs physically located in each segment of the zip code. Physical locations are based on either actual address of the facility, or the zip code of the facility, with facilities placed randomly throughout the zip code area. In the case of direct production, drilling, and well support and services employment, the geographic allocations are based on an average of the physical location of jobs as reported to Infogroup, and the physical location of active wells.¹⁵

All supplier and indirect jobs are allocated based on the percentage of a state’s employment in that sector in each of the districts. Again, these percentages are based on Infogroup data.

IMPLAN Methodology:¹⁶

Francoise Quesnay one of the fathers of modern economics, first developed the analytical concept of inter-industry relationships in 1758. The concept was actualized into input-output analysis by Wassily Leontief during the Second World War, an accomplishment for which he received the 1973 Nobel Prize in Economics.

Input-Output analysis is an econometric technique used to examine the relationships within an economy. It captures all monetary market transactions for consumption in a given period and for a specific geography. The IMPLAN model uses data from many different sources – as published government data series, unpublished data, sets of relationships, ratios, or as estimates. The Minnesota IMPLAN group gathers this data, converts it into a consistent format, and estimates the missing components.

There are three different levels of data generally available in the United States: Federal, state and county. Most of the detailed data is available at the county level, and as such there are many issues with disclosure, especially in the case of smaller industries. IMPLAN overcomes these disclosure problems by combining a large number of datasets and by estimating those variables that are not found from any of them. The data is then converted into national input-output matrices (Use, Make, By-products, Absorption and Market Shares) as well as national tables for deflators, regional purchase coefficients and margins.

The IMPLAN Make matrix represents the production of commodities by industry. The Bureau of Economic Analysis (BEA) Benchmark I/O Study of the US Make Table forms the bases of the IMPLAN model. The Benchmark Make Table is updated to current year prices, and rearranged into the IMPLAN

¹⁴ These tax data were gathered in June of 2018 by John Dunham & Associates staff using both agency websites, and through telephone calls to officials and the various agencies. More detailed information on sources by state can be obtained directly from JDA.

¹⁵ While this does not matter in Montana, North Dakota and Wyoming since these states have a single Congressional District, it did lead to significant reallocations in Colorado, Utah, New Mexico and Arizona.

¹⁶ This section is paraphrased from IMPLAN Professional: Users Guide, Analysis Guide, Data Guide, Version 2.0, MIG, Inc., June 2000.

sector format. The IMPLAN Use matrix is based on estimates of final demand, value-added by sector and total industry and commodity output data as provided by government statistics or estimated by IMPLAN. The BEA Benchmark Use Table is then bridged to the IMPLAN sectors. Once the re-sectoring is complete, the Use Tables can be updated based on the other data and model calculations of interstate and international trade.

In the IMPLAN model, as with any input-output framework, all expenditures are in terms of producer prices. This allocates all expenditures to the industries that produce goods and services. As a result, all data not received in producer prices is converted using margins which are derived from the BEA Input-Output model. Margins represent the difference between producer and consumer prices. As such, the margins for any good add to one. If, for example, 10 percent of the consumer, in this case the well-head, price of oil is from the purchase of steel, then the steel margin would be 0.1.

Deflators, which account for relative price changes during different time periods, are derived from the Bureau of Labor Statistics (BLS) Growth Model. The 224 sector BLS model is mapped to the 536 sectors of the IMPLAN model. Where data are missing, deflators from BEA's Survey of Current Businesses are used.

Finally, one of the most important parts of the IMPLAN model, the Regional Purchase Coefficients (RPCs) must be derived. IMPLAN is derived from a national model, which represents the "average" condition for a particular industry. Since national production functions do not necessarily represent particular regional differences, adjustments need to be made. Regional trade flows are estimated based on the Multi-Regional Input-Output Accounts, a cross-sectional database with consistent cross interstate trade flows developed in 1977. These data are updated and bridged to the 536 sector IMPLAN model.

Once the databases and matrices are created, they go through an extensive validation process. IMPLAN builds separate state and county models and evaluates them, checking to ensure that no ratios are outside of recognized bounds. The final datasets and matrices are not released before extensive testing takes place.

Data and Model:

This analysis is based on a model of the oil and natural gas production industry in 13 western states, which was developed for the Western Energy Alliance by John Dunham and Associates (JDA), a New York City-based economic consulting firm. It is based on a wide range of data sources and assumptions, each of which impacts the final results. JDA has strived to ensure that the assumptions are as cautious as possible leading to what is likely a low estimate of the overall cost of the proposed rule. Each of these assumptions, along with the data used in the development of the models, is detailed below:

Average Drilling Costs: are estimated based on data derived from the U.S. Department of Commerce, Bureau of Economic Analysis as compiled by IMPLAN Inc. in 2014. These data come from the Input/Output accounts of the United States and provide detailed information on the input costs for oil and gas well drilling, including wages, capital costs and leasing costs, as well as costs for various materials and services used in the drilling and completion of oil and gas wells. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas at the wellhead in each state. Annual average prices and production volumes by state are gathered from the US Department of Energy.¹ Costs are divided into well development stages, broadly ‘exploration, leasing and permitting’ and ‘drilling and completion’. Input and labor cost divisions are based on input commodity and service costs, with about 63 percent of the drilling/completion cost assumed to be for drilling and the rest for completion.²

Production Costs: Are derived from the IMPLAN model. These data present detailed figures on the input costs for oil and gas production, including wages, capital costs and leasing costs, as well as costs for various materials and services used in the exploration/leasing/permitting, production, infrastructure development and reclamation of oil and gas plays. The figures used in this model are based on the average cost per dollar of output (basically sales) multiplied by the estimated sale of oil and natural gas at the wellhead in each state as of 2016, which are the latest data available. Annual average prices and production volumes by state are gathered from the US Department of Energy.³

Anticipated Revenues: Are based on data from the US Department of Energy. Revenues are simply equal to the annualized price of either oil or natural gas at the wellhead (by state) multiplied by annual production.⁴ Revenues over the life of a well cannot be derived simply by dividing total revenues by the number of producing wells and multiplying by the expected life. This is because oil and gas wells tend to have either a hyperbolic or an exponentially declining production trend. Based on discussions with industry personnel, a well will generally not be drilled and put into production unless it can recoup at least the direct drilling and completion costs in the first year after completion.

¹ See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

² The model is based on average costs and revenues. These can vary greatly by play, product and individual well.

³ See for example: *Domestic Crude Oil First Purchase Prices by Area*, US Department of Energy, Energy Information Administration, at: www.eia.gov/dnav/pet/pet_pri_dfp1_k_a.htm

⁴ Ibid.

The Number of Wells to be Drilled: Estimated based on data from individual state permitting authorities. Each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage in the production process. While complete standardization between the states is not possible, in general it is possible to label a well as "oil" or "gas," and determine its stage of pre-production.

The number of potentially impacted wells on Federal and federally-controlled lands is based on the assumption that about 4,000 APDs are granted each year. In the states being examined, the number averaged about 3,600 per year.⁵

The Number of Producing Wells: Estimated based on data from individual state permitting authorities. Again, each authority uses different methods to identify whether wells are gas or oil (or both) and the wells' stage of production. While complete standardization between the states is not possible, in general it is possible to label a well as "oil" or "gas," and determine its stage of production. Water wells, disposal wells, capped wells, injection wells, and other operations not directly used to extract petroleum are not included.

Modeling The Impact of Restrictions:

Individual cost elements are derived for each of the four cost areas directly impacted by the specific regulation.

Costs for each of these categories are calculated and then entered into the model for each type of well, type of predominant product (oil or natural gas) and specific state. The resulting higher development and production costs reduce the overall level of return of oil and natural gas development in each specific region and for each product type.

The U.S. Energy Information Administration has provided estimates for the cost-per-well incurred by drilling companies.⁶ Unfortunately, cost-per-well estimates are only reported up to 2007, so JDA has estimated 2008 through 2012. JDA's estimates indicate that in 2012 the U.S. nominal cost per crude oil well drilled was around \$3.2 million.

According to the Bureau of Labor Statistics, the average number of production and non-supervisory employees in the oil and gas extraction industry in 2012 was 106,300.⁷ Considering that the cost per well is a function of the number of production and nonsupervisory employees in the oil and gas extraction industry, changes in employment can be used to estimate future costs per well. Based on this model, the demand elasticity for drilling and production equipment is developed using employment levels as a proxy for demand. Based on the available data, the elasticity for oil drilling is almost unitary – about -0.96, so a 10 percent increase in demand will equate to a 9.6 percent increase in prices.

⁵ Based on data for the past 10 years. About 70 percent of all APD's issued by the Bureau of Land Management have been in these four states. In FY 2013, the last year for which data are available, only 2,300 were issued. See: *Number of Drilling Permits Approved by Fiscal Year on Federal Lands*, US Department of the Interior, Bureau of Land Management, November 18, 2013 at: www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html

⁶ *U.S. Nominal Cost per Crude Oil Well Drilled*, U.S. Energy Information Administration, Release date August 29, 2014. Available at: http://www.eia.gov/dnav/ng/hist/e_ertwo_xwwn_nus_mdwa.htm

⁷ *Employment, Hours, and Earnings from the Current Employment Statistics survey (National.)* Bureau of Labor Statistics, September 2, 2014. Available: see http://data.bls.gov/timeseries/CEU1021100006?data_tool=Xgtable

Based on these changes, the models are recalibrated to calculate changes to the “average well” and to remove marginal production to a point where overall market resets to the original return percentage. In some cases costs are adjusted to reflect how they are applied. For example, permitting costs for Federal permits are considerably higher than those on fee and state lands.

The resulting change in the number of wells that would remain profitable (in percentage terms) is used as a proxy for the percent of new wells that would be not drilled under the restrictive GrSG regulations. The percentage change is assumed to be linearly related to the impact change.



Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

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EPA-452/R-15-002, August 2015

**Regulatory Impact Analysis of the Proposed Emission Standards for New and
Modified Sources in the Oil and Natural Gas Sector**

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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1 EXECUTIVE SUMMARY

1.1 Background

The action analyzed in this regulatory impact analysis (RIA) proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category.

The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.

The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are proposing both methane and VOC standards for several emission sources not currently covered by the NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, pneumatic pumps). In addition, we are proposing methane standards for certain emission sources that are currently regulated for VOC (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). However, we do not expect any incremental benefits or costs as a result from regulating methane for currently regulated VOC sources.

With respect to certain equipment that are used across the source category, the current NSPS regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The proposed amendments would establish methane standards for these equipment across the source category and extend the current VOC standards to the remaining unregulated equipment. Lastly, amendments to the current NSPS are being proposed that improve several aspects of the current standards related to implementation. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and

natural gas sector and related amendments. Except for these implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

As part of the regulatory process, the EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed \$100 million annually. The EPA estimates the proposed NSPS will have costs that exceed \$100 million, so the Agency has prepared an RIA. This RIA includes an economic impact analysis and an analysis of the climate, health, and welfare impacts anticipated from the proposed NSPS.¹ We also estimate potential impacts of the proposed rule on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using 3 and 7 percent discount rates.

This analysis estimates regulatory impacts for the analysis years of 2020 and 2025, which spans a period of six years. The analysis of 2020 is assumed to represent the first year the full suite of proposed standards is in effect and thus represents a single year of potential impacts. We estimate impacts in 2025 to illustrate how new and modified sources accumulate over time under the proposed NSPS. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2020 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically-fractured oil wells, capture methane and VOC emissions that otherwise would be vented to the atmosphere. The averted methane emissions can be directed into natural gas production streams and sold. The revenues derived from natural gas recovery are expected to offset a portion of the engineering costs of implementing the NSPS. In this RIA, we present results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

¹ The analysis in this draft RIA constitutes the economic assessment required by CAA section 317. In the EPA's judgment, the assessment is as extensive as practicable taking into account the EPA's time, resources, and other duties and authorities.

The baseline used for the impacts analysis of our NSPS takes into account emissions reductions conducted pursuant to state regulations covering the relevant operations. More detailed discussion on the derivation of the baseline is presented in Section 3 of this RIA.

1.2 Market Failure

Many regulations are promulgated to correct market failures, which lead to a suboptimal allocation of resources within the free market. Air quality and pollution control regulations address “negative externalities” whereby the market does not internalize the full opportunity cost of production borne by society as public goods such as air quality are unpriced.

Greenhouse Gas (GHG) and VOC emissions impose costs on society, such as negative climate, health, and welfare impacts that are not reflected in the market price of the goods produced through the polluting process. For this regulatory action the goods produced, processed, transported, or stored are crude oil, natural gas, and other hydrocarbon products. These social costs associated with the climate, health, and welfare impacts are referred to as negative externalities. If an oil and natural gas firm pollutes the atmosphere while extracting, processing, transporting, or storing the commodities, this cost will be borne not by the polluting firm but by society as a whole. The market price of the products will fail to incorporate the full opportunity cost to society of producing the products. All else equal, given this externality, the quantity of oil and natural gas produced in a free market will not be at the socially optimal level. More oil and natural gas will be produced than would occur if the power producers had to account for the full opportunity cost of production including the negative externality. Consequently, absent a regulation on emissions, the marginal social cost of the last units of oil and natural gas produced will exceed its marginal social benefit.

1.3 Regulatory Options Analyzed in this RIA

In this RIA, we examine three broad regulatory options.² Table 1-1 shows the emissions

² See Chapter 3 for a detailed discussion of the comparative impacts of the regulatory options. The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions (RECs) in combination with combustion. This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately \$70 million per year lower cost.

sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. Option 1 was selected for co-proposal.

Table 1-1 Emissions Sources and Controls Evaluated at Proposal for the NSPS

Emissions Point	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions and Recompletions				
Hydraulically Fractured Development Oil Wells	REC / Combustion	X	X	X
Hydraulically Fractured Wildcat and Delineation Oil Wells	Combustion	X	X	X
Fugitive Emissions				
Well Pads	Monitoring and Maintenance	Annual	Semiannual	Quarterly
Gathering and Boosting Stations	Monitoring and Maintenance	Semiannual	Semiannual	Quarterly
Transmission Compressor Stations	Monitoring and Maintenance	Semiannual	Semiannual	Quarterly
Pneumatic Pumps				
Well Pads	Route to control	X	X	X
Gathering and Boosting Stations	Route to control	X	X	X
Transmission and Storage Compressor Stations	Route to control	X	X	X
Pneumatic Controllers -				
Natural Gas Transmission and Storage Stations	Emissions limit	X	X	X
Reciprocating Compressors				
Natural Gas Transmission and Storage Stations	Annual Monitoring and Maintenance	X	X	X
Centrifugal Compressors				
Natural Gas Transmission and Storage Stations	Route to control	X	X	X

The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 also requires fugitive emissions survey and repair programs be

However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

performed semiannually (twice per year) at newly drilled or refractured oil and natural gas well sites, new or modified gathering and boosting stations, and new or modified transmission and storage compressor stations. However, low production well sites are exempt from the well site fugitive requirements. A low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.³ Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this RIA presents a “low” impact case and “high” impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate low production sites, assuming that the fraction of wells meeting the low production criteria in the future will be the same as in 2012 (based on the first month of production data from wells newly completed or modified in 2012). The high impact case includes all forecasted well sites providing a bounding case where no newly completed or modified wells meet the low production criteria. Summary results for option 2, then, are presented as ranges.

Options 1 and 3 differ from the Option 2 with respect to the requirements for fugitive emissions. Meanwhile, the co-proposed Option 1 requires annual monitoring for well sites, including low production sites, while maintaining semiannual requirements for others sites. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program, including low production sites. More frequent surveys result in higher costs, higher emissions reductions, and increased natural gas recovery over the co-proposed Option 2.

1.4 Summary of Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-2 through Table 1-4. Note all dollar estimates are in 2012 dollars:

- **Emissions Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOCs and 310

³ Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

to 400 tons of hazardous air pollutants (HAP) in 2020, increasing to 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOCs, and 1,900 to 2,500 tons of HAP prevented in 2025.⁴ The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025.

- Benefits Analysis:** The monetized benefits in this RIA include those from reducing methane emissions, which are valued using the social cost of methane (SC-CH₄).⁵ The EPA estimates that, in 2020, the proposal will yield monetized climate benefits of \$88 million to approximately \$550 million; the mean SC-CH₄ at the 3% discount rate results in an estimate of about \$200 to \$210 million in 2020. In 2025, the EPA estimates monetized climate benefits of \$220 million to approximately \$1.4 billion; the mean SC-CH₄ at the 3% discount rate results in an estimate of about \$460 to \$550 million in 2025.⁶ While we expect that the avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAP, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule.⁷ This is not to imply that there are no health benefits anticipated from the proposed rule; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits.
- Engineering Cost Analysis:** The EPA estimates the total capital cost of the proposed NSPS to be \$170 to \$180 million in 2020 and \$280 to \$330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is \$180 to \$200 million in 2020 and \$370 to \$500 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the proposed NSPS are estimated to be \$150 to \$170 million in 2020 and \$320 to \$420 million in 2025, assuming a wellhead natural gas price of \$4/thousand cubic feet (Mcf). The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, \$1/Mcf change in the wellhead price causes a change in estimated

⁴ Estimates are presented in short tons.

⁵ The social cost of methane (SC-CH₄) is the monetary value of impacts associated with a marginal change in methane emissions in a given year.

⁶ The range of estimates reflects four SC-CH₄ estimates are associated with different discount rates (model average at 2.5, 3 and 5 percent; 95th percentile at 3 percent). See Section 4.3 for a complete discussion.

⁷ Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient PM_{2.5} levels and the health effects associated with PM_{2.5} exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and PM_{2.5} and the highly localized nature of air quality responses associated with VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

engineering compliance costs of about \$8 million in 2020 and \$16 to \$19 million in 2025, given the EPA estimates that about 8 million Mcf in 2020 and 16 to 19 million Mcf of natural gas will be recovered by implementing the NSPS. When using a 3 percent discount rate, the estimate of total annualized engineering costs of the proposed NSPS is \$200 million in 2020 and \$490 million in 2025, or \$150 to \$170 million in 2020 and \$310 to \$420 million in 2025, when estimated revenues from additional natural gas are included.⁸

- Energy System Impacts Analysis:** The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system.⁹ We estimate that natural gas and crude oil production levels remains essentially unchanged in 2020, while slight declines are estimated for 2025 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about \$0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.
- Small Entity Analyses:** To understand the potential impact of the proposed rule of small entities the EPA conducted a screening analysis of the potential impacts by estimating the ratio of potential compliance costs to firm sales (i.e. a cost-to-sales test). Based on the results of this screening analysis, the EPA concluded it is not able to certify that the proposed rule will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE). As a result, the EPA initiated a Small Business Advisory Review panel and completed an Initial Regulatory Flexibility Analysis.
- Employment Impacts Analysis:** The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment and control activities, as well as the labor associated with new reporting and recordkeeping requirements. We estimated one-time and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The one-time labor requirement to comply with the proposed NSPS is estimated at about 50 to 70 FTEs in 2020 and in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 470 to 530 FTEs in 2020 and 1,100 to 1,400 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of people

⁸ The choice of discount rate has a small effect on nationwide annualized costs. The compliance costs related to oil well completions and fugitive emissions surveys occur in each year, so the interest rate has little impact on annualized costs for these sources. The annualized costs for pneumatic pumps, compressors, and pneumatic controllers are sensitive to interest rate, but these constitute a relatively small part of the total compliance cost estimates for the proposal.

⁹ The EPA only modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 1-2 presents the summary results for co-proposed Option 1, Table 1-3 presents summary results for the co-proposed Option 2, and Table 1-4 presents summary results for Option 3. The summary results for Option 2 reflects the range from the low impacts to high impacts case with respect the well site fugitive emissions requirements.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$200 million	\$470 million
Total Costs ²	\$150 million	\$310 million
Net Benefits ³	\$43 million	\$160 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM _{2.5} and ozone exposure from 120,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 310 tons of HAP reduced	Health effects of HAP exposure from 1,900 tons of HAP reduced
	Health effects of ozone exposure from 170,000 tons of methane	Health effects of ozone exposure from 340,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$89 million to \$530 million in 2020 and \$220 million to \$1,200 million in 2025 for the proposed option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 3.8 million metric tons in 2020 and 7.7 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

Table 1-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Proposed Option) in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$200 to \$210 million	\$460 to \$550 million
Total Costs ²	\$150 to \$170 million	\$320 to \$420 million
Net Benefits ³	\$35 to \$42 million	\$120 to \$150 million
	Non-monetized climate benefits	Non-monetized climate benefits
Non-monetized Benefits	Health effects of PM _{2.5} and ozone exposure from 120,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 170,000 to 180,000 tons of VOC reduced
	Health effects of HAP exposure from 310 to 400 tons of HAP reduced	Health effects of HAP exposure from 1,900 to 2,500 tons of HAP reduced
	Health effects of ozone exposure from 170,000 to 180,000 tons of methane	Health effects of ozone exposure from 340,000 to 400,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$88 million to \$550 million in 2020 and \$250 million to \$1,400 million in 2025 for the proposed option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

Table 1-4 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$220 million	\$640 million
Total Costs ²	\$210 million	\$680 million
Net Benefits ³	\$7.6 million	-\$35 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM _{2.5} and ozone exposure from 130,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 200,000 tons of VOC reduced
	Health effects of HAP exposure from 510 tons of HAP reduced	Health effects of HAP exposure from 3,200 tons of HAP reduced
	Health effects of ozone exposure from 190,000 tons of methane	Health effects of ozone exposure from 470,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$99 million to \$590 million in 2020 and \$300 million to \$1,700 million in 2025 for this more stringent option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 4.2 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

1.5 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small entity impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS require controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2013, the Energy Information Administration (EIA) estimates that about 490,000 producing natural gas wells operated in the U.S. The latest available information from EIA indicates there were about 360,000 producing oil wells in the U.S. as of 2009. Domestic dry natural gas production was 24.3 trillion cubic feet (tcf) in 2013, the highest annual production level in U.S. history. The leading five natural gas producing states are Texas, Pennsylvania, Louisiana, Oklahoma, and Wyoming. Domestic crude oil production in 2013 was 2,716 million barrels (bbl), the highest annual level in the U.S. since 1991. The leading five crude oil producing states are Texas, North Dakota, California, Alaska, and Oklahoma.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the EPA's "Economic Analysis of Air Pollution Regulations: Oil and Natural Gas Production" (1996), the EPA's "Sector Notebook Project: Profile of the Oil and Gas

Extraction Industry” (2000), and the EPA’s “Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry” (2012).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per-unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20° or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 *Natural Gas*

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2 , mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2 . Concentrations of H_2S and CO_2 , along with organic sulfur compounds, vary widely among sour gases. A majority of total onshore natural gas production and nearly all offshore natural gas production is classified as sweet.

2.2.3 *Condensates*

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40° or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 *Other Recovered Hydrocarbons*

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 *Produced Water*

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 *Exploration and Drilling*

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out (“blowing out”). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the

surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as “fracking”) has been performed since the 1940s (U.S. DOE, 2013). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction**, pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary or improved oil recovery**). Finally, in **tertiary extraction or enhanced recovery**, gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2013). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional oil and natural gas resource types relevant for this rule include:

- **Shale Oil and Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2013).
- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2013).
- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling

is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 *Natural Gas Processing*

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S , which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 *Natural Gas Transmission and Distribution*

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 *Domestic Proved Reserves*

Table 2-1 shows crude oil and dry natural gas proved reserves, unproved reserves, and total technically recoverable resources as of 2009. According to EIA¹⁰, these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.
- **Unproved resources:** additional volumes estimated to be technically recoverable without consideration of economics or operating conditions, based on the application of current technology.
- **Total technically recoverable resources:** resources that are producible using current technology without reference to the economic viability of production.

According to EIA, dry natural gas is consumer-grade natural gas. The dry natural gas volumes reported in Table 2-1 reflect the amount of gas remaining after liquefiable portion has been removed from the natural gas, as well as any non-hydrocarbon gases that render the natural gas unmarketable have been removed. The sum of proved reserves and unproved reserves equal the total technically recoverable resources. As seen in Table 2-1, as of 2009, proved domestic crude oil reserves accounted for about 10 percent of the totally technically recoverable crude oil resources.

¹⁰ U.S. Department of Energy, Energy Information Administration, Glossary of Terms
<<http://www.eia.doe.gov/glossary/index.cfm?id=P>> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2009

Region	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion barrels)			
48 States Onshore	14.2	112.6	126.7
48 States Offshore	4.6	50.3	54.8
Alaska	3.6	35.0	38.6
Total U.S.	22.3	197.9	220.2
Dry Natural Gas (trillion cubic feet)			
Conventionally Reservoired Fields	105.5	904.0	1,009.5
48 States Onshore ¹	81.4	369.7	451.1
48 States Offshore	15.0	262.6	277.6
Alaska	9.1	271.7	280.8
Tight Gas, Shale Gas and Coalbed Methane	167.1	1,026.7	1,193.8
Total U.S.	272.5	1,930.7	2,203.3

Source: U.S. Energy Information Administration, **Annual Energy Review 2012**. Totals may not sum due to independent rounding.

¹ Includes associated-dissolved natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).

Proved natural gas reserves accounted for about 12 percent of the total technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas. While the dry natural gas proved reserves in 2009 were estimated at 272.5 tcf, wet natural gas reserves were estimated at 283.9 tcf. Of the 283.9 tcf, 250.5 tcf (about 88 percent) is considered to be wet non-associated natural gas, while 33.3 tcf (about 12 percent) is considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas, according to EIA, is natural gas which occurs in crude oil reservoirs as free natural gas or in solution with crude oil.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2013. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become

economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2013

	Crude Oil and Lease Condensate (million barrels)			Dry Natural Gas (Billion Cubic Feet or bcf)		
	Cumulative Production	Proved Reserves	Proved Ult. Recovery	Cumulative Production	Proved Reserves	Proved Ult. Recovery
1990	158,175	26,254	184,429	744,546	169,346	913,892
1991	160,882	24,682	185,564	762,244	167,062	929,306
1992	163,507	23,745	187,252	780,084	165,015	945,099
1993	166,006	22,957	188,963	798,179	162,415	960,594
1994	168,437	22,457	190,894	817,000	163,837	980,837
1995	170,831	22,351	193,182	835,599	165,146	1,000,745
1996	173,197	22,017	195,214	854,453	166,474	1,020,927
1997	175,552	22,546	198,098	873,355	167,223	1,040,578
1998	177,834	21,034	198,868	892,379	164,041	1,056,420
1999	179,981	21,765	201,746	911,211	167,406	1,078,617
2000	182,112	22,045	204,157	930,393	177,427	1,107,820
2001	184,229	22,446	206,675	950,009	183,460	1,133,469
2002	186,326	22,677	209,003	968,937	186,946	1,155,883
2003	188,388	21,891	210,279	988,036	189,044	1,177,080
2004	190,379	21,371	211,750	1,006,627	192,513	1,199,140
2005	192,270	21,757	214,027	1,024,677	204,385	1,229,062
2006	194,127	20,972	215,099	1,043,181	211,085	1,254,266
2007	195,981	21,317	217,298	1,062,447	237,726	1,300,173
2008	197,811	19,121	216,932	1,082,605	244,656	1,327,261
2009	199,763	20,682	220,445	1,103,229	272,509	1,375,738
2010	201,764	23,267	225,031	1,124,545	304,625	1,429,170
2011	203,825	26,544	230,369	1,147,447	334,067	1,481,514
2012	206,202	30,529	236,731	1,171,480	308,036	1,479,516
2013	208,918	33,371	242,289	1,195,814	338,264	1,534,078

Source: U.S. Energy Information Administration

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 11 percent in the early 1990s to 8 to 10 percent over the

period from 2006 to 2013 for crude oil and from above 11 percent during the 1990s to between 7 and 9 percent from 2006 to 2013 for natural gas.

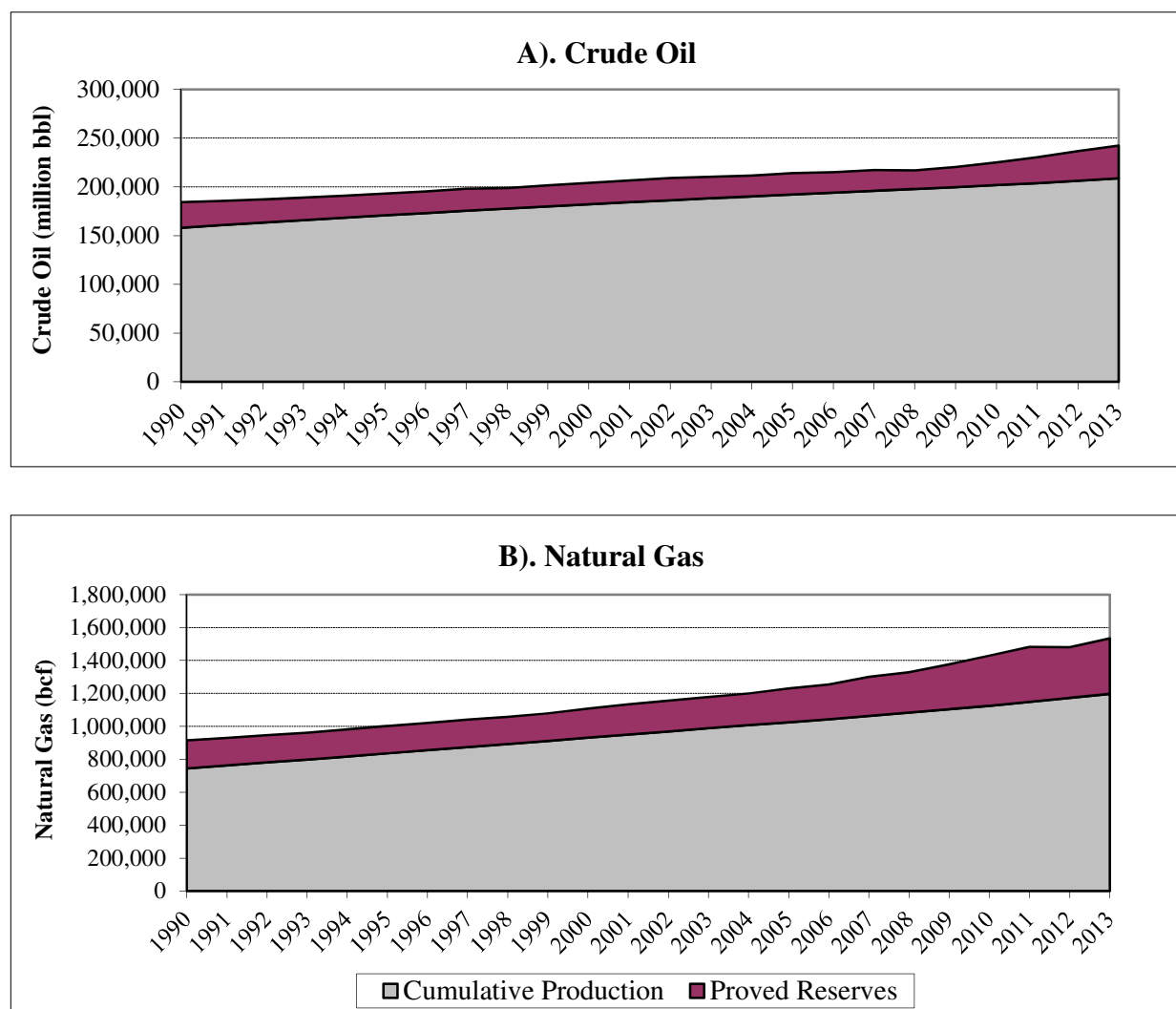


Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2013. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2013

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2013. Five areas currently account for 81 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by North Dakota, U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Pennsylvania, Wyoming, Oklahoma, and West Virginia) account for about 65 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2013

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (% of total)	Dry Natural Gas (% of total)
Alabama	44	1,597	0.1	0.5
Alaska	2,898	7,316	8.7	2.2
Arkansas	40	13,518	0.1	4.0
California	2,876	1,887	8.6	0.6
Colorado	896	22,381	2.7	6.6
Florida	38	15	0.1	0.0
Kansas	372	3,592	1.1	1.1
Kentucky	17	1,663	0.1	0.5
Louisiana	503	20,164	1.5	6.0
Michigan	64	1,807	0.2	0.5
Miscellaneous States	105	2,552	0.3	0.8
Mississippi	223	595	0.7	0.2
Montana	413	575	1.2	0.2
New Mexico	1,171	13,576	3.5	4.0
New York	*	144	*	0.0
North Dakota	5,677	5,420	17.0	1.6
Ohio	42	3,161	0.1	0.9
Oklahoma	1,019	26,873	3.1	7.9
Pennsylvania	15	49,674	0.0	14.7
Texas	10,468	90,349	31.4	26.7
U.S. Federal Offshore	5,137	8,193	15.4	2.4
Utah	613	6,829	1.8	2.0
West Virginia	17	22,765	0.1	6.7
Wyoming	723	33,618	2.2	9.9
Total Proved Reserves	33,371	338,264	100.0	100.0

Source: U.S. Energy Information Administration. Total may not sum due to independent rounding.

* New York crude oil reserves are included in miscellaneous states.

2.4.2 Domestic Production

Domestic oil production was in a state of decline that began in 1970 and continued to a low point in 2008. Since 2008, domestic oil production has recovered to the highest levels since 1991. Table 2-4 shows U.S. production in 2013 at 2,716 million bbl per year.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price, 1990-2013

	Total Production (million barrels)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	US Average First Purchase Price/Barrel (nominal dollars)	US Average First Purchase Price/Barrel (2012 dollars)
1990	2,685	602	4,460	20.03	31.55
1991	2,707	614	4,409	16.54	25.21
1992	2,625	594	4,419	15.99	23.83
1993	2,499	584	4,279	14.25	20.74
1994	2,431	582	4,178	13.19	18.80
1995	2,394	574	4,171	14.62	20.41
1996	2,366	574	4,122	18.46	25.31
1997	2,355	573	4,110	17.23	23.23
1998	2,282	562	4,060	10.87	14.50
1999	2,147	546	3,932	15.56	20.44
2000	2,131	534	3,990	26.72	34.32
2001	2,118	530	3,995	21.84	27.42
2002	2,097	529	3,963	22.51	27.84
2003	2,062	513	4,019	27.56	33.42
2004	1,991	510	3,905	36.77	43.39
2005	1,891	498	3,798	50.28	57.49
2006	1,857	497	3,737	59.69	66.21
2007	1,853	500	3,706	66.52	71.87
2008	1,830	526	3,479	94.04	99.64
2009	1,953	526	3,712	56.35	59.26
2010	2,001	520	3,848	74.71	77.62
2011	2,060	536	3,844	95.73	97.45
2012	2,378	N/A	N/A	94.52	94.52
2013	2,716	N/A	N/A	95.99	94.58

Source: U.S. Energy Information Administration

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased.

Prices adjusted using GDP Implicit Price Deflator.

Average well productivity has also generally decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend.

Annual production of natural gas from natural gas wells has increased more than 8000 bcf from the 1990 to 2013 (Table 2-5). The number of wells producing natural gas has nearly doubled between 1990 and 2011 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2013

	Natural Gas Gross Withdrawals (Billion Cubic Feet)		Natural Gas Well Productivity	
	Total	Dry Gas Production ¹	Producing Wells	Avg. Well Productivity Million Cubic Feet/Year)
1990	21,523	17,810	269,790	66.0
1991	21,750	17,698	276,987	63.9
1992	22,132	17,840	276,014	64.6
1993	22,726	18,095	282,152	64.1
1994	23,581	18,821	291,773	64.5
1995	23,744	18,599	298,541	62.3
1996	24,114	18,854	301,811	62.5
1997	24,213	18,902	310,971	60.8
1998	24,108	19,024	316,929	60.0
1999	23,823	18,832	302,421	62.3
2000	24,174	19,182	341,678	56.1
2001	24,501	19,616	373,304	52.5
2002	23,941	18,928	387,772	48.8
2003	24,119	19,099	393,327	48.6
2004	23,970	18,591	406,147	45.8
2005	23,457	18,051	425,887	42.4
2006	23,535	18,504	440,516	42.0
2007	24,664	19,266	452,945	42.5
2008	25,636	20,159	476,652	42.3
2009	26,057	20,624	493,100	41.8
2010	26,816	21,316	487,627	43.7
2011	28,479	22,902	514,637	44.5
2012	29,542	24,033	482,822	49.8
2013	30,005	24,334	487,286	49.9

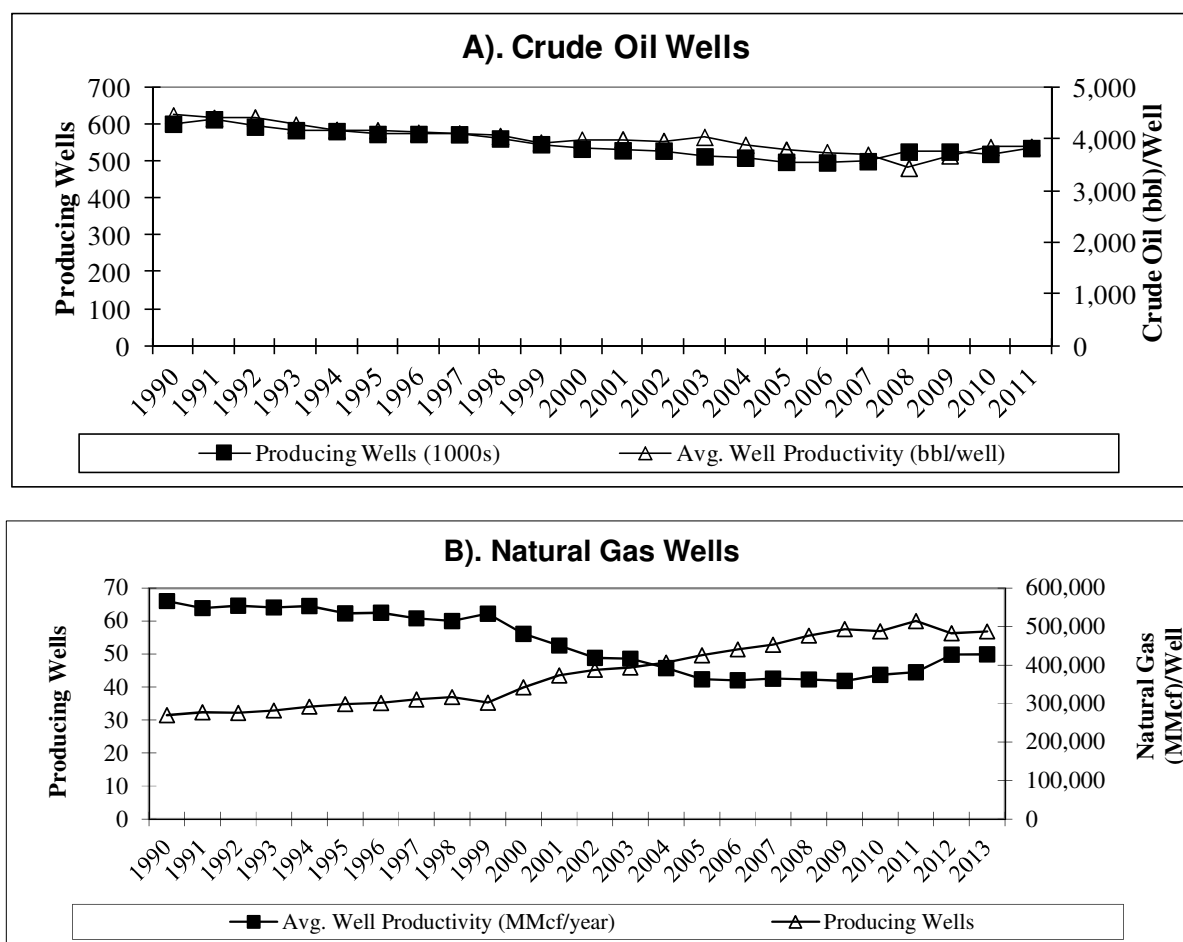


Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2011. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2013.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2010, crude oil well drilling showed significant increases, although the 1992-2004 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2010 period. Like crude oil drilling, 2009 and 2010 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to a peak of 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological

improvements in well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2010

Year	Wells Drilled				Successful Wells (%)	Average Depth (ft)
	Crude Oil	Natural Gas	Dry Holes	Total		
1990	12,445	11,126	8,496	32,067	75	4,881
1991	12,035	9,611	7,882	29,528	75	4,920
1992	9,019	8,305	6,284	23,608	75	5,202
1993	8,764	10,174	6,513	25,451	75	5,442
1994	7,001	9,739	5,515	22,255	77	5,795
1995	7,827	8,454	5,319	21,600	77	5,636
1996	8,760	9,539	5,587	23,886	79	5,617
1997	10,445	11,186	5,955	27,586	79	5,691
1998	6,979	11,127	4,805	22,911	80	5,755
1999	4,314	11,121	3,504	18,939	83	5,090
2000	8,090	17,051	4,146	29,287	86	4,961
2001	8,888	22,072	4,598	35,558	87	5,087
2002	6,775	17,342	3,754	27,871	87	5,232
2003	8,129	20,722	3,982	32,833	88	5,426
2004	8,789	24,186	4,082	37,057	89	5,547
2005	10,779	28,590	4,653	44,022	89	5,508
2006	13,385	32,838	5,206	51,429	90	5,613
2007	13,371	32,719	4,981	51,071	90	6,064
2008	16,633	32,246	5,423	54,302	90	5,964
2009*	11,190	18,088	3,525	32,803	90	6,202
2010*	15,753	16,696	4,162	36,611	89	6,108

Source: U.S. Energy Information Administration

* Average Depth values for 2009-2010 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	1,273,759	21,290	20,258,560	5,063,379	4.00
Federal					
Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	476,693	3,084	736,614	1,025,645	0.72
U.S. Total	1,750,452	24,374	20,995,174	6,089,024	3.45

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states such as Illinois, Missouri, Indiana, and Kansas. Figure 2-3 shows the distribution of produced water management practices in 2007.

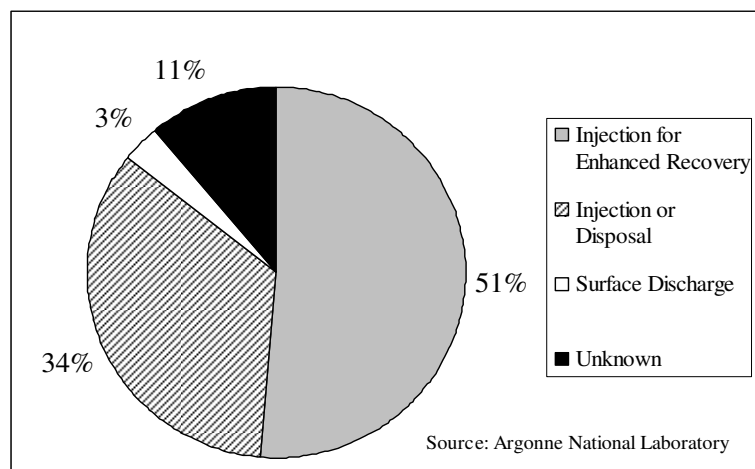


Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2011 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 2010-2013

	Natural Gas Pipelines (miles)				Total
	Distribution mains	Distribution Service	Transmission pipelines	Gathering lines	
2010	1,229,501	872,377	304,775	19,640	2,426,293
2011	1,238,683	881,886	305,036	19,364	2,444,969
2012	1,247,115	892,209	303,333	16,524	2,459,181
2013	1,254,686	894,605	302,827	17,435	2,469,553

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Annual Report Mileage Summary Statistics*, available at <http://phmsa.dot.gov/pipeline/library/data-stats> as of December 29, 2014.

Table 2-8 splits natural gas pipelines into four types: distribution mains, distribution service, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2012 are shown in

Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2012.

Table 2-9 Crude Oil Consumption by Sector, 1990-2012

	Total (million barrels)	Percent of Total			
		Residential and Commercial	Industrial	Transportation Sector	Electric Power
1990	6,178	7.3	25.1	64.3	3.3
1991	6,068	7.3	24.9	64.7	3.2
1992	6,209	7.1	26.1	64.3	2.6
1993	6,277	6.9	25.3	65.0	2.9
1994	6,439	6.6	26.0	64.8	2.6

1995	6,402	6.4	25.7	66.0	1.9
1996	6,627	6.7	26.1	65.2	2.0
1997	6,726	6.3	26.4	65.1	2.2
1998	6,837	5.7	25.4	65.8	3.1
1999	7,053	6.1	25.6	65.5	2.8
2000	6,984	4.6	25.1	67.6	2.6
2001	6,963	4.6	25.1	67.4	2.9
2002	6,990	4.2	25.2	68.3	2.2
2003	7,091	4.6	24.8	67.9	2.7
2004	7,399	4.4	25.3	67.7	2.6
2005	7,530	5.8	24.2	67.3	2.6
2006	7,506	5.0	24.8	68.9	1.4
2007	7,517	5.1	24.1	69.5	1.4
2008	7,095	5.5	23.0	70.4	1.1
2009	6,849	5.5	22.2	71.4	1.0
2010	6,994	5.2	22.8	71.0	0.9
2011	7,013	5.0	23.2	71.1	0.7
2012	6,902	5.0	23.4	71.1	0.5

Source: U.S. Energy Information Administration.

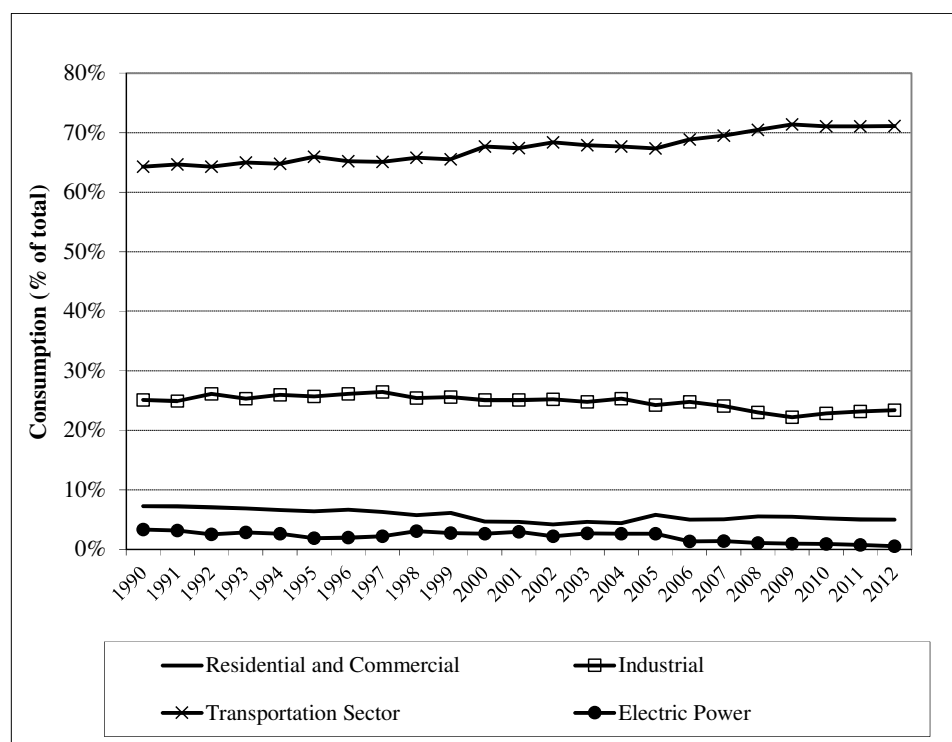


Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2011

Natural gas consumption has increased over the last twenty years. From 1990 to 2012, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2012

	Total (tcf)	Percent of Total				
		Residential	Commercial	Industrial	Electric Power	Transportation
1990	19.93	22.0	13.1	45.3	16.2	3.3
1991	19.56	23.2	13.9	42.8	17.0	3.1
1992	20.23	23.1	13.8	43.1	17.0	2.9
1993	20.80	23.8	13.8	42.7	16.7	3.0
1994	21.27	22.8	13.6	42.0	18.3	3.2
1995	22.25	21.8	13.6	42.4	19.0	3.2
1996	22.67	23.1	14.0	42.9	16.8	3.2
1997	22.88	21.8	14.1	43.0	17.8	3.3
1998	22.32	20.3	13.4	42.9	20.6	2.9
1999	22.43	21.1	13.6	40.9	21.5	2.9
2000	23.31	21.3	13.6	39.9	22.3	2.8
2001	22.21	21.4	13.6	37.9	24.1	2.9
2002	23.02	21.2	13.7	37.5	24.7	3.0
2003	22.03	23.0	14.4	37.5	22.2	2.8
2004	21.99	22.1	14.2	37.9	23.0	2.7
2005	21.62	22.3	13.9	35.7	25.3	2.9
2006	21.37	20.4	13.2	35.9	27.6	2.9
2007	22.78	20.7	13.2	34.6	28.6	2.9
2008	22.95	21.3	13.7	34.4	27.6	3.0
2009	22.89	20.9	13.6	32.5	29.9	3.1
2010	24.06	19.9	12.9	33.7	30.6	3.0
2011	24.38	19.3	12.9	33.7	31.0	3.0
2012	25.64	16.3	11.3	33.4	36.1	3.0

Source: U.S. Energy Information Administration.

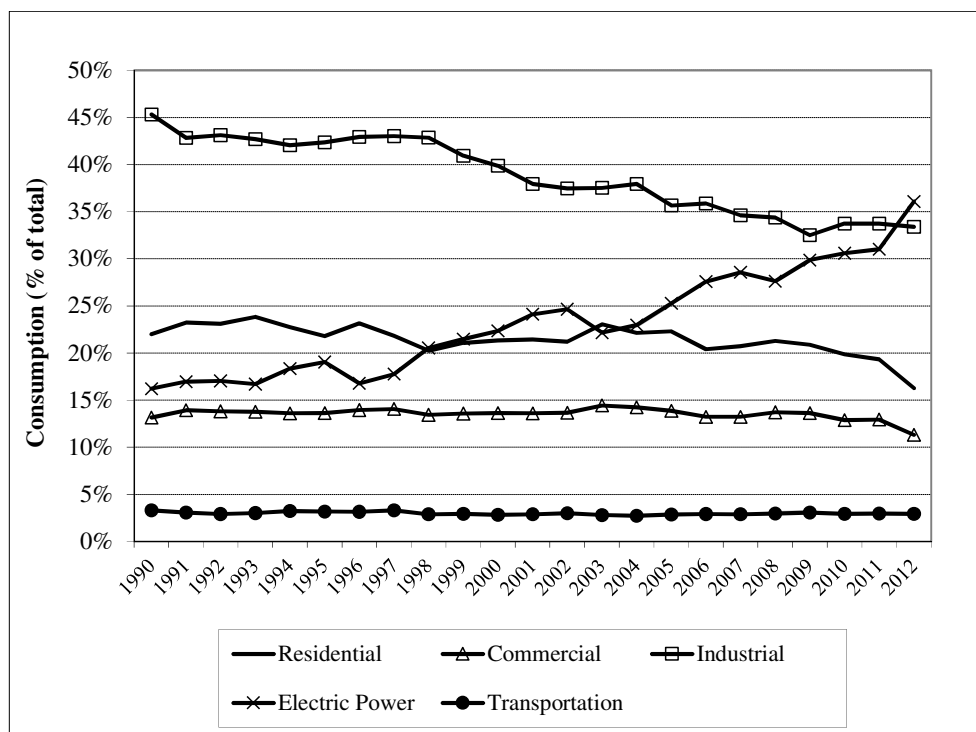


Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2012

2.4.4 International Trade

Until 2006, net trade of crude oil and refined petroleum products increased, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S. (Table 2-11). Since then, however, imports have been declining while exports have been rising, leading to significant declines in net trade of crude oil and petroleum products.

Table 2-11 Total Crude Oil and Petroleum Products Trade (Million Bbl), 1990-2013

	Imports			Exports			Net Imports		
	Crude Oil	Petroleum Products	Total	Crude Oil	Petroleum Products	Total	Crude Oil	Petroleum Products	Total
1990	2,151	775	2,926	40	273	313	2,112	502	2,614
1991	2,111	673	2,784	42	323	365	2,068	350	2,418
1992	2,226	661	2,887	32	315	348	2,194	345	2,539
1993	2,477	669	3,146	36	330	366	2,441	339	2,780
1994	2,578	706	3,284	36	308	344	2,542	398	2,940
1995	2,639	586	3,225	35	312	346	2,604	274	2,878
1996	2,748	721	3,469	40	319	359	2,708	403	3,110
1997	3,002	707	3,709	39	327	366	2,963	380	3,343
1998	3,178	731	3,908	40	305	345	3,137	426	3,564
1999	3,187	774	3,961	43	300	343	3,144	474	3,618
2000	3,320	874	4,194	18	362	381	3,301	512	3,813
2001	3,405	928	4,333	7	347	354	3,398	581	3,979
2002	3,336	872	4,209	3	356	359	3,333	517	3,849
2003	3,528	949	4,477	5	370	375	3,523	579	4,102
2004	3,692	1119	4,811	10	374	384	3,682	745	4,427
2005	3,696	1310	5,006	12	414	425	3,684	896	4,580
2006	3,693	1310	5,003	9	472	481	3,684	838	4,523
2007	3,661	1255	4,916	10	513	523	3,651	742	4,393
2008	3,581	1146	4,727	10	649	659	3,570	497	4,068
2009	3,290	977	4,267	16	723	739	3,274	255	3,528
2010	3,363	942	4,305	15	843	859	3,348	98	3,446
2011	3,261	913	4,174	17	1073	1,090	3,244	-160	3,084
2012	3,121	758	3,879	25	1148	1,173	3,096	-390	2,706
2013	2,821	777	3,598	49	1273	1,322	2,773	-496	2,277

Source: U.S. Energy Information Administration.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 through 2012 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S. consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2013

	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.3
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.4
1998	3,152	159	2,993	13.4
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.8
2004	4,259	854	3,404	15.5
2005	4,341	729	3,612	16.7
2006	4,186	724	3,462	16.2
2007	4,608	822	3,785	16.6
2008	3,984	963	3,021	13.2
2009	3,751	1,072	2,679	11.7
2010	3,741	1,137	2,604	10.8
2011	3,468	1,506	1,962	8.0
2012	3,138	1,619	1,519	5.9
2013	2,883	1,572	1,311	N/A

Source: U.S. Energy Information Administration.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2014 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 7, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2014 Annual Energy Outlook.

Table 2-13 present forecasts of successful wells drilled in the U.S. from 2010 to 2040. Crude oil well forecasts for the lower 48 states show a rise up to the year 2025 then a gradual decline until 2040.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2040

Year	Totals	
	Crude Oil	Natural Gas
2010	19,316	19,056
2011	23,048	14,355
2012	26,749	11,011
2013	25,248	11,507
2014	22,274	14,099
2015	22,706	14,076
2016	22,552	15,004
2017	22,355	15,773
2018	22,421	18,340
2019	22,525	20,188
2020	24,765	20,396
2021	25,017	23,427
2022	25,400	24,945
2023	25,981	24,999
2024	26,917	24,745
2025	27,763	24,831
2026	26,258	25,445
2027	25,830	26,895
2028	25,270	28,341
2029	24,801	29,019
2030	24,310	28,799
2031	23,972	29,681
2032	23,607	31,406
2033	23,283	31,749
2034	23,057	32,882
2035	22,740	33,278
2036	22,494	33,456
2037	22,343	33,536
2038	22,075	33,944
2039	21,911	34,001
2040	21,750	33,656

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2014**.

Meanwhile, show increases for natural gas drilling in the lower 48 states from the present to 2040, more than doubling during this 25-year period.

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and 6 depicts these trends graphically.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2011-2040

	Domestic Production (million bbls)							Lower 48 End of Year Reserves (million bbls)	Lower 48 Average Wellhead Price (2012 dollars per barrel)
	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Other Crude Supply	Net Imports	Total Crude Supply		
2011	2,065	1,336	520	209	97	3,244	7,472	9,161	98.12
2012	2,370	1,679	498	193	32	3,078	7,850	9,018	94.94
2013	2,819	2,132	500	186	85	2,687	8,409	9,360	97.54
2014	3,113	2,396	544	173	59	2,355	8,640	10,054	98.50
2015	3,299	2,534	595	169	0	2,250	8,848	10,224	93.15
2016	3,483	2,581	733	169	0	2,105	9,071	10,957	89.76
2017	3,488	2,598	719	172	0	2,122	9,099	11,073	88.23
2018	3,495	2,607	716	172	0	2,120	9,110	11,228	88.87
2019	3,507	2,620	721	166	0	2,102	9,116	11,410	90.82
2020	3,487	2,632	695	160	0	2,112	9,086	11,599	92.93
2021	3,437	2,632	654	151	0	2,149	9,024	11,652	95.30
2022	3,390	2,624	625	142	0	2,169	8,950	11,721	97.81
2023	3,355	2,610	611	134	0	2,181	8,890	11,830	100.25
2024	3,312	2,594	591	126	0	2,203	8,826	11,898	102.65
2025	3,287	2,570	598	119	0	2,209	8,782	12,050	104.90
2026	3,224	2,517	595	112	0	2,259	8,707	12,192	106.89
2027	3,164	2,474	586	105	0	2,312	8,640	12,237	109.28
2028	3,108	2,429	581	99	0	2,356	8,573	12,299	111.00
2029	3,059	2,381	585	93	0	2,397	8,515	12,367	113.00
2030	3,031	2,330	614	88	0	2,422	8,484	12,564	114.69
2031	2,978	2,284	611	83	0	2,475	8,431	12,585	116.70
2032	2,947	2,237	610	100	0	2,505	8,398	12,612	118.92
2033	2,936	2,195	617	124	0	2,518	8,390	12,650	121.24
2034	2,914	2,155	618	142	0	2,554	8,383	12,642	123.50
2035	2,873	2,114	622	138	0	2,610	8,356	12,622	125.59
2036	2,830	2,068	628	135	0	2,666	8,327	12,618	127.47
2037	2,810	2,028	651	131	0	2,703	8,324	12,687	129.33
2038	2,759	1,987	654	117	0	2,781	8,299	12,656	131.59
2039	2,749	1,949	694	105	0	2,797	8,294	12,859	134.45
2040	2,730	1,909	726	95	0	2,826	8,287	12,938	137.63

Source: U.S. Energy Information Administration, **Annual Energy Outlook, 2014**

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2040, an increase of 25 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 12

percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also shows average wellhead prices increasing more than 100 percent from 2010 to 2040, from \$76.78 per barrel to \$160.38 per barrel in 2011 dollar terms.

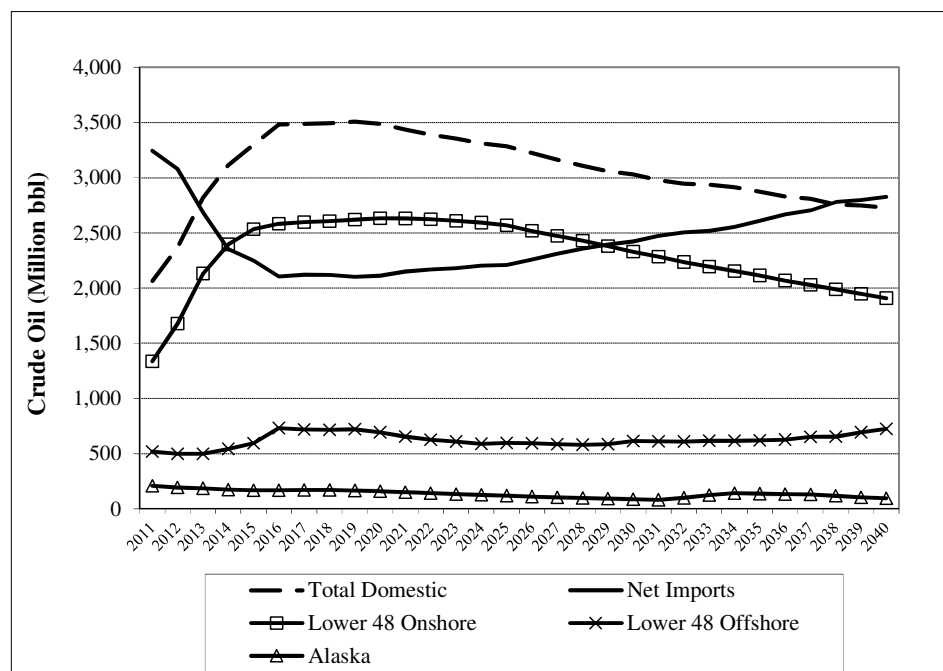


Figure 2-6 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2040

Table 2-15 shows domestic natural gas production is forecast to increase until 2040. Meanwhile, imports of natural gas via pipeline are expected to be eliminated during the forecast period, from 1.68 tcf in 2011 to -2.43 in 2040 tcf. Imports of LNG are also eliminated during the forecast period, from 0.28 tcf in 2011 to -3.37 tcf in 2040. Total supply, then, increases about 33 percent, from 22.55 tcf in 2011 to 37.54 tcf in 2040.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Domestic Production (tcf)		Net Imports (tcf)				
	Dry Gas Productio n	Supplemen tal Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves (tcf)	Average Henry Hub Spot Price (2012 dollars per million Btu)
2011	22.55	0.06	1.68	0.28	24.57	324.6	4.07
2012	24.06	0.06	1.37	0.15	25.64	320.1	2.75
2013	24.19	0.06	1.22	0.12	25.59	329.1	3.60
2014	24.28	0.07	1.21	0.14	25.69	332.5	3.74
2015	24.63	0.06	1.05	0.04	25.78	337.0	3.74
2016	25.68	0.06	0.92	-0.16	26.50	341.8	4.14
2017	26.38	0.06	0.64	-0.61	26.47	344.5	4.40
2018	27.20	0.06	0.45	-1.11	26.61	346.1	4.80
2019	28.19	0.06	0.22	-1.62	26.85	348.6	4.66
2020	29.09	0.06	0.00	-1.93	27.23	352.5	4.38
2021	29.70	0.06	-0.13	-2.17	27.47	354.6	4.67
2022	30.19	0.06	-0.32	-2.17	27.77	358.0	4.82
2023	30.92	0.06	-0.51	-2.37	28.11	362.2	4.96
2024	31.44	0.06	-0.62	-2.57	28.31	365.1	5.12
2025	31.86	0.06	-0.84	-2.57	28.52	368.5	5.23
2026	32.47	0.06	-0.97	-2.77	28.79	372.4	5.36
2027	33.07	0.06	-1.14	-2.97	29.02	375.4	5.49
2028	33.65	0.06	-1.28	-3.17	29.27	378.4	5.59
2029	34.09	0.06	-1.42	-3.35	29.39	380.6	5.78
2030	34.43	0.06	-1.57	-3.37	29.56	382.6	6.03
2031	34.66	0.06	-1.67	-3.37	29.69	385.2	6.17
2032	35.04	0.06	-1.87	-3.37	29.86	387.5	6.36
2033	35.39	0.06	-1.97	-3.37	30.12	389.6	6.59
2034	35.73	0.06	-2.04	-3.37	30.38	391.9	6.74
2035	36.09	0.06	-2.16	-3.37	30.63	393.6	6.92
2036	36.36	0.06	-2.25	-3.37	30.80	394.7	7.18
2037	36.68	0.06	-2.31	-3.37	31.06	397.5	7.23
2038	37.04	0.06	-2.39	-3.37	31.34	399.6	7.26
2039	37.36	0.06	-2.48	-3.37	31.57	401.6	7.42
2040	37.54	0.06	-2.43	-3.37	31.81	402.6	7.65

Source: U.S. Energy Information Administration, Annual Energy Outlook, 2014

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of

about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-7).

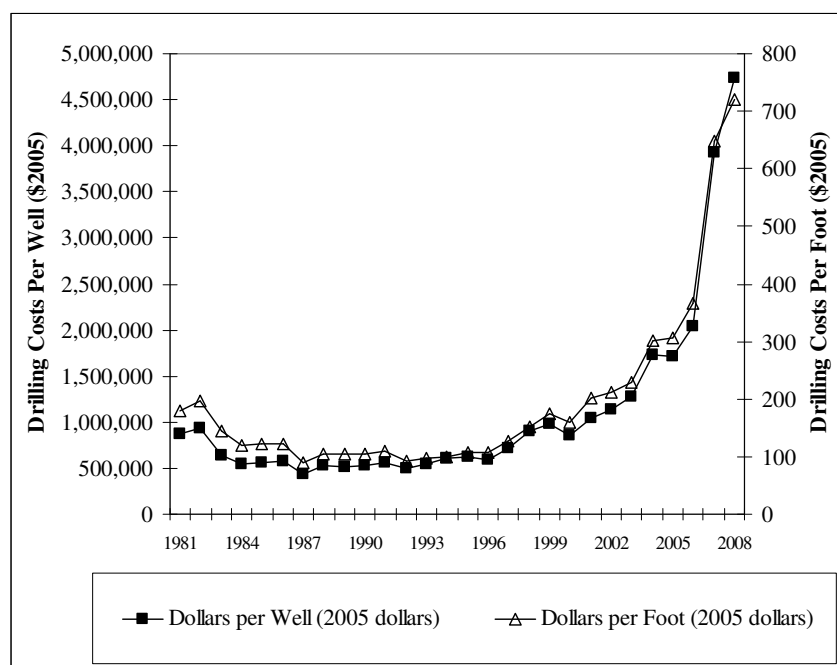


Figure 2-7 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-8 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2009. The costs are reported in 2009 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

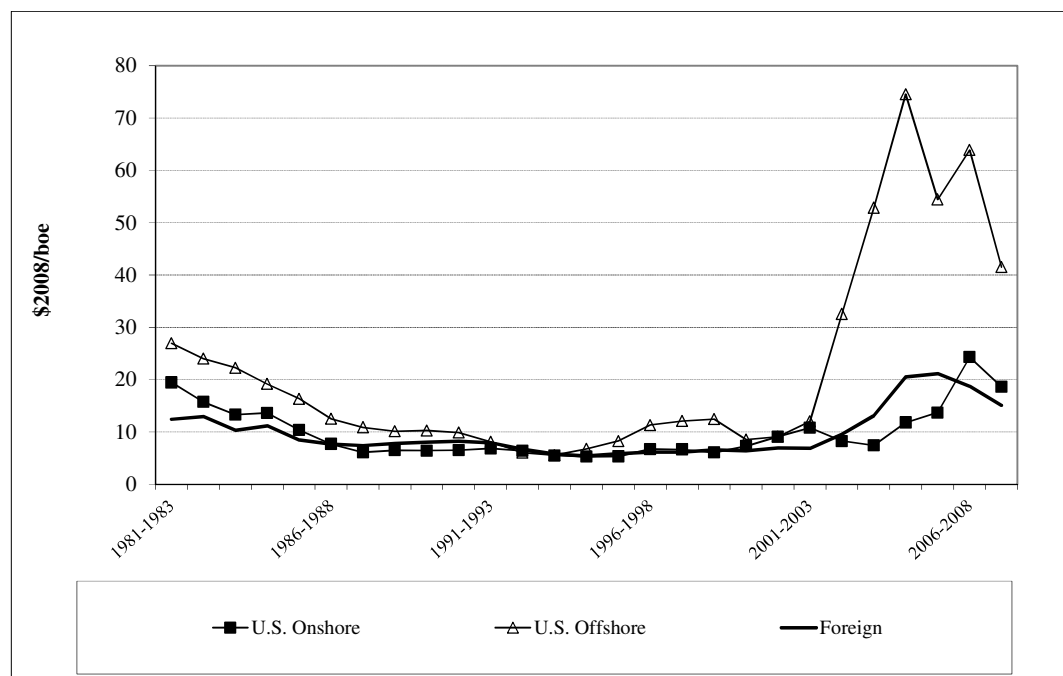


Figure 2-8 Finding Costs for FRS Companies, 1981-2009

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-7 and finding costs in Figure 2-8 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2009 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-9 depicts direct lifting cost trends from 1981 to 2009 for domestic and foreign production.

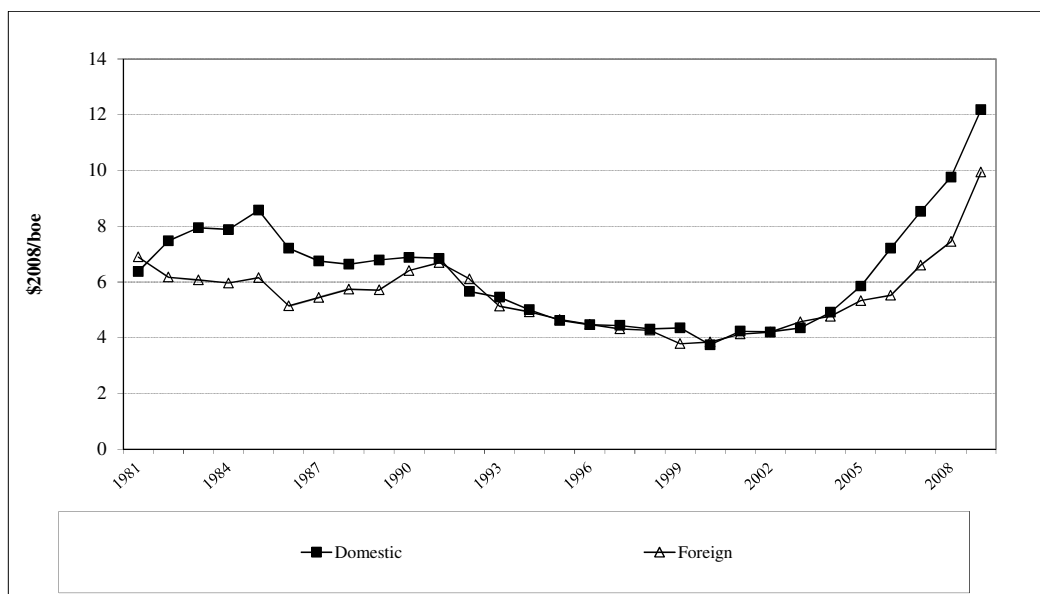


Figure 2-9 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2009 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than \$2 per barrels of oil equivalent from 1981 to 1985, then declined almost \$5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2009, domestic lifting costs increased sharply, just over \$8 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2009.

2.5.3 Operating and Equipment Costs

The EIA report, “Oil and Gas Lease Equipment and Operating Costs 1994 through 2009”¹¹, contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky

¹¹ U.S. Energy Information Administration. “Oil and Gas Lease Equipment and Operating Costs 1994 through 2009.” September 28, 2010.
<http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-10 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

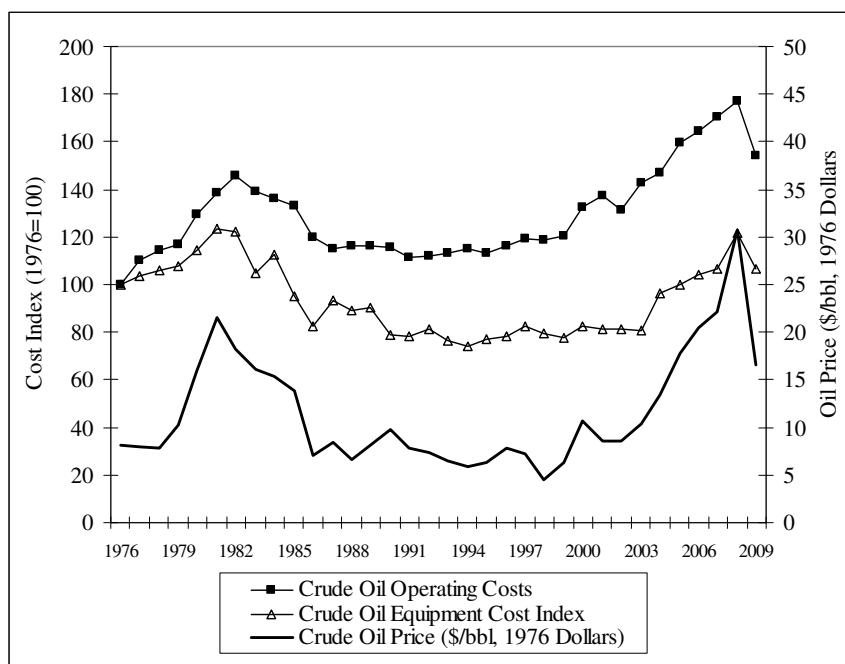


Figure 2-10 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009¹²

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

¹² The last release date for EIA's *Oil and Gas Lease Equipment and Operating Costs* analysis was September 2010. Updates have been discontinued.

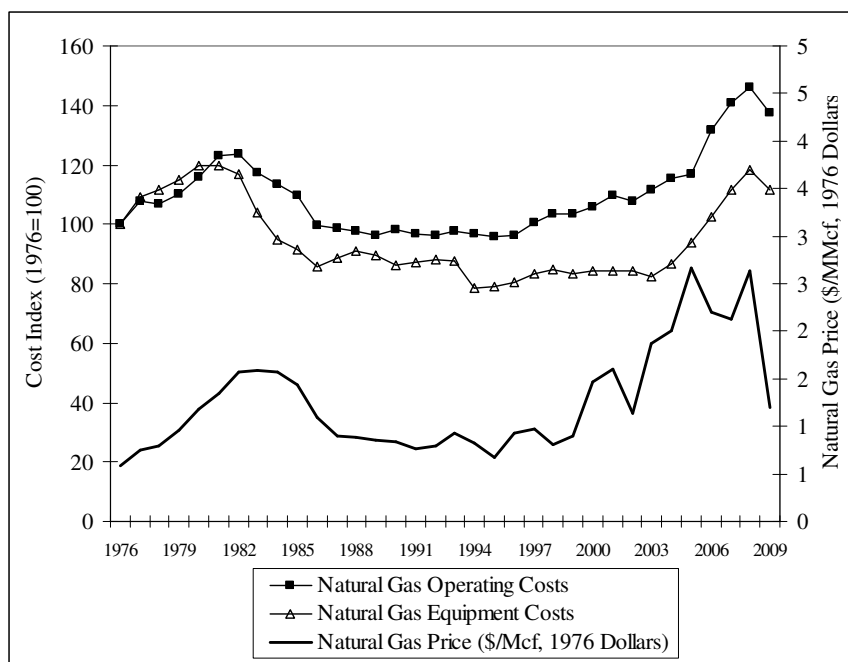


Figure 2-11 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-11 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid-1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected NAICS

As of 2014, there were 6,659 firms within the 211111 and 211112 NAICS codes, of which 6,535 (98 percent) were considered small entities (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for about 60 percent of employment listed under these NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard (Employees or Annual Receipts)	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,436	87	6,523
211112	Natural Gas Liquid Extraction	500	99	37	136
213111	Drilling Oil and Gas Wells	500	1,993	48	2,041
213112	Support Activities for Oil and Gas Operations	\$38.5 million	N/A	N/A	8,119
486210	Pipeline Transportation of Natural Gas	\$27.5 million	N/A	N/A	107
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	45,641	63,313	108,954
211112	Natural Gas Liquid Extraction	500	1,733	8,272	10,005
213111	Drilling Oil and Gas Wells	500	36,663	57,843	94,506
213112	Support Activities for Oil and Gas Operations	\$38.5 million	N/A	N/A	219,827
486210	Pipeline Transportation of Natural Gas	\$27.5 million	N/A	N/A	27,151

Source: U.S. Small Business Administration Office of Advocacy. 2014.

Firm Size Data. <Available at <https://www.sba.gov/advocacy/firm-size-data>> Accessed January 5, 2015.

Note: "N/A" indicates where national counts of small and large firms could not be performed.

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 61 percent of employment. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2013. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 314,000 in 1999, but rebounding to a 2013 peak of 620,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-2013

	Crude Petroleum and Natural Gas Extraction (NAICS 211111)	Natural Gas Liquid Extraction (NAICS 211112)	Drilling of Oil and Natural Gas Wells (NAICS 213111)	Support Activities for Oil and Gas Ops. (NAICS 213112)	Pipeline Trans. of Crude Oil (NAICS 486110)	Pipeline Trans. of Natural Gas (NAICS 486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	350,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539
2010	153,490	4,833	74,491	201,685	8,893	26,708	470,100
2011	164,900	5,835	87,272	241,490	8,959	27,320	535,776
2012	181,473	6,529	92,340	282,447	9,348	27,595	599,732
2013	189,804	6,928	93,261	296,891	10,059	26,981	623,924

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2013 ,
<<http://www.bls.gov/cew/>>

From 1990 to 2013, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2013 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2013 (2012 dollars)

	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	74,475	69,877	44,193	48,010	71,231	64,452	62,245
1991	75,980	69,993	45,593	49,578	72,277	68,228	63,886
1992	80,222	72,285	45,683	51,355	77,941	70,472	67,435
1993	81,214	72,237	47,486	52,649	76,445	70,777	67,734
1994	82,976	74,277	46,717	52,565	79,790	71,804	68,058
1995	85,341	70,873	48,462	53,294	82,717	75,418	69,634
1996	88,319	72,256	51,256	55,400	80,589	80,103	71,727
1997	94,309	83,369	54,754	58,343	82,305	86,858	75,355
1998	97,870	94,427	55,692	60,445	83,028	88,367	77,393
1999	103,235	93,852	57,216	62,756	86,626	99,119	82,969
2000	115,018	117,477	63,787	63,505	84,994	136,907	90,990
2001	116,417	116,513	64,792	64,298	87,363	128,243	89,416
2002	115,314	108,703	65,226	62,847	91,763	96,010	86,240
2003	116,161	118,322	64,095	64,368	91,788	96,109	86,714
2004	127,324	124,374	66,251	65,672	98,381	98,485	90,960
2005	133,920	134,419	74,486	70,753	96,906	95,017	95,030
2006	145,658	140,685	78,047	74,085	96,693	104,055	100,084
2007	143,266	140,329	86,705	76,099	101,516	111,476	101,724
2008	153,155	132,582	86,845	78,432	107,836	105,127	105,011
2009	141,752	131,508	85,854	74,579	106,188	106,598	102,193
2010	152,074	131,980	86,297	77,774	108,855	112,857	106,522
2011	156,035	120,939	91,885	81,441	114,710	116,266	108,863
2012	155,735	136,352	92,266	80,222	120,292	139,127	108,872
2013	153,095	122,787	92,737	80,516	116,215	116,621	107,028

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2013, annual wages per employee <<http://www.bls.gov/cew/>>

Employees in the NAICS 211 codes earn the highest average wages in the oil and natural gas industry, while employees in the NAICS 213 codes have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation.

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal

aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasingly performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the

wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 *Firm-level Information*

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2012, 134 public companies are listed; in 2011 there were 145 firms.¹³ The 2012 list contains four companies that were not on the list in the previous year. Also, 10 other companies listed in 2011 do not appear on the 2012 list as a result of mergers, bankruptcies, or other reasons. Table 2-19 lists selected statistics for the top 20 companies in 2012. The results presented in the table reflect a decline in U.S. natural gas and natural gas liquids prices, weak energy demand growth, and increased capital and operating costs in 2012.

Net income for the top 134 companies fell between 2011 and 2012 from \$114.5 billion to \$91.1 billion. Revenues for these companies fell 1.4 percent from 2011 to 2012. Even though earnings decreased in 2012, strong earnings from 2011 boosted available financial resources and the companies continued to invest. Capital and exploratory spending for the companies in 2012 totaled \$206.5 billion, up 17.1 from 2011.

The total worldwide liquids production for the 134 firms increased 6.85 percent to 2.879 billion bbl, while total worldwide gas production increased 2.4 percent to a total of 17.4 tcf (*Oil and Gas Journal*, September 2, 2013). Meanwhile, the 134 firms on the OGJ list increased both oil and natural gas production and reserves from 2011 to 2012. Domestic production of liquids increased about 19.8 percent from 2011 to 1.437 billion bbl, and natural gas production was up about 6.3 percent. For context, the OGJ150 domestic crude production represents about 49 percent of total domestic production (2.06 billion bbl, according to EIA). The OGJ150 natural gas production represents about 69 percent of total domestic production (28.5 tcf, according to

¹³ Oil and Gas Journal. "OGJ150 Earnings Down as US Production Climbs." September 2, 2013.

EIA).

The OGJ also releases a period report entitled “Worldwide Gas Processing Survey”, which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2012

Rank by Total Assets	Company	Employees	Total Assets (\$Million)	Total Revenue (\$Million)	Net Income (\$Million)	Worldwide Production		US Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	76,900	333,795	482,295	47,681	625	2,992	166	1,518	1,411
2	Chevron Corp.	17,418	232,982	241,909	26,336	536	1,737	151	1,129	1,272
3	ConocoPhillips	16,900	117,144	62,004	8,498	271	1,539	120	916	1,163
4	Occidental Petroleum Corp.	12,300	64,210	24,253	4,598	201	1,129	100	752	1,016
5	Apache Corp.	5,976	60,737	17,078	2,001	145	938	84	685	958
6	Anadarko Petroleum Corp.	5,200	52,589	13,411	2,445	115	916	75	565	951
7	Hess Corp.	14,775	43,441	38,373	2,063	110	839	61	440	826
8	Devon Energy Corp.	5,700	43,326	9,502	-206	103	565	57	407	769
9	Chesapeake Energy Corp.	12,000	41,611	12,316	-594	93	557	49	380	751
10	Marathon Oil Corp.	3,367	35,306	16,221	1582	78	470	45	380	699
11	EOG Resources Inc.	2,650	27,337	11,683	570	49	416	39	313	513
12	Noble Energy Inc.	2,190	17,554	4,223	1027	42	380	34	300	492
13	Murphy Oil Corp.	9,185	17,523	28,626	971	41	322	26	259	468
14	Plains Exploration and Production Co	906	17,298	2,565	343	34	284	25	253	439
15	Pioneer Natural Resources Co.	3,667	13,069	3,228	243	26	259	24	249	367
16	Linn Energy LLC	1,136	11,451	1,774	-387	25	253	24	249	334
17	Denbury Resources Inc.	1,432	11,139	2,456	525	24	249	24	183	315
18	Sandridge Energy Inc.	2,510	9,791	2,731	247	24	249	20	161	297
19	WPX Energy Inc.	1,200	9,456	3,189	-211	22	244	18	160	271
20	Continental Resources Inc.	753	9,140	2,573	416	20	183	18	156	263

Source: Oil and Gas Journal. "OGJ150 Earnings Down as US Production Climbs." September 2, 2013. The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for public oil and natural gas companies with domestic reserves and headquarters in the U.S.

Notes: The source for employment figures is Hoovers, a D&B Company.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
TOTAL FOR TOP 20		264	63,163	40,028
TOTAL FOR ALL COMPANIES		579	73,767	45,472

Source: *Oil and Gas Journal*. “Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009.” June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 162 companies in 2011 (*Oil and Gas Journal*, September 2, 2013). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2012. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 61 percent of the total pipeline mileage and transport about 56 percent of the volume of the industry (Table 2-21). Operating revenues of the

top 20 companies equaled \$12.1 billion, representing 59 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 59 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2012

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Operating Revenue (\$000s)	Net Income (\$000s)
1	Dominion Transmission Inc.	3,687	653,272	903,404	256,010
2	Texas Eastern Transmission LP	9,563	1,747,856	956,536	242,277
3	Florida Gas Transmission Co. LLC	5,336	979,857	775,375	204,968
4	Transcontinental Gas Pipe Line Co. LLC	9,378	3,274,209	1,254,154	194,573
5	Tennessee Gas Pipeline Co.	13,780	2,626,030	1,015,928	190,970
6	Columbia Gas Transmission LLC	9,708	1,305,728	813,185	186,594
7	Natural Gas Pipeline Co of America	8,911	1,511,844	687,366	176,447
8	Southern Natural Gas Co.	7,079	1,005,151	584,828	162,275
9	ETC Tiger Pipeline LLC	196	546,137	279,572	134,934
10	Northern Natural Gas Co.	14,949	928,977	587,768	134,715
11	Panhandle Eastern Pipe Line Co., LP	6,406	581,926	338,787	123,392
12	Texas Gas Transmission LLC	5,880	1,052,070	417,809	106,994
13	Kern River Gas Transmission Co.	1,718	928,206	383,393	105,447
14	Rockies Express Pipeline LLC	1,698	822,587	786,225	103,427
15	CenterPoint Energy Gas Transmission Co., LLC	5,954	1,143,552	437,836	103,290
16	Colorado Interstate Gas Co.	4,253	788,905	397,292	100,902
17	Dominion Cove Point LNG, LP	136	82989	281,517	97,192
18	Gulf South Pipeline Co., LP	6,484	1,115,618	470,149	93,816
19	Northern Border Pipeline Co.	1,408	1,008,857	310,869	89,767
20	Northwest Pipeline GP	3,906	658,161	437,835	87,119
TOTAL FOR TOP 20		120,430	22,761,932	12,119,828	2,895,109
TOTAL FOR ALL COMPANIES		198,279	40,759,824	20,545,763	4,888,125

Source: Oil and Gas Journal. "US Pipeline Operators Sink Revenue Growth into Expansion." September 2, 2013.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies and reports summary information in the publication "The Performance Profiles of Major Energy Producers".¹⁴ This information is used in annual report to Congress, as well as is released to the

¹⁴ The "Performance Profiles of Major Energy Producers 2009" released on February 25, 2011 is the most recent release of this report.

public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated. For 2009, there are 30 companies in the FRS¹⁵ that accounted for 43 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 78 percent of U.S. refining capacity, and 0.3 percent of U.S. electricity net generation (U.S. EIA, 2011). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising until dropping off significantly in 2009. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 and 2009 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

¹⁵ Alenco, Alon USA, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chalmette, Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., Western Refining, WRB Refining LLC, and XTO Energy, Inc.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9
2009	1,136.8	1,085.9	50.8	10.8	18.7	29.5	29.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, 2008, and 2009 for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production was the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent in 1998, 2003, and 2008, with a significant decrease in 2009. Returns to foreign oil and natural gas production rose above domestic production in 2008 and 2009. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies and declined significantly in 2009.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, 2008, and 2009 (percent)

Line of Business	1998	2003	2008	2009
Petroleum	10.8	13.4	12.0	4.5
U.S. Petroleum	10	13.7	8.2	0.4
Oil and Natural Gas Production	12.5	16.5	10.7	3.5
Refining/Marketing	6.6	9.3	2.6	-6.6
Pipelines	6.7	11.5	2.4	4.7
Foreign Petroleum	11.9	13.0	17.8	10.3
Oil and Natural Gas Production	12.5	14.2	16.3	11
Refining/Marketing	10.6	8.0	26.3	5.8
Downstream Natural Gas*	-	8.8	5.1	9.6
Electric Power	-	5.2	181.4	-32
Other Energy	7.1	2.8	-2.1	5.1
Non-energy	10.9	2.4	-5.3	2.8

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2009 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit (\$198 million in 2008)¹⁶ and the effect of the Alternative Minimum Tax (\$34 million in 2008). Income taxes paid to state and local authorities were \$3,060 million in 2008¹³, about 13 percent of the total paid to U.S. authorities.

¹⁶ Data was withheld in 2009 to avoid disclosure.

Table 2-24 Income and Production Taxes, 1990-2009 (Million 2008 Dollars)

Year	US Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507
2009*	-1,655	35,478	-5,988	29,490	-173

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*In 2009, data on the U.S. Federal Investment Tax Credit and U.S. State and Local Income Taxes were withheld to avoid disclosure.

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

2.7 References

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This chapter describes the emissions and engineering cost analysis for the proposed NSPS. The first section discusses the emissions points and control options. The following section describes each step in the emissions and engineering cost analysis and presents overview results. Detailed tables describing the impacts for each source and option can be found at the end of the chapter. We provide reference to the more-detailed Technical Support Document (TSD) prepared by the EPA for the reader interested in a greater level of detail.¹⁷

3.2 Sector Emissions Overview

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural gas industry to provide context for estimated reductions as a result of the proposed rule. Crude oil and natural gas production sector VOC emissions are approximately 2.8 million tons, according to the 2011 EPA National Emissions Inventory (NEI). The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (published April 2015) estimates 2013 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 182 MMt CO₂ Eq. In 2013, total methane emissions from the oil and gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO₂ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2015).

It is important to note that the 2013 GHG emissions estimates do not include methane emissions from hydraulically fractured and re-fractured oil well completions due to lack of available data when the 2013 GHG Inventory estimate was developed. The estimate in this proposed rule includes an adjustment for hydraulically fractured oil wells, and such an adjustment is also being considered as a planned improvement in the 2014 Inventory (to be published April 2016). This adjustment would increase the 2013 Inventory methane estimate by

¹⁷ U.S. EPA. 2015. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards.

about 3 MMt CO₂ Eq. The total methane emissions from Petroleum and Natural Gas Systems based on the 2013 GHG Inventory, adjusted for hydraulically fractured and re-fractured oil well completions, is approximately 185 MMt CO₂ Eq.

3.3 Emissions Points and Pollution Controls assessed in the RIA

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the TSD.

Completions of Hydraulically Fractured and Re-fractured Oil Wells: Well completion activities include multiple steps after the well bore hole has reached the target depth. The highest emissions are from venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. The TSD separately considers developmental wells and exploratory wells. Developmental wells are wells drilled within known boundaries of a proven oil or gas field, while exploratory or “wildcat” wells are wells drilled in areas of new or unknown potential.

The EPA considered the same two techniques that have been proven to reduce emissions from well completions: reduced emissions completions (RECs) and completion combustion. The use of a REC not only reduces emissions but delivers natural gas product that would typically be vented to the sales meter. Completion combustion destroys the organic compounds. Three main technical barriers limit the feasibility of RECs at some wells: proximity of pipelines, pressure of produced gas, and inert gas concentration.

Fugitive Emissions: There are several potential sources of fugitive emissions throughout the oil and natural gas sector. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and pressure or mechanical stresses can also cause components or equipment to leak. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended

lines, pressure relief devices, pump seals, valves or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as gas driven pneumatic controllers or gas driven pneumatic pumps.

The TSD considers fugitive emissions from production well sites, gathering line and boosting stations, and natural gas transmission/storage compressor stations. There are two options for reducing methane and VOC emissions from leaking components: a leak monitoring program based on individual component monitoring using EPA Method 21 for leak detection combined with a leak correction, and a leak monitoring program based on the use of OGI leak detection combined with leak correction. In addition, alternative frequencies for fugitive emissions surveys were considered: annual, semiannual, and quarterly.

Pneumatic controllers: Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These “non-gas driven” pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non-gas-driven controllers are typically used. Continuous bled pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh. The EPA evaluated the impact of replacing high-bleed controllers with low-bleed controllers.

Pneumatic pumps: Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996) and can be a significant source of methane and VOC emissions. Pneumatic chemical and methanol injection

pumps are generally used to pump fairly small volumes of chemicals or methanol into well-bores, surface equipment, and pipelines. Typically, these pumps include plunger pumps with a diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure. They are typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are another type used widely in the onshore oil and gas sector to move larger volumes of liquids per unit of time at lower discharge pressures than chemical and methanol injection pumps. The usage of these pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and circulation of heat trace medium at well sites in cold climates during winter months.

For both of these types of pumps, emissions occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratio's between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump. As discussed in the white papers, we identified several options for reducing methane and VOC emissions: replace natural gas-assisted pump with instrument air pump, replace natural gas-assisted pump with solar-charged direct current pump (solar pumps), replace natural gas-assisted pump with electric pump, and route pneumatic pump emissions to a control device. The EPA evaluated the impact of routing pump emissions to a pre-existing on-site control device.

Centrifugal and Reciprocating Compressors: Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. Centrifugal compressors use either wet or dry seals.

Emissions from compressors occur when natural gas leaks around moving parts in the compressor. In a reciprocating compressor, emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. Over time, during operation of the compressor, the rod packing system becomes worn and will need to be replaced to prevent excessive leaking from the compression cylinder. The potential control options reviewed for

reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includes replacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

Emissions from centrifugal compressors depend on the type of seal used: either “wet”, which use oil circulated at high pressure, or “dry”, which use a thin gap of high pressure gas. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency. Limiting or reducing the emission from the rotating shaft of a centrifugal compressor using a mechanical dry seal system was evaluated. For centrifugal compressors equipped with wet seals, a flare was evaluated as an option for reducing emissions from centrifugal compressors.

3.4 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make to comply with the proposed NSPS. A detailed discussion of the methodology used to estimate cost impacts is presented in the TSD, which is published in the Docket.

The following sections describe each step in the engineering cost analysis. First, representative facilities are established for each source category, including baseline emissions and control options. The regulatory alternatives include different variations of regulatory requirements considered for inclusion in the proposed standards. Then, projections are made of the number of incrementally affected facilities for each type of equipment or facility. National emissions reductions and cost estimates result from multiplying representative factors by the number of affected facilities in each projection year. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted for useful processes or sold. The national cost estimates include estimated revenue from product recovery where applicable. Finally, national-level cost-effectiveness is calculated.

3.4.1 Regulatory Options

For each emissions source, point, and control option, the TSD develops a representative facility. The characteristics of this facility include typical equipment, operating characteristics,

and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. In this RIA, we examine three broad regulatory options.¹⁸ Table 3-1 shows the emissions sources, points, and controls for the three NSPS regulatory options analyzed in this RIA, which we term Option 1, Option 2, and Option 3. Options 1 and 2 were selected for co-proposal.

¹⁸ The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions (RECs) in combination with combustion. This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately \$70 million per year lower cost. However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

Table 3-1 Emissions Sources and Controls Evaluated at Proposal for the NSPS

Emissions Point	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions and Recompletions				
Hydraulically Fractured Development Oil Wells	REC / Combustion	X	X	X
Hydraulically Fractured Wildcat and Delineation Oil Wells	Combustion	X	X	X
Fugitive Emissions				
Well Pads	Monitoring and Maintenance	Annual	Semiannual	Quarterly
Gathering and Boosting Stations	Monitoring and Maintenance	Semiannual	Semiannual	Quarterly
Transmission Compressor Stations	Monitoring and Maintenance	Semiannual	Semiannual	Quarterly
Pneumatic Pumps				
Well Pads	Route to control	X	X	X
Gathering and Boosting Stations	Route to control	X	X	X
Transmission and Storage Compressor Stations	Route to control	X	X	X
Pneumatic Controllers -				
Natural Gas Transmission and Storage Stations	Emissions limit	X	X	X
Reciprocating Compressors				
Natural Gas Transmission and Storage Stations	Annual Monitoring and Maintenance	X	X	X
Centrifugal Compressors				
Natural Gas Transmission and Storage Stations	Route to control	X	X	X

The co-proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. Option 2 also requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at newly drilled or refractured oil and natural gas well sites, new or modified gathering and boosting stations, and new or modified transmission and storage compressor stations. However, low production well sites are exempt from the well site fugitive requirements. A low production site is defined by the average combined oil and natural

gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.¹⁹ Option 2 also requires reductions from centrifugal compressors, reciprocating compressors, pneumatic controllers, and pneumatic pumps throughout the oil and natural gas source category.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this RIA presents a “low” impact case and “high” impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate low production sites, assuming that the fraction of wells meeting the low production criteria in the future will be the same as in 2012 (based on the first month of production data from wells newly completed or modified in 2012). The high impact case includes all forecast well sites providing a bounding case where no newly completed or modified wells meet the low production criteria. Summary results for option 2, then, are presented as ranges.

Options 1 and 3 differ from the Option 2 with respect to the requirements for fugitive emissions. Meanwhile, the co-proposed Option 1 requires annual monitoring for well sites, including low production sites, while maintaining semiannual requirements for others sites. The more stringent Option 3 requires quarterly monitoring for all sites under the fugitive emissions program, including low production sites. More frequent surveys result in higher costs, higher emissions reductions, and increased natural gas recovery over the co-proposed Option 2.

3.4.2 Projection of Incrementally Affected Facilities

The second step in estimating national costs and emissions impacts of the proposed rule is projecting the number of incrementally affected facilities. Incrementally affected facilities are facilities that would be expected to change their emissions control activities as a result of the proposal. Facilities in states with similar state-level requirements are not included within incrementally affected facilities.

The years of analysis are 2020, to represent the first full year of compliance for the proposal, and 2025, to represent impacts of the proposal over a longer period of time. Affected

¹⁹ Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

facilities are facilities which are new or modified since the effective year of the proposal. In 2020 affected facilities are those which are newly established or modified in 2020. Over time more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. In 2025, affected facilities include facilities newly established or modified in 2025, but also facilities which were newly established or modified from 2020 through 2024 and are still operating in 2025.

The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook.

The 2014 Annual Energy Outlook was the most recent projection available at the time that the analysis underlying this RIA was being prepared. However, since then the 2015 Annual Energy Outlook has been released by the U.S. Energy Information Administration. The 2015 AEO reflects that growth in U.S. crude oil production over the last two years, along with the late-2014 drop in global crude oil prices, have altered the economics of the oil market. In comparison to 2014 AEO reference case, the 2015 AEO reference case shows higher crude oil production (in 2025, 18 percent higher in 2015 AEO), slightly lower natural gas production (in 2025, about 4 percent lower in 2015 AEO), lower Brent spot and West Texas Intermediate crude oil prices, and lower total wells drilled in the lower 48 states (in 2025, about 20 percent lower in 2015 AEO). If this RIA were updated to reflect the lower drilling activity in 2015 AEO, then the national costs and emissions reductions of the oil well completions and well site fugitives provisions of the rule would likely be reduced. Costs and emissions reductions per facility would not be affected, however.

We also reviewed state regulations and permitting requirements, which require mitigation measures for many emission sources in the oil and natural gas sector. State regulations in

Colorado and Wyoming both require RECs for hydraulically fractured oil and gas wells. Sources in Colorado, Wyoming, Utah, and Ohio are subject to fugitive emissions requirements. Applicable facilities in these states are not included in the estimates of incrementally affected facilities presented in the RIA, as sources in those states are already subject to similar requirements to the federal standards. A more detailed discussion on the derivation of the baseline for the current proposal is presented for each emissions source in the TSD. The estimated counts of hydraulically-fractured and re-fracture oil well completions also account for the wells anticipated to be excluded from the proposed NSPS requirements because of a gas-to-oil ratio (GOR) of 300 or below.

Table 3-2 Number of Incrementally Affected Sources for the NSPS

Emissions Sources	Incrementally Affected Sources	
	2020	2025 ¹
Hydraulically Fractured and Re-fractured Oil Well Completions	15,000	15,000
Fugitive Emissions ²	14,000 to 22,000	86,000 to 140,000
Pneumatic Pumps	3,000	18,000
Compressors	68	410
Pneumatic Controllers	210	1,300
Total ²	31,000 to 40,000	120,000 to 180,000

¹ In addition to newly affected sources in 2025, incrementally affected sources in 2025 include sources that become affected in the 2020-24 time period and are assumed to be in continued operation in 2025.

² The low end of the range in the fugitive emissions and total rows reflect the number of incrementally affected sources under the low impact co-proposed Option 2, which excludes low production well sites.

Table 3-2 presents the estimates of the number of incrementally affected sources for this proposal after accounting for state regulations as described above. Note that hydraulically fractured and re-fractured oil well completions do not grow significantly from 2020 to 2025, while other sources do. This is a result of completions being a one-time activity in a given year, while other sources are affected and remain affected as they continue to operate, thus these sources accumulate over time. The estimates for that hydraulically fractured and re-fractured oil well completions and fugitive emissions at well sites (a large fraction of the incrementally affected sources under the proposed rule fugitive emissions provisions) include both new and modified sources. The estimates for other sources are based upon projections of new sources alone. While some of these sources, particularly pneumatic pumps and controllers, are likely to be predominantly new sources, the impact estimates may be under-estimated by the under-

represented modified sources. In the preamble to the proposed rule, the EPA solicits comments on these projection methods as well as solicits information that would improve our estimate of the turnover rates or rates of modification of relevant sources, as well as the number of wells on well sites.

3.4.3 Emissions Reductions

Table 3-3 summarizes the national emissions reductions for the evaluated NSPS emissions sources and points for 2020 and 2025. These reductions are estimated by multiplying the unit-level emissions reductions associated with each applicable control and facility type by the number of incrementally affected sources. Table 3-1 summarizes the applicable controls, and Table 3-2 summarizes the affected facilities, aggregating multiple model plant types within each source category (e.g., oil well completions combine development and exploratory wells). The detailed description of emissions controls is provided in the TSD. Please note that all results have been rounded to two significant digits.

Table 3-3 Emissions Reductions for Proposed NSPS Option 2, 2020 and 2025

Source/Emissions Point	Emissions Reductions, 2020			
	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO ₂ Eq.)
Oil Well Completions and Recompletions	140,000	110,000	14	63,100,000
Fugitive Emissions	24,000 to 33,000	6,200 to 8,700	230 to 330	740,000 to 750,000
Pneumatic Pumps	5,400	1,500	57	120,000
Compressors	1,600	43	1	36,000
Pneumatic Controllers	590	16	0	13,000
Total	170,000 to 180,000	120,000	310 to 400	3,800,000 to 4,000,000
Source/Emissions Point	Emissions Reductions, 2025			
	Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO ₂ Eq.)
Oil Well Completions and Recompletions	140,000	120,000	14	3,100,000
Fugitive Emissions	150,000 to 210,000	40,000 to 57,000	1,500 to 2,200	3,500,000 to 4,900,000
Pneumatic Pumps	32,000	9,000	340	740,000
Compressors	9,400	260	8	210,000
Pneumatic Controllers	3,500	97	3	80,000
Total	340,000 to 400,000	170,000 to 180,000	2,200 to 2,500	7,700,000 to 9,000,000

3.4.4 *Product Recovery*

The annualized cost estimates presented below include revenue from additional natural gas recovery in the production and processing segments. Several emission controls for the NSPS capture methane and VOC emissions that otherwise would be vented to the atmosphere. A large proportion of the averted methane emissions can be directed into natural gas production streams and sold. For environmental controls that avert the emission of saleable natural gas, we base the estimated revenues from averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year for the control.

The standards that result in natural gas recovery are: RECs at hydraulically fractured oil wells, fugitive emissions monitoring and repair, rod packing replacement in reciprocating compressors, and low-bleed pneumatic devices. The proposed requirements for completions at exploration and delineation wells, pneumatic pumps, and centrifugal compressors do not result in natural gas recovery. In some of these cases, alternative control strategies do result in natural gas recovery, but these alternative controls were not assumed as part of this analysis. For example, alternatives to routing pneumatic pump emissions to a control device include substituting a solar or electric pump where a gas-driven pump would have otherwise been used.

Table 3-5 summarizes natural gas recovery and revenue included in annualized cost calculations. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid \$4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be \$4.46/Mcf in 2020 and \$5.06/Mcf in 2025. The \$4/Mcf price assumed in this RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

Natural gas recovery at any point in the system provide benefits to the energy system and to the public. However, due to contractual arrangements, transmission and storage companies do not always benefit from lowering the leak rate of their operations because they do not necessarily own the gas, and fixed loss rates are included in long-term contracts. As a result, the EPA excludes revenue from natural gas recovery in estimating compliance costs for the transmission and storage segment. This approach likely overestimates the long-term compliance cost of the

controls.

Table 3-4 Estimated Natural Gas Recovery (Mcf) for Proposed NSPS Option 2 in 2020 and 2025

Source/Emissions Point	2020		2025	
	Gas recovery (Mcf)	Revenue from recovery (millions 2012\$)	Gas recovery (Mcf)	Revenue from recovery (millions 2012\$)
Oil Well Completions and Recompletions	6,200,000	\$25	6,200,000	\$25
Fugitive Emissions	1,400,000 to 1,900,000	\$5.1 to \$7.3	8,900,000 to 12,000,000	\$33 to \$47
Pneumatic Pumps	0	\$0	0	\$0
Compressors	76,000	\$0	450,000	\$0
Pneumatic Controllers	30,000	\$0	180,000	\$0
Total	7,700,000 to 8,200,000	\$30 to \$32	16,000,000 to 19,000,000	\$58 to \$72

As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For the proposed option, a \$1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about \$8 million in 2020 and \$16 to \$19 million in 2025, in 2012 dollars.

3.4.5 Engineering Compliance Costs

Table 3-6 summarizes the capital and annualized costs for the evaluated emissions sources and points. The detailed description of costs estimates is provided in TSD. To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. This approach is mathematically equivalent to establishing an overall, representative project time horizon and annualizing costs after consideration of control options that would need to be replaced periodically within the given time horizon.

Table 3-5 Engineering Compliance Cost Estimates for Proposed NSPS Option 2 in 2020 and 2025 (millions 2012\$)

Source/Emissions Point	Compliance Costs, 2020		Compliance Costs, 2025	
	Capital Costs (2012\$)	Nationwide Annualized Costs (2012\$)	Capital Costs (2012\$)	Nationwide Annualized Costs (2012\$)
Oil Well Completions and Recompletions	\$150	\$120	\$150	\$120
Fugitive Emissions	\$15 to \$22	\$29 to \$47	\$95 to \$140	\$180 to \$290
Pneumatic Pumps	\$5.9	\$0.84	\$36.0	\$5.1
Compressors	\$0.54	\$0.25	\$3.2	\$1.5
Pneumatic Controllers	\$0.048	\$0.0052	\$0.29	\$0.031
Reporting and Recordkeeping	\$0.0	\$1.4	\$0.0	\$4.1
Total	\$170 to \$180	\$150 to \$170	\$280 to \$330	\$320 to \$420

Engineering capital costs were annualized using a 7 percent interest rate. Section 3.4 provides a comparison to using a 3 percent interest rate. Different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section)
- Fugitive emissions monitoring program design: 8 years
- Reciprocating compressors rod packing: 3.8 – 4.4 years
- Centrifugal compressors, pneumatic controllers, and pneumatic pumps: 10 years

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this proposed rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Chapter 5 for more detail). The 2020 reporting and recordkeeping costs in this RIA (\$1.4 million) are based on the first year ICR cost estimates. Meanwhile, we drew upon the first year cost in the ICR cost estimates (\$4.1 million) and applied that cost to 2025 in this RIA.

3.4.6 Cost-Effectiveness

This section summarizes the cost-effectiveness of the proposed standards for each source in 2020 and 2025. The proposed NSPS includes standards for both methane and VOC reductions.

As discussed in the preamble to this action, cost-effectiveness analysis allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the benefit produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a cost-benefits analysis but rather provides a metric of the relative cost to reduction ratios of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure controls a single pollutant. Increasingly, however, air pollution reduction programs require reductions in emissions of multiple pollutants, and in such programs multipollutant controls may be employed. Consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants). This is the case for the current proposal where the EPA is proposing to directly regulate both methane and VOC.

To assign the entire annualized cost to the reduction in emissions of a single pollutant reduced by the multipollutant control option is appropriate when reductions of the other pollutants are considered to cobenefits with no cost. However, under the current proposal, methane and VOCs are both directly regulated; therefore, reductions of each pollutant must be properly considered benefits, not co-benefits, and consideration of only one of the regulated pollutants is not appropriate.

Alternatively, all annualized costs can be allocated to each of the pollutant emission reductions addressed by the multipollutant control option. Unlike the approach above, no emission reduction is treated as a co-benefit; each emission reduction is assessed based on the full cost of the control. However, this approach, which is often used for assessing single-pollutant controls, evaluates emission reduction of each pollutant separately, assuming that each bears the entire cost, and thus inflates the control cost in the multiple of the number of additional pollutants being reduced. This approach therefore over-estimates the cost of obtaining emissions reductions with a multipollutant control as it does not recognize the simultaneity of the reductions achieved by the application of the control option. Another approach allocates the

annualized cost to the sum of the individual pollutant emission reductions addressed by the multipollutant control option. The multipollutant cost-effectiveness approach may be appropriate when each of the pollutant reductions is similar in value or impact. However, in the current proposal, methane and VOC have quite different health and environmental impacts, and therefore summing the pollutants to derive the denominator of the cost-effectiveness equation (i.e., assuming a ton of methane is equivalent in its impacts to a ton of VOC) is inappropriate.

For purposes of this proposal, we have identified and are proposing to use two approaches for considering the cost of reducing emissions from multiple pollutants using one control. One approach is to assign all costs to the emission reduction of one pollutant and zero to all other concurrent reductions; if the cost is reasonable for reducing any of the targeted emissions alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other pollutants because they are being reduced at no additional cost. While this approach assigns all costs to only a portion of the emission reduction, it does not overstate the cost. It also does not require unreasonable assumptions about the equivalency of the impacts between a ton of methane and VOC emission reduction, which is not appropriate as discussed in the option immediately above. In addition, this approach is simple and straight forward in application. If the multipollutant control is cost effective for reducing emissions of either of the targeted pollutant, it is clearly cost effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term a “multipollutant cost-effectiveness” approach, apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled by mass. For example, in this proposal both methane and VOC emissions are reduced in equal proportion by the multipollutant control option. As a result, half of the control costs are allocated to methane, the other half to VOC. This approach similarly does not inflate the control cost nor requires unreasonable assumptions about the equivalency of the impacts between a ton of methane and VOC emission reduction.

We believe that both approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. As such, in our analyses

below, if a device is cost effective under either of these two approaches, we find it to be cost effective. The EPA recognize, however, not all situations where multipollutant controls are applied are the same, and that other approaches, including those described above as inappropriate for this action, might be appropriate in other instances.

Under the single pollutant cost-effectiveness approach, the total national compliance costs are divided by the emissions reductions for methane and VOC separately (Table 3-6). This approach does not account for the combined emissions reductions of both pollutants. We only present the cost-effectiveness for the high impact case for fugitive emissions requirements at well sites. The low impact case would show lower dollar per ton estimates.

Table 3-6 Single Pollutant Approach to Engineering Compliance Cost-Effectiveness Estimates in 2020 and 2025 for Proposed NSPS Option 2 (High Impact Case for Well Site Fugitive Emissions Requirements)

Source/ Emissions Point	Cost-Effectiveness, 2020 (2012\$)			Cost-Effectiveness, 2025 (2012\$)		
	Methane (\$/short ton)	VOC (\$/short ton)	Methane (\$/metric ton CO ₂ Eq.)	Methane (\$/short ton)	VOC (\$/short ton)	Methane (\$/metric ton CO ₂ Eq.)
Oil Well Completions	\$910	\$1,100	\$40	\$900	\$1,100	\$39
Fugitive Emissions	\$1,400	\$5,300	\$62	\$1,400	\$5,100	\$60
Pneumatic Pumps	\$160	\$560	\$7	\$160	\$560	\$7
Compressors	\$160	\$5,600	\$7	\$160	\$5,600	\$7
Pneumatic Controllers	\$9	\$320	\$0	\$9	\$320	\$0
Total	\$980	\$1,400	\$43	\$1,100	\$2,300	\$47

For the multipollutant cost-effectiveness approach, costs are allocated proportionally to methane and VOC reductions based on the percent reduction achieved in each pollutant (Table 3-7). Because the relevant oil and gas controls reduce methane and VOC in equal proportion, 50 percent of costs are allocated to each emission.

Table 3-7 Multipollutant Approach to Engineering Compliance Cost-Effectiveness Estimates for Proposed NSPS Option 2 in 2020 and 2025 (High Impact Case for Well Site Fugitive Emissions Requirements)

Source/ Emissions Point	Cost-Effectiveness, 2020 (2012\$)			Cost-Effectiveness, 2025 (2012\$)		
	Methane (\$/short ton)	VOC (\$/short ton)	Methane (\$/metric ton CO ₂ Eq.)	Methane (\$/short ton)	VOC (\$/short ton)	Methane (\$/metric ton CO ₂ Eq.)
Oil Well Completions	\$450	\$540	\$20	\$450	\$530	\$20
Fugitive Emissions	\$710	\$2,700	\$31	\$680	\$2,500	\$30
Pneumatic Pumps	\$78	\$280	\$3	\$78	\$280	\$3
Compressors	\$78	\$2,800	\$3	\$78	\$2,800	\$3
Pneumatic Controllers	\$5	\$160	\$0	\$5	\$160	\$0
Total	\$490	\$690	\$22	\$530	\$1,200	\$24

3.4.7 Comparison of Regulatory Alternatives

Table 3-8 presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025.²⁰ The requirements between the options vary with respect to the fugitive emissions requirements. Option 1 includes requirements for annual fugitive emissions surveys at well sites but semiannual frequency at other sites, and Option 3 includes requirements for quarterly fugitive emissions surveys, as opposed the semiannual requirement in Options 2. Annual, semiannual, and quarterly fugitive emissions surveys are assumed to result in respective reductions in emissions of 40 percent, 60 percent, and 80 percent, but affect the same number of sources. Natural gas recovery also varies as a result of survey frequency. Variation in natural gas recovery, capital and annualized costs reflect these differences in the number of affected facilities and frequency of fugitive emissions surveys.

²⁰ The EPA also analyzed a variant of proposed Option 2 where only emissions combustion is required for hydraulically fractured and re-fracture oil well completions, rather than require reduced emissions completions in combination with combustion (RECs). This variation of the proposed Option 2 would achieve direct emission reduction that are equivalent to requiring RECs and combustion, but at an approximately \$70 million per year lower cost. However, as explained in Section VIII.F of the preamble to the proposed NSPS, the EPA determined RECs and combustion to be the best system of emissions reduction. Section 4 of the Technical Support Document for the proposal presents the detailed technical analysis of the regulatory options for hydraulically fractured and re-fractured oil well completions.

Table 3-8 Comparison of Regulatory Alternatives

	Regulatory Alternative		
	Option 1	Option 2 (proposed)	Option 3
Impacts in 2020			
Affected Sources	40,000	31,000 to 40,000	40,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	170,000	170,000 to 180,000	190,000
VOC Emissions Reduction (short tons/year)	120,000	120,000	130,000
Natural Gas Recovery (Mcf)	7,700,000	7,700,000 to 8,200,000	8,800,000
Compliance Costs			
Capital Costs (2012\$)	\$180,000,000	\$170,000,000 to \$180,000,000	\$180,000,000
Annualized Costs (2012\$)	\$150,000,000	\$150,000,000 to \$170,000,000	\$210,000,000
Cost-Effectiveness (Single Pollutant Approach) ¹			
Methane (2012\$ / short ton)	\$920	\$920 to \$980	\$1,100
VOC (2012\$ / short ton)	\$1,300	\$1,300 to \$1,400	\$1,700
Cost-Effectiveness (Multipollutant Approach) ¹			
Methane (2012\$ / short ton)	\$460	\$460 to \$490	\$570
VOC (2012\$ / short ton)	\$630	\$640 to \$690	\$840
Impacts in 2025			
Affected Sources	180,000	120,000 to 180,000	180,000
Emissions Reductions			
Methane Emissions Reduction (short tons/year)	340,000	340,000 to 400,000	470,000
VOC Emissions Reduction (short tons/year)	170,000	170,000 to 180,000	200,000
Natural Gas Recovery (Mcf)	16,000,000	16,000,000 to 19,000,000	23,000,000
Compliance Costs			
Capital Costs (2012\$)	\$330,000,000	\$280,000,000 to \$330,000,000	\$330,000,000
Annualized Costs (2012\$)	\$310,000,000	\$320,000,000 to \$420,000,000	\$680,000,000
Cost-Effectiveness (Single Pollutant Approach) ¹			
Methane (2012\$ / short ton)	\$920	\$940 to \$1,100	\$1,400
VOC (2012\$ / short ton)	\$1,900	\$1,900 to \$2,300	\$3,400
Cost-Effectiveness (Multipollutant Approach) ¹			
Methane (2012\$ / short ton)	\$460	\$470 to \$530	\$720
VOC (2012\$ / short ton)	\$940	\$960 to \$1,200	\$1,700

¹ Cost-effectiveness based on high impact case for well site fugitive emissions requirements.

3.4.8 *Capital and Annualized Compliance Costs Compared to Industry-level Capital Expenditures and Revenues*

In order to provide another perspective on the reasonableness of the estimated cost of control as determined in our evaluation of "Best System of Emission Reduction" (BSER) for the proposed standards, we analyzed the total cost of the rule for each type of affected facility under two additional approaches using industry economic data.

First, we compared the total nationwide capitals costs that would be incurred for each type of affected facility to comply with the proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. Capital expenditure data for relevant NAICS codes covered by the rule were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey²¹. For the capital expenditures analysis, we determined the estimated nationwide capital costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide capital costs by the new capital expenditures (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. For example, we used the total estimated capital cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total capital expenditures the NAICS codes that correspond to oil and natural gas production segment. Table 3-9 below summarizes the capital expenditure data used for our analysis.

Table 3-9 NAICS-Based Capital Expenditure Data

Oil and Natural Gas Segment	NAICS Code	NAICS Description	Total New Expenditures (millions, current \$)
Production	2111	Crude Petroleum and Natural Gas Extraction	\$158,911
	213111, 213112	Support Activities for Oil and Gas Operations	\$19,966
Transmission and Storage	4862	Pipeline transportation of natural gas	\$12,891

²¹ Capital Expenditures for Structures and Equipment for Companies With Employees by Industry: 2013, Table 4a. See http://www.census.gov/econ/aces/xls/2013/full_report.html

For fugitive emissions standards at well sites and compressor stations, there are no actual capital cost identified in the TSD. First year costs, which are corporate-based costs for these standards are factored into the annual costs; however, these first year costs are not actual capital costs and we therefore, determined that comparison of these costs to industry capital expenditures would be inappropriate.

In the second approach, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to determine whether the annualized costs appear reasonable as a percentage of the revenues being generated by the industry. The annualized costs, as calculated for the rule, include capital cost annualized using a seven percent discount rate plus any annually incurred cost for implementation of a control technology. We used annual costs without savings from natural gas recovery in order to present the highest costs. The annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census²². For the annual revenues analysis, we determined the estimated nationwide annualized costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. For example, we used the total annual cost (nationwide) for hydraulically fractured development oil well completions and compared that to the total receipts for the NAICS codes that correspond to oil and natural gas production segment. Table 3-10 below summarizes the revenue data used for our analysis.

Table 3-10 NAICS-Based Revenue Data

Oil and Natural Gas Segment	NAICS Code	NAICS Description	Estimated Receipts (millions 2012\$)
Production	211111	Crude Petroleum and Natural Gas Extraction	\$276,077
	213112	Support Activities for Oil and Gas Operations	\$90,646
Processing	211112	Natural Gas Liquid Extraction	\$49,236
Transmission and Storage	486210	Pipeline Transportation of Natural Gas	\$26,587

²² Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Employment Size for the United States, All Industries: 2012. Release date: 6/22/2015. 2012 County Business Patterns and 2012 Economic Census. For information on confidentiality protection, sampling error, and nonsampling error, see <http://www.census.gov/econ/susb/methodology.html>. For definitions of estimated receipts and other definitions, see <http://www.census.gov/econ/susb/definitions.html>.

For the capital expenditures, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213111 and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 4862 "Pipeline transportation of natural gas". For revenue, the production segment was represented with the NAICS codes 21111 "Crude Petroleum and Natural Gas Extraction" and 213112 "Support Activities for Oil and Gas Operations". The transmission and storage segment was represented with the NAICS code 486210 "Pipeline Transportation of Natural Gas". Although there is not a one-to-one correspondence between NAICS codes and the industry segments we used in the development of the analysis, we believe there is enough similarity to draw accurate conclusions.

Because we are aware that different owners or operators are generally involved in the different industry segments, we conducted the analysis at the affected facility level to ensure proper characterization of the impact. We also conducted the analysis for all sources in the production segment and in the transmission and storage segment. Table 3-11 summarizes the result of our analysis. In all cases we found that the impacts of the proposed rule in comparison to either capital expenditures or revenues represent a fraction of one percent.

Table 3-11 Comparison of Proposed NSPS Nationwide Cost by Affected Facility Cost to Industry-wide Capital Expenditures and Revenues

Oil and Natural Gas Segment/ Affected Facility	Number of Sources Subject to NSPS	Total Nationwide Capital Costs (millions 2012\$)	Total Nationwide Annual Cost (millions 2012\$)	Nationwide Capital Cost / Capital Expenditur es (%)	Nationwide Annual Cost / Receipts (%)
<i>Production</i>					
Hydraulically Fractured Oil Well Completions and Recompletions					
- Development Oil Wells	13,804	\$144	\$144	0.08%	0.03%
- Exploratory/Delineation Oil Wells	1,166	\$4	\$4	0.00%	0.00%
Gas-Driven Pumps	17,760	\$36	\$5	0.02%	0.00%
Fugitives - Well Sites	138,568	NA	\$310	NA	0.09%
Total Production Segment	171,298	\$184	\$464	0.10%	0.13%
<i>Transmission and Storage</i>					
Compressors					
- Reciprocating	402	\$2.80	\$0.79	0.02%	0.00%
- Centrifugal	6	\$0.14	\$0.02	0.01%	0.00%
Pneumatic Controllers	1,260	\$0.29	\$0.03	0.00%	0.00%
Fugitives - Compressor Stations	1,680	NA	\$27	NA	0.10%
Total Transmission and Storage Segment	3,348	\$3	\$28	0.03%	0.11%

Source : All cost information is from the "Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa" available in the docket. For Hydraulically Fractured Oil Well Completions and Recompletions from Table 4-8, for Gas Driven Pumps from Table 7-19, for Fugitives - Well sites from Table 5-31, for Compressors, Reciprocating from Table 8-13, for Centrifugal from Table 8-14, for Pneumatic controllers from Table 6-9, and for Fugitives - Compressor Stations from Table 5-31.

3.5 Compliance Costs Estimated using 3 and 7 Percent Discount Rates

Table 3-9 shows that the choice of discount rate has very minor effects on the nationwide annualized costs of the proposed option.

Table 3-12 Annualized Costs using 3 and 7 Percent Discount Rates for Proposed NSPS Option 2 in 2020 and 2025 (millions 2012\$)

	Nationwide Annualized Costs, 2020 (2012\$)		Nationwide Annualized Costs, 2025 (2012\$)	
	7 percent	3 percent	7 percent	3 percent
Oil Well Completions and Recompletions	\$120	\$120	\$120	\$120
Fugitive Emissions	\$29 to \$47	\$29 to \$46	\$180 to 290	\$180 to \$290
Pneumatic Pumps	\$0.84	\$0.69	\$5.1	\$4.2
Compressors	\$0.25	\$0.23	\$1.5	\$1.4
Pneumatic Controllers	\$0.0052	\$0.0040	\$0.031	\$0.024
Reporting and Recordkeeping	\$1.4	\$1.4	\$4.1	\$4.1
Total	\$150 to \$170	\$150 to \$170	\$320 to \$420	\$310 to \$420

The choice of discount rate has a small effect on nationwide annualized costs. The compliance costs related to oil well completions and fugitive emissions surveys occur in each year, so the interest rate has little impact on annualized costs for these sources. The annualized costs for pneumatic pumps, compressors, and pneumatic controllers are sensitive to interest rate, but these constitute a relatively small part of the total compliance cost estimates for the proposal.

3.6 Detailed Impacts Tables

The following tables shows the full details of the costs and emissions reduction by emissions sources for each regulatory option in 2020 and 2025.

Table 3-13 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	\$3,200,000	\$3,200,000
Fugitive Emissions							
Well Pads	22,000	17,000	4,800	180	390,000	\$18,000,000	\$25,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	\$4,200,000	\$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	\$340,000	\$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	\$5,900,000	\$840,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	\$470,000	\$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	\$72,000	\$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	\$48,000	\$5,200
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$1,400,000
TOTAL	40,000	170,000	120,000	310	3,800,000	\$180,000,000	\$150,000,000

Table 3-14 Incrementally Affected Units, Emissions Reductions and Costs, Option 1, 2025

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO ₂ Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	\$4,300,000	\$4,300,000
Fugitive Emissions							
Well Pads	140,000	110,000	32,000	1,200	2,600,000	\$110,000,000	\$160,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	\$25,000,000	\$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	\$2,100,000	\$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	\$36,000,000	\$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	\$2,800,000	\$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	\$430,000	\$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	\$290,000	\$31,000
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$4,100,000
TOTAL	180,000	340,000	170,000	1,900	7,700,000	\$330,000,000	\$310,000,000

Table 3-15 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, Low Impact Case, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	\$3,200,000	\$3,200,000
Fugitive Emissions							
Well Pads	13,000	17,000	4,600	180	380,000	\$11,000,000	\$26,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	\$4,200,000	\$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	\$340,000	\$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	\$5,900,000	\$840,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	\$470,000	\$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	\$72,000	\$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	\$48,000	\$5,200
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$1,400,000
TOTAL	31,000	170,000	120,000	310	3,800,000	\$170,000,000	\$150,000,000

Table 3-16 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, Low Impact Case, 2025

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO ₂ Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	\$4,300,000	\$4,300,000
Fugitive Emissions							
Well Pads	84,000	110,000	31,000	1,200	2,500,000	\$68,000,000	\$160,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	\$25,000,000	\$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	\$2,100,000	\$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	\$36,000,000	\$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	\$2,800,000	\$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	\$430,000	\$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	\$290,000	\$31,000
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$4,100,000
TOTAL	120,000	340,000	170,000	1,900	7,700,000	\$280,000,000	\$320,000,000

Table 3-17 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, High Impact Case, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	\$3,200,000	\$3,200,000
Fugitive Emissions							
Well Pads	22,000	26,000	7,200	270	590,000	\$18,000,000	\$43,000,000
Gathering and Boosting Stations	260	5,500	1,500	57	120,000	\$4,200,000	\$2,800,000
Transmission Compressor Stations	21	1,700	47	1	39,000	\$340,000	\$440,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	\$5,900,000	\$840,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	\$470,000	\$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	\$72,000	\$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	\$48,000	\$5,200
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$1,400,000
TOTAL	40,000	180,000	120,000	400	4,000,000	\$180,000,000	\$170,000,000

Table 3-18 Incrementally Affected Units, Emissions Reductions and Costs, Proposed Option 2, High Impact Case, 2025

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	\$4,300,000	\$4,300,000
Fugitive Emissions							
Well Pads	140,000	170,000	48,000	1,800	3,900,000	\$110,000,000	\$270,000,000
Gathering and Boosting Stations	1,600	33,000	9,100	340	740,000	\$25,000,000	\$17,000,000
Transmission Compressor Stations	130	10,000	280	8	230,000	\$2,100,000	\$2,600,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	\$36,000,000	\$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	\$2,800,000	\$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	\$430,000	\$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	\$290,000	\$31,000
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$4,100,000
TOTAL	180,000	400,000	180,000	2,500	9,000,000	\$330,000,000	\$420,000,000

Table 3-19 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2020

Source/Emissions Point	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2 Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	870	8,000	6,700	1	180,000	\$3,200,000	\$3,200,000
Fugitive Emissions							
Well Pads	22,000	34,000	9,600	360	780,000	\$18,000,000	\$81,000,000
Gathering and Boosting Stations	260	7,300	2,000	76	170,000	\$4,200,000	\$5,400,000
Transmission Compressor Stations	21	2,300	63	2	52,000	\$340,000	\$780,000
Pneumatic Pumps							
Well Pads	3,000	5,400	1,500	57	120,000	\$5,900,000	\$840,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	67	1,500	40	1	33,000	\$470,000	\$130,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	1	110	3	0	2,500	\$72,000	\$110,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	210	590	16	0	13,000	\$48,000	\$5,200
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$1,400,000
TOTAL	40,000	190,000	130,000	510	4,200,000	\$180,000,000	\$210,000,000

Table 3-20 Incrementally Affected Units, Emissions Reductions and Costs, Option 3, 2025

Source	Incrementally Affected Units	Nationwide Emissions Reductions				National Costs (2012\$)	
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO ₂ Eq.)	Capital Costs	Ann. Costs With Addl. Revenues
Well Completions							
Hydraulically Fractured Development Oil Wells	14,000	130,000	110,000	13	2,900,000	\$140,000,000	\$120,000,000
Hydraulically Fractured Wildcat and Delineation Oil Wells	1,200	11,000	9,000	1	240,000	\$4,300,000	\$4,300,000
Fugitive Emissions							
Well Pads	140,000	230,000	64,000	2,400	5,200,000	\$110,000,000	\$510,000,000
Gathering and Boosting Stations	1,600	44,000	12,000	460	990,000	\$25,000,000	\$32,000,000
Transmission Compressor Stations	130	14,000	380	11	310,000	\$2,100,000	\$4,700,000
Pneumatic Pumps							
Well Pads	18,000	32,000	9,000	340	740,000	\$36,000,000	\$5,100,000
Gathering and Boosting Stations	0	0	0	0	0	\$0	\$0
Transmission and Storage Compressor Stations	0	0	0	0	0	\$0	\$0
Pneumatic Controllers -							
Natural Gas Transmission and Storage Stations	400	8,800	240	7	200,000	\$2,800,000	\$790,000
Reciprocating Compressors							
Natural Gas Transmission and Storage Stations	6	670	18	1	15,000	\$430,000	\$680,000
Centrifugal Compressors							
Natural Gas Transmission and Storage Stations	1,300	3,500	97	3	80,000	\$290,000	\$31,000
Reporting and Recordkeeping	All	0	0	0	0	\$0	\$4,100,000
TOTAL	180,000	470,000	200,000	3,200	11,000,000	\$330,000,000	\$680,000,000

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed NSPS amendments are expected to prevent new emissions from the oil and gas sector. For the proposed NSPS, there will be climate benefits from methane reductions, ozone and PM_{2.5} health benefits from VOC reductions, and HAP “co-benefits”. These co-benefits occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions. The proposed NSPS is anticipated to prevent 170,000 to 180,000 tons of methane, 120,000 tons of VOC, and 310 to 400 tons of HAP from new sources in 2020. In 2025, the NSPS would prevent 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are estimated to be 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025. As described in the subsequent sections, these pollutants are associated with substantial climate, health, and welfare effects. The only benefits monetized in this RIA are methane-related climate benefits. The methane-related climate effects are estimated to be \$200 to \$210 million and \$460 to \$550 million using a 3 percent discount rate in 2020 and 2025, respectively. The specific control techniques for the proposed NSPS are anticipated to have minor emissions disbenefits (e.g., increases in emissions of carbon dioxide (CO₂), nitrogen oxides (NO_x), PM, carbon monoxide (CO), and total hydrocarbons (THC)) and emission changes associated with the energy system impacts.

While we expect that the avoided VOC emissions will also result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, fine particulate matter (PM_{2.5}), and HAP, we have determined that quantification of the VOC-related health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that these benefits do not exist; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With the data available, we are not able to provide a credible health benefits estimates for this rule, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP

and VOC reductions.²³ In this chapter, we provide a qualitative assessment of the health benefits associated with reducing exposure to these pollutants, as well as visibility impairment and ecosystem benefits. Table 4-1 summarizes the quantified and unquantified benefits in this analysis.

Table 4-1 Climate and Human Health Effects of Emission Reductions from this Proposal

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from methane and carbon dioxide (CO ₂)	— ¹	✓	Marten <i>et al.</i> (2014), SC-CO ₂ TSDs
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA ²
Improved Human Health				
Reduced incidence of premature mortality from exposure to PM _{2.5}	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	—	—	PM ISA ³
	Infant mortality (age <1)	—	—	PM ISA ³
Reduced incidence of morbidity from exposure to PM _{2.5}	Non-fatal heart attacks (age > 18)	—	—	PM ISA ³
	Hospital admissions—respiratory (all ages)	—	—	PM ISA ³
	Hospital admissions—cardiovascular (age >20)	—	—	PM ISA ³
	Emergency room visits for asthma (all ages)	—	—	PM ISA ³
	Acute bronchitis (age 8-12)	—	—	PM ISA ³
	Lower respiratory symptoms (age 7-14)	—	—	PM ISA ³
	Upper respiratory symptoms (asthmatics age 9-11)	—	—	PM ISA ³
	Asthma exacerbation (asthmatics age 6-18)	—	—	PM ISA ³
	Lost work days (age 18-65)	—	—	PM ISA ³
	Minor restricted-activity days (age 18-65)	—	—	PM ISA ³
	Chronic Bronchitis (age >26)	—	—	PM ISA ³
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA ³
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA ³
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA ²
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA ²

²³ Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient PM_{2.5} levels and the health effects associated with PM_{2.5} exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and PM_{2.5} and the highly localized nature of air quality responses associated with VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced incidence of mortality from exposure to ozone	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA ^{2,4}
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA ^{2,4}
	Premature mortality based on short-term study estimates (all ages)	—	—	Ozone ISA ³
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA ³
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	—	—	Ozone ISA ³
	Hospital admissions—respiratory causes (age <2)	—	—	Ozone ISA ³
	Emergency department visits for asthma (all ages)	—	—	Ozone ISA ³
	Minor restricted-activity days (age 18–65)	—	—	Ozone ISA ³
	School absence days (age 5–17)	—	—	Ozone ISA ³
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA ³
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA ²
	Cardiovascular and nervous system effects	—	—	Ozone ISA ²
Reduced incidence of morbidity from exposure to HAP	Reproductive and developmental effects	—	—	Ozone ISA ^{2,4}
	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS ^{2,3}
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA ³
	Visibility in residential areas	—	—	PM ISA ³
Reduced effects from PM deposition (organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA ²
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA ³
	Reduced vegetation growth and reproduction	—	—	Ozone ISA ³
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA ³
	Damage to urban ornamental plants	—	—	Ozone ISA ²
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA ³
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA ²
	Other non-use effects	—	—	Ozone ISA ²
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA ²

¹ The global climate and related impacts of CO₂ and CH₄ emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CO₂ and SC-CH₄. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in CO₂ emissions.

² We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.

³ We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.

⁴ We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

4.2 Emission Reductions from the Proposed NSPS

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for methane, VOC, and HAP, including wells, well sites, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing this rule, emission controls may lead to reductions in ambient PM_{2.5} and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and PM_{2.5} formation to VOC emission reductions, we are unable to determine how this rule might affect attainment status without air quality modeling data.²⁴ Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources.²⁵ By contrast, the emission reductions for implementation rules, including this rule, are generally from a specific class of well-characterized sources. In general, the EPA is more confident in the magnitude and location of the emission reductions for implementation rules rather than illustrative NAAQS analyses. Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS.

²⁴ The responsiveness of ozone and PM_{2.5} formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

²⁵ NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, some costs and benefits estimated in this RIA may account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

Table 4-2 shows the direct emission reductions anticipated for this rule, across the regulatory options examined in the rule. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of PM_{2.5} and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas, and have global impacts. Methane is also a precursor to global background concentrations of ozone.

Table 4-2 Direct Emission Reductions across NSPS Regulatory Options in 2020 and 2025

Pollutant	Option 1	Option 2 (proposed)	Option 3
		2020	
Methane (short tons/year)	170,000	170,000 to 180,000	190,000
VOC (short tons/year)	120,000	120,000	130,000
HAP (short tons/year)	310	310 to 400	510
Methane (metric tons)	150,000	150,000 to 160,000	170,000
Methane (metric tons CO ₂ Eq.)	3,800,000	3,800,000 to 4,000,000	4,200,000
2025			
Methane (short tons/year)	340,000	340,000 to 400,000	470,000
VOC (short tons/year)	170,000	170,000 to 180,000	200,000
HAP (short tons/year)	1,900	1,900 to 2,500	3,200
Methane (metric tons)	310,000	310,000 to 360,000	430,000
Methane (metric tons CO ₂ Eq.)	7,700,00	7,700,000 to 9,000,000	11,000,000

4.3 Methane

4.3.1 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of

global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m² of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO₂. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.97 W/m² of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013 (published April 2015) estimates 2013 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 182 MMt CO₂ Eq. In 2013, total methane emissions from the oil and gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO₂ Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2015c).

It is important to note that the 2013 GHG emissions estimates do not include methane emissions from hydraulically fractured and re-fractured oil well completions due to lack of available data when the 2013 GHG Inventory estimate was developed. The estimate in this proposed rule includes an adjustment for hydraulically fractured oil wells, and such an adjustment is also being considered as a planned improvement in the 2014 Inventory (to be published April 2016). This adjustment would increase the 2013 Inventory methane estimate by about 3 MMt CO₂ Eq. The total methane emissions from Petroleum and Natural Gas Systems based on the 2013 GHG Inventory, adjusted for hydraulically fractured and re-fractured oil well completions, is approximately 185 MMt CO₂ Eq.

Actions taken to comply with the proposed NSPS are anticipated to significantly decrease methane emissions from the oil and natural gas sector in the United States. The proposed NSPS

is expected to reduce methane emissions by about 170,000 to 180,000 short tons or approximately 150,000 to 160,000 metric tons methane (or 3.8 to 4.0 MMt CO₂ Eq.) in 2020. In 2025, the proposed NSPS is expected to reduce methane emissions by about 340,000 to 400,000 short tons or approximately 310,000 to 360,000 metric tons methane (or 7.7 to 9.0 MMt CO₂ Eq.). These reductions in 2020 and 2025 represent about 2 percent and 4 to 5 percent, respectively, of the GHG emissions for this sector (excluding petroleum refineries and petroleum transportation) reported in the 1990-2013 U.S. GHG Inventory (182 MMt CO₂ Eq.).

We calculated the global social benefits of methane emissions reductions expected from the proposed NSPS using estimates of the social cost of methane (SC-CH₄), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The SC-CH₄ estimates applied in this analysis were developed by Marten *et al.* (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO₂ (SC-CO₂), provides important context for understanding the Marten *et al.* SC-CH₄ estimates. Estimates of the SC-CO₂ have been used by the EPA and other federal agencies to value the impacts of CO₂ emissions changes in benefit cost analysis for GHG-related rulemakings since 2008. The SC-CO₂ is a metric that estimates the monetary value of impacts associated with marginal changes in CO₂ emissions in a given year. Similar to the SC-CH₄, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is used to quantify the benefits of reducing CO₂ emissions, or the disbenefit from increasing emissions, in regulatory impact analyses.

The SC-CO₂ estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO₂ estimates and recommended four global values for use in

regulatory analyses. The SC-CO₂ estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2013 update did not revisit the 2010 modeling decisions with regards to the discount rate, reference case socioeconomic and emission scenarios, and equilibrium climate sensitivity distribution. Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SC-CO₂ Technical Support Document (2010 SC-CO₂ TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO₂ TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).²⁶

The 2010 SC-CO₂ TSD noted a number of limitations to the SC-CO₂ analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO₂ reductions to inform benefit-cost analysis. The new versions of the models offer some improvements in these areas, although further work is warranted.

Accordingly, the EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. The EPA and other agencies also continue to consider feedback on the SC-CO₂ estimates from stakeholders through a range of channels, including public comments on Agency rulemakings that use the SC-CO₂ in supporting analyses and through regular interactions with stakeholders and research analysts implementing the SC-CO₂ methodology used by the IWG. In addition, OMB sought public

²⁶ Both the 2010 SC-CO₂ TSD and the current SC-CO₂ TSD are available at:
<https://www.whitehouse.gov/omb/oira/social-cost-of-carbon>

comment on the approach used to develop the SC-CO₂ estimates through a separate comment period that ended on February 26, 2014.²⁷

After careful evaluation of the full range of comments, the IWG continues to recommend the use of the SC-CO₂ estimates in regulatory impact analysis. With the release of the response to comments, the IWG announced plans to obtain expert independent advice from the National Academy of Sciences to ensure that the SC-CO₂ estimates continue to reflect the best available scientific and economic information on climate change.²⁸ The NRC review will be informed by the public comments received and focus on the technical merits and challenges of potential approaches to improving the SC-CO₂ estimates in future updates.

Concurrent with OMB's publication of the response to comments on SC-CO₂ and announcement of the NRC process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO₂ estimates are one dollar less than the mean SC-CO₂ estimates reported in the November 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3 percent discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

The four SC-CO₂ estimates are: \$13, \$45, \$67, and \$130 per metric ton of CO₂ emissions in the year 2020 (2012 dollars).²⁹ The first three values are based on the average SC-CO₂ from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. Estimates of the SC-CO₂ for several discount rates are included because the literature shows that the SC-CO₂ is sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate

²⁷ For the IWG's response to comments, see <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf>.

²⁸ See <https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions>.

²⁹ The current version of the SC-CO₂ TSD is available at: <link to be added when available>. The TSDs present SC-CO₂ in \$2007. The estimates were adjusted to 2012\$ using the GDP Implicit Price Deflator (1.0804). Also available at: http://www.bea.gov/iTable/index_nipa.cfm. The SC-CO₂ values have been rounded to two significant digits. Unrounded numbers from the 2013 SCC TSD were adjusted to 2012\$ and used to calculate the CO₂ benefits.

to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO₂ across all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO₂ distribution. The SC-CO₂ increases over time because future emissions are expected to produce larger incremental damages as economies grow and physical and economic systems become more stressed in response to greater climate change.

A challenge particularly relevant to this proposal is that the IWG did not estimate the social costs of non-CO₂ GHG emissions at the time the SC-CO₂ estimates were developed. One alternative approach to value methane impacts is to use the global warming potential (GWP) to convert the emissions to CO₂ equivalents which are then valued using the SC-CO₂ estimates.

The GWP measures the cumulative radiative forcing from a perturbation of a non-CO₂ GHG relative to a perturbation of CO₂ over a fixed time horizon, often 100 years. The GWP mainly reflects differences in the radiative efficiency of gases and differences in their atmospheric lifetimes. While the GWP is a simple, transparent, and well-established metric for assessing the relative impacts of non-CO₂ emissions compared to CO₂ on a purely physical basis, there are several well-documented limitations in using it to value non-CO₂ GHG benefits, as discussed in the 2010 SC-CO₂ TSD and previous rulemakings (e.g., U.S. EPA 2012b, 2012d).³⁰ In particular, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases. Gas comparison metrics, such as the GWP, are designed to measure the impact of non-CO₂ GHG emissions relative to CO₂ at a specific point along the pathway from emissions to monetized damages (depicted in Figure 4-1), and this point may differ across measures.



Source: Marten *et al.* 2014

Figure 4-1 Path from GHG Emissions to Monetized Damages

³⁰ See also Reilly and Richards, 1993; Schmalensee, 1993; Fankhauser, 1994; Marten and Newbold, 2012.

The GWP is not ideally suited for use in benefit-cost analyses to approximate the social cost of non-CO₂ GHGs because it ignores important nonlinear relationships beyond radiative forcing in the chain between emissions and damages. These can become relevant because gases have different lifetimes and the SC-CO₂ takes into account the fact that marginal damages from an increase in temperature are a function of existing temperature levels. Another limitation of gas comparison metrics for this purpose is that some environmental and socioeconomic impacts are not linked to all of the gases under consideration, or radiative forcing for that matter, and will therefore be incorrectly allocated. For example, the economic impacts associated with increased agricultural productivity due to higher atmospheric CO₂ concentrations included in the SC-CO₂ would be incorrectly allocated to methane emissions with the GWP-based valuation approach.

Also of concern is the fact that the assumptions made in estimating the GWP are not consistent with the assumptions underlying SC-CO₂ estimates in general, and the SC-CO₂ estimates developed by the IWG more specifically. For example, the 100-year time horizon usually used in estimating the GWP is less than the approximately 300-year horizon the IWG used in developing the SC-CO₂ estimates. The GWP approach also treats all impacts within the time horizon equally, independent of the time at which they occur. This is inconsistent with the role of discounting in economic analysis, which accounts for a basic preference for earlier over later gains in utility and expectations regarding future levels of economic growth. In the case of methane, which has a relatively short lifetime compared to CO₂, the temporal independence of the GWP could lead the GWP approach to underestimate the SC-CH₄ with a larger downward bias under higher discount rates (Marten and Newbold, 2012).³¹

The EPA sought public comments on the valuation of non-CO₂ GHG impacts in previous rulemakings (e.g., U.S. EPA 2012b, 2012d). In general, the commenters strongly encouraged the EPA to incorporate the monetized value of non-CO₂ GHG impacts into the benefit cost analysis, however they noted the challenges associated with the GWP-approach, as discussed above, and encouraged the use of directly-modeled estimates of the SC-CH₄ to overcome those challenges.

³¹ We note that the truncation of the time period in the GWP calculation could lead to an overestimate of SC-CH₄ for near term perturbation years when the SC-CO₂ is based on a sufficiently low or steeply declining discount rate.

The EPA had cited several researchers that had directly estimated the social cost of non-CO₂ emissions using IAMs but noted that the number of such estimates was small compared to the large number of SC-CO₂ estimates available in the literature. The EPA found considerable variation among these published estimates in terms of the models and input assumptions they employ (U.S. EPA, 2012d). These studies differed in the emissions perturbation year, employed a wide range of constant and variable discount rate specifications, and considered a range of baseline socioeconomic and emissions scenarios that have been developed over the last 20 years. Furthermore, at the time, none of the other published estimates of the social cost of non-CO₂ GHG were consistent with the SC-CO₂ estimates developed by the IWG, and most were likely underestimates due to changes in the underlying science since their publication.

Therefore, the EPA concluded that the GWP approach would serve as an interim method of analysis until directly modeled social cost estimates for non-CO₂ GHGs, consistent with the SC-CO₂ estimates developed by the IWG, were developed. The EPA presented GWP-weighted estimates in sensitivity analyses rather than the main benefit-cost analyses.³²

Since then, a paper by Marten *et al.* (2014) provided the first set of published SC-CH₄ estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO₂ estimates.³³ Specifically, the estimation approach of Marten *et al.* used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO₂ estimates. The aggregation method involved distilling the 45 distributions of the SC-CH₄ produced for each emissions year into four estimates: the mean across all models and scenarios using a 2.5 percent, 3 percent, and 5 percent discount rate, and the 95th percentile of the pooled estimates from all models and scenarios using a 3 percent discount rate. The atmospheric lifetime and radiative efficacy of methane used by Marten *et al.* is based on the

³² For example, the 2012 New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry are expected to reduce methane emissions by 900,000 metric tons annually, see <http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf>. Additionally, the 2017-2025 Light-duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, promulgated jointly with the National Highway Traffic Safety Administration, is expected to reduce methane emissions by over 100,000 metric tons in 2025 increasing to nearly 500,000 metric tons in 2050, see <http://www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf>

³³ Marten *et al.* (2014) also provided the first set of SC-N₂O estimates that are consistent with the assumptions underlying the SC-CO₂ estimates.

estimates reported by the IPCC in their Fourth Assessment Report (AR4, 2007), including an adjustment in the radiative efficacy of methane to account for its role as a precursor for tropospheric ozone and stratospheric water. These values represent the same ones used by the IPCC in AR4 for calculating GWPs. At the time Marten *et al.* developed their estimates of the SC-CH₄, AR4 was the latest assessment report by the IPCC. The IPCC updates GWP estimates with each new assessment, and in the most recent assessment, AR5, the latest estimate of the methane GWP ranged from 28-36, compared to a GWP of 25 in AR4. The updated values reflect a number of changes: changes in the lifetime and radiative efficiency estimates for CO₂, changes in the lifetime estimate for methane, and changes in the correction factor applied to methane's GWP to reflect the effect of methane emissions on other climatically important substances such as tropospheric ozone and stratospheric water vapor. In addition, the range presented in the latest IPCC report reflects different choices regarding whether to account for how biogenic and fossil methane have different carbon cycle effects, and for whether to account for climate feedbacks on the carbon cycle for both methane and CO₂ (rather than just for CO₂ as was done in AR4).^{34,35}

Marten *et al.* (2014) discuss these estimates, (SC-CH₄ estimates presented below in Table 4-3), and compare them with other recent estimates in the literature.³⁶ The authors noted that a direct comparison of their estimates with all of the other published estimates is difficult, given the differences in the models and socioeconomic and emissions scenarios, but results from three relatively recent studies offer a better basis for comparison (see Hope (2006), Marten and Newbold (2012), Waldhoff *et al.* (2014)). Marten *et al.* found that in general the SC-CH₄ estimates from their 2014 paper are higher than previous estimates. The higher SC-CH₄ estimates are partially driven by the higher effective radiative forcing due to the inclusion of indirect effects from methane emissions in their modeling. Marten *et al.*, similar to other recent studies, also find that their directly modeled SC-CH₄ estimates are higher than the GWP-weighted

³⁴ *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

³⁵ Note that this proposal uses a GWP value for methane of 25 for CO₂ equivalency calculations, consistent with the GHG emissions inventories and the IPCC Fourth Assessment Report (AR4).

³⁶ Marten *et al.* (2014) estimates are presented in 2007 dollars. These estimates were adjusted for inflation using National Income and Product Accounts Tables, Table 1.1.9, Implicit Price Deflators for Gross Domestic Product (US Department of Commerce, Bureau of Economic Analysis), http://www.bea.gov/iTable/index_nipa.cfm (1.0804) Accessed 3/3/15.

estimates. More detailed discussion of the SC-CH₄ estimation methodology, results and a comparison to other published estimates can be found in Marten *et al.*

Table 4-3 Social Cost of Methane (SC-CH₄), 2012 – 2050^a [in 2012\$ per metric ton]
(Source: Marten *et al.*, 2014^b)

Year	SC-CH ₄			
	5 Percent Average	3 Percent Average	2.5 Percent Average	3 Percent 95th percentile
2012	\$430	\$1,000	\$1,400	\$2,800
2015	\$490	\$1,100	\$1,500	\$3,000
2020	\$580	\$1,300	\$1,700	\$3,500
2025	\$700	\$1,500	\$1,900	\$4,000
2030	\$820	\$1,700	\$2,200	\$4,500
2035	\$970	\$1,900	\$2,500	\$5,300
2040	\$1,100	\$2,200	\$2,800	\$5,900
2045	\$1,300	\$2,500	\$3,000	\$6,600
2050	\$1,400	\$2,700	\$3,300	\$7,200

^a The values are emissions-year specific and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

^b The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO₂ estimates described above. See Corrigendum to Marten *et al.* (2014) for more details
<http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550>.

The application of directly modeled estimates from Marten *et al.* (2014) to benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO₂ estimates. Specifically, the SC-CH₄ estimates in Table 4-3 are used to monetize the benefits of reductions in methane emissions expected as a result of the proposed rulemaking. Forecast changes in methane emissions in a given year, expected as a result of the proposed regulatory action, are multiplied by the SC-CH₄ estimate for that year. To obtain a present value estimate, the monetized stream of future non-CO₂ benefits are discounted back to the analysis year using the same discount rate used to estimate the social cost of the non-CO₂ GHG emission changes. In addition, the limitations for the SC-CO₂ estimates discussed above likewise apply to the SC-CH₄ estimates, given the consistency in the methodology.

The EPA recently conducted a peer review of the application of the Marten *et al.* (2014) non-CO₂ social cost estimates in regulatory analysis and received responses that supported this

application. Three reviewers considered seven charge questions that covered issues such as the EPA's interpretation of the Marten *et al.* estimates, the consistency of the estimates with the SC-CO₂ estimates, the EPA's characterization of the limits of the GWP-approach to value non-CO₂ GHG impacts, and the appropriateness of using the Marten *et al.* estimates in regulatory impact analyses. The reviewers agreed with the EPA's interpretation of Marten *et al.*'s estimates; generally found the estimates to be consistent with the SC-CO₂ estimates; and concurred with the limitations of the GWP approach, finding directly modeled estimates to be more appropriate. While outside of the scope of the review, the reviewers briefly considered the limitations in the SC-CO₂ methodology (e.g., those discussed earlier in this section) and noted that because the SC-CO₂ and SC-CH₄ methodologies are similar, the limitations also apply to the resulting SC-CH₄ estimates. Two of the reviewers concluded that use in RIAs of the SC-CH₄ estimates developed by Marten *et al.* and published in the peer-reviewed literature is appropriate, provided that the Agency discuss the limitations, similar to the discussion provided for SC-CO₂ and other economic analyses. All three reviewers encouraged continued improvements in the SC-CO₂ estimates and suggested that as those improvements are realized they should also be reflected in the SC-CH₄ estimates, with one reviewer suggesting the SC-CH₄ estimates lag this process. The EPA supports continued improvement in the SC-CO₂ estimates developed by the U.S. government and agrees that improvements in the SC-CO₂ estimates should also be reflected in the SC-CH₄ estimates. The fact that the reviewers agree that the SC-CH₄ estimates are generally consistent with the SC-CO₂ estimates that are recommended by OMB's guidance on valuing CO₂ emissions reductions, leads the EPA to conclude that use of the SC-CH₄ estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis.

In light of the favorable peer review and past comments urging the EPA to value non-CO₂ GHG impacts in its rulemakings, the Agency has used the Marten *et al.* (2014) SC-CH₄ estimates to value methane impacts expected from this proposed rulemaking and has included those benefits in the main benefits analysis. The EPA seeks comments on the use of these directly modeled estimates, from the peer-reviewed literature, for the social cost of non-CO₂ GHGs in this RIA.

The methane benefits are presented below in Table 4-4 for years 2020 and 2025 across regulatory options. Applying this approach to the methane reductions estimated for the proposed NSPS option, the 2020 methane benefits vary by discount rate and range from about \$88 million to approximately \$550 million; the mean SC-CH₄ at the 3 percent discount rate results in an estimate of about \$200 to \$210 million in 2020. The methane benefits increase for the proposed option in 2025 and likewise vary by discount rate, ranging from about \$220 million to approximately \$1.4 billion in that year; the mean SC-CH₄ at the 3-percent discount rate results in an estimate of about \$460 to \$550 million in 2025.

Table 4-4 Estimated Global Benefits of Methane Reductions* (in millions, 2012\$)

Discount rate and statistic	Option 1		Proposed Option 2 (Low)		Proposed Option 2 (High)		Option 3	
	2020	2025	2020	2025	2020	2025	2020	2025
Million metric tonnes of methane reduced	0.15	0.31	0.15	0.31	0.16	0.36	0.17	0.43
Million metric tonnes of CO ₂ Eq.	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11
5% (average)	\$89	\$220	\$88	\$220	\$93	\$250	\$99	\$300
3% (average)	\$200	\$470	\$200	\$460	\$210	\$550	\$220	\$640
2.5% (average)	\$260	\$600	\$260	\$600	\$280	\$700	\$290	\$830
3% (95 th percentile)	\$530	\$1,200	\$520	\$1,200	\$550	\$1,400	\$590	\$1,700

*The SC-CH₄ values are dollar-year and emissions-year specific. SC-CH₄ values represent only a partial accounting of climate impacts.

The vast majority of this proposal's climate-related benefits are associated with methane reductions, but some climate-related impacts are expected from the proposal's secondary air impacts. The secondary impacts are discussed in Section 4.7.

Methane is also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2013). Approximately 40 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (HTAP, 2010). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (HTAP, 2010). Unlike NO_x and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime (HTAP, 2010). Reducing methane emissions, therefore, can reduce global background ozone concentrations, human exposure to ozone, and the incidence of ozone-related health

effects (West *et al.*, 2006, Anenberg *et al.*, 2009). These benefits are global and occur in both urban and rural areas. Reductions in background ozone concentrations can also have benefits for agriculture and ecosystems (UNEP/WMO, 2011). Studies show that controlling methane emissions can reduce global ozone concentrations and climate change simultaneously, but controlling other shorter-lived ozone precursors such as NO_x, carbon monoxide, or non-methane VOCs have larger local health benefits from greater reductions in local ozone concentrations (West and Fiore, 2005; West *et al.*, 2006; Fiore *et al.*, 2008; Dentener *et al.*, 2005; Shindell *et al.*, 2005, 2012; UNEP/WMO, 2011). The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without detailed air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

Recently, a paper was published in the peer-reviewed scientific literature that presented a range of estimates of the monetized ozone-related mortality benefits of reducing methane emissions (Sarofim *et al.* 2015). For example, under their base case assumptions using a 3% discount rate, Sarofim *et al.* find global ozone-related mortality benefits of methane emissions reductions to be \$790 per tonne of methane in 2020, with 10.6%, or \$80, of this amount resulting from mortality reductions in the United States. The methodology used in this study is consistent in some (but not all) aspects with the modeling underlying the SC-CO₂ and SC-CH₄ estimates discussed above, and required a number of additional assumptions such as baseline mortality rates and mortality response to ozone concentrations. The Sarofim *et al.* (2015) study may have implications for this benefits analysis as it provides a potential approach to estimating the ozone related mortality benefits resulting from the methane reductions expected from this proposed rulemaking. The EPA requests comment on Sarofim *et al.*'s approach to estimating the ozone related mortality benefits of methane emissions reductions, including technical considerations in applying their methodology to this regulatory impact analysis.

4.4 VOC as a PM_{2.5} precursor

This rulemaking would reduce emissions of VOC, which are a precursor to PM_{2.5}. Most VOC emitted are oxidized to CO₂ rather than to PM, but a portion of VOC emission contributes to ambient PM_{2.5} levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce PM_{2.5} formation, human exposure to PM_{2.5}, and the incidence of PM_{2.5}-

related health effects. However, we have not quantified the PM_{2.5}-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 µg/m³.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform air quality modeling for this rule needed to quantify the PM_{2.5} benefits associated with reducing VOC emissions. Due to the high degree of variability in the responsiveness of PM_{2.5} formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient PM_{2.5} levels without air quality modeling. However, we provide the discussion below for context regarding findings from previous modeling.

4.4.1 PM_{2.5} health effects and valuation

Reducing VOC emissions would reduce PM_{2.5} formation, human exposure, and the incidence of PM_{2.5}-related health effects. Reducing exposure to PM_{2.5} is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated PM_{2.5}- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, the EPA generally quantifies several health effects associated with exposure to PM_{2.5} (e.g., U.S. EPA (2011g)). These health effects include premature mortality for adults and infants; cardiovascular morbidity, such as heart attacks; respiratory morbidity, such as asthma attacks and acute and chronic bronchitis; which result in hospital and ER visits, lost work days, restricted activity days, and respiratory symptoms. Although the EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to

PM_{2.5} is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

When the EPA quantifies PM_{2.5}-related benefits, the Agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of PM_{2.5} in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient PM_{2.5} levels and the health effects associated with PM_{2.5} exposure (Fann, Fulcher, and Hubbell, 2009), and these estimates can provide useful context for this rulemaking. Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from \$560 in Seattle, WA to \$5,700 in San Joaquin, CA, with a national average of \$2,400. These estimates assume a 50 percent reduction in VOC, the Laden *et al.* (2006) mortality function (based on the Harvard Six Cities study, a large cohort epidemiology study in the Eastern U.S., an analysis year of 2015, a 3 percent discount rate, and 2006\$). Additional benefit-per-ton estimates are available from this dataset using alternate assumptions regarding the relationship between PM_{2.5} exposure and premature mortality from empirical studies and supplied by experts (e.g., Pope *et al.*, 2002; Laden *et al.*, 2006; Roman *et al.*, 2008). The EPA generally presents a range of benefits estimates derived from the American Cancer Society cohort (e.g., Pope *et al.*, 2002; Krewski *et al.*, 2009) to the Harvard Six Cities cohort (e.g., Laden *et al.*, 2006; Lepuele *et al.*, 2012) because the studies are both well-designed and extensively peer reviewed, and the EPA provides the benefit estimates derived from expert opinions in Roman *et al.* (2008) as a characterization of uncertainty. As shown in Table 4-5, the range of VOC benefits that reflects the range of epidemiology studies and the range of the urban

areas is \$300 to \$7,500 per ton of VOC reduced (2012\$).³⁷ Since these estimates were presented in the 2012 Oil and Gas NSPS RIA (U.S. EPA, 2012b), we updated our methods to apply more recent epidemiological studies for these cohorts (i.e., Krewski *et al.*, 2009; Lepuele *et al.*, 2012) as well as additional updates to the morbidity studies and population data.³⁸ Because these updates would not lead to significant changes in the benefit-per-ton estimates for VOC, we have not updated them here.

While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and PM_{2.5}, these factors lead the EPA to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of this rule, even as a bounding exercise.

³⁷ We also converted the estimates from Fann, Fulcher, and Hubbell (2009) to 2012\$ and applied EPA's current value of a statistical life (VSL) estimate. For more information regarding EPA's current VSL estimate, please see Section 5.6.5.1 of the RIA for the PM NAAQS RIA (U.S. EPA, 2012c). EPA continues to work to update its guidance on valuing mortality risk reductions.

³⁸ For more information regarding these updates, please see Section 5.3 of the RIA for the final PM NAAQS (U.S. EPA, 2012c).

Table 4-5 Monetized Benefits-per-Ton Estimates for VOC based on Previous Modeling in 2015 (2012\$)

Area	Pope <i>et al.</i> (2002)	Laden <i>et al.</i> (2006)	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	\$660	\$1,600	\$1,700	\$1,300	\$1,300	\$920	\$2,100	\$1,200	\$780	\$980	\$1,300	\$1,000	\$260	\$1,000
Chicago	\$1,600	\$4,000	\$4,200	\$3,300	\$3,200	\$2,300	\$5,300	\$3,000	\$1,900	\$2,400	\$3,200	\$2,600	\$640	\$2,500
Dallas	\$320	\$790	\$830	\$650	\$630	\$450	\$1,000	\$580	\$380	\$480	\$630	\$510	\$130	\$490
Denver	\$770	\$1,900	\$2,000	\$1,500	\$1,500	\$1,100	\$2,400	\$1,400	\$910	\$1,100	\$1,500	\$1,200	\$300	\$910
NYC/ Philadelphia	\$2,300	\$5,600	\$5,900	\$4,600	\$4,500	\$3,200	\$7,300	\$4,100	\$2,700	\$3,400	\$4,500	\$3,600	\$890	\$3,300
Phoenix	\$1,100	\$2,700	\$2,800	\$2,200	\$2,100	\$1,500	\$3,500	\$2,000	\$1,300	\$1,600	\$2,100	\$1,700	\$420	\$1,600
Salt Lake	\$1,400	\$3,300	\$3,500	\$2,700	\$2,700	\$1,900	\$4,400	\$2,500	\$1,600	\$2,000	\$2,700	\$2,200	\$570	\$2,100
San Joaquin	\$3,100	\$7,500	\$7,900	\$6,100	\$6,000	\$4,300	\$9,700	\$5,500	\$3,600	\$4,500	\$6,000	\$4,900	\$1,400	\$4,600
Seattle	\$300	\$730	\$770	\$570	\$590	\$420	\$950	\$540	\$350	\$440	\$580	\$470	\$120	\$350
National average	\$1,300	\$3,200	\$3,400	\$2,600	\$2,600	\$1,800	\$4,200	\$2,300	\$1,500	\$1,900	\$2,500	\$2,100	\$520	\$1,900

* These estimates assumed a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been adjusted from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and the EPA's current VSL estimate. However, these estimates have not been updated to reflect recent epidemiological studies for mortality studies, morbidity studies, or population data. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. The EPA generally presents a range of benefits estimates derived from the expert functions from Roman *et al.* (2008) as a characterization of uncertainty.

4.4.2 *Organic PM welfare effects*

According to the previous residual risk assessment for this sector (U.S. EPA, 2012a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a). This summary is from section 6.6.1 of the 2012 PM NAAQS RIA (U.S. EPA, 2012c).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers *et al.*, 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is

counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.4.3 *Visibility Effects*

Reducing secondary formation of PM_{2.5} from VOC emissions would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2011a; U.S. EPA, 2011g; U.S. EPA, 2012c) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.5 VOC as an Ozone Precursor

This rulemaking would reduce emissions of VOC, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NO_x), react in the presence of sunlight. In urban areas, compounds representing all classes of VOC are important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a, 2014b). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a

benefit-per-ton estimate, particularly for sectors with substantial new growth. Third, the impact of reducing VOC emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOC. Rural areas and downwind suburban areas are often NO_x-limited, which means that ozone concentrations are most effectively reduced by lowering NO_x emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NO_x and VOC.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform air quality modeling for this rule needed to quantify the ozone benefits associated with reducing VOC emissions. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions and data limitations regarding the location of new and modified well sites, we are unable to estimate the effect that reducing VOC will have on ambient ozone concentrations without air quality modeling.

4.5.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2013). When adequate data and resources are available, the EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. The scientific literature is also suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, the EPA estimated that reducing 15,000 tons of VOC from industrial boilers resulted in \$3.6 to \$15 million (2008\$) of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).³⁹ After updating the currency year to 2012\$, this implies a

³⁹ While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NO_x emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

benefit-per-ton for ozone of \$260 to \$1,070 per ton of VOC reduced. Since EPA conducted the analysis of industrial boilers, the EPA published the *Integrated Science Assessment for Ozone* (U.S. EPA, 2013), the *Health Risk and Exposure Assessment for Ozone* (U.S. EPA, 2014a), and the RIA for the proposed Ozone NAAQS (U.S. EPA, 2014b). Therefore, the ozone mortality studies applied in the boiler analysis, while current at that time, do not reflect the most updated literature available. The selection of ozone mortality studies used to estimate benefits in RIAs was revisited in the RIA for the proposed Ozone NAAQS. Applying the more recent studies would lead to benefit-per-ton estimates for ozone within the range shown here. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those estimates provide useful estimates of the monetized benefits of this rule, even as a bounding exercise.

4.5.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as “ozone-sensitive”, many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

4.5.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing greenhouse gas (GHG) (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun’s harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study

reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO₂ and methane. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

4.6 Hazardous Air Pollutant (HAP) Benefits

When looking at exposures from all air toxic sources of outdoor origin across the U.S., we see that emissions declined by approximately 42 percent since 1990. However, despite this decline, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).⁴⁰ The levels of air toxics to which people are exposed vary depending on where they live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, the EPA conducts the NATA.⁴¹ The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

- 1) Compiling a national emissions inventory of air toxics emissions from outdoor sources
- 2) Estimating ambient concentrations of air toxics across the U.S. utilizing dispersion models
- 3) Estimating population exposures across the U.S. utilizing exposure models
- 4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, the EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall

⁴⁰ The 2005 NATA is available on the Internet at <http://www.epa.gov/ttn/atw/nata2005/>.

⁴¹ The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. <http://www.epa.gov/ttn/atw/nata2005/>

cancer risks are formaldehyde and benzene.^{42,43} Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,⁴⁴ subchronic,⁴⁵ or acute⁴⁶ inhalation exposure to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-2 and Figure 4-3 depict the 2005 NATA estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions were more than double acrolein emissions on a national basis in the EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more

⁴² Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at <http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2>.

⁴³ Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at <http://www.epa.gov/ttn/atw/nata/roy/page16.html>.

⁴⁴ Chronic exposure is defined in the glossary of the Integrated Risk Information System (IRIS) database (<http://www.epa.gov/iris>) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10 of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

⁴⁵ Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10 of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

⁴⁶ Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

toxic than acetaldehyde.⁴⁷ Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

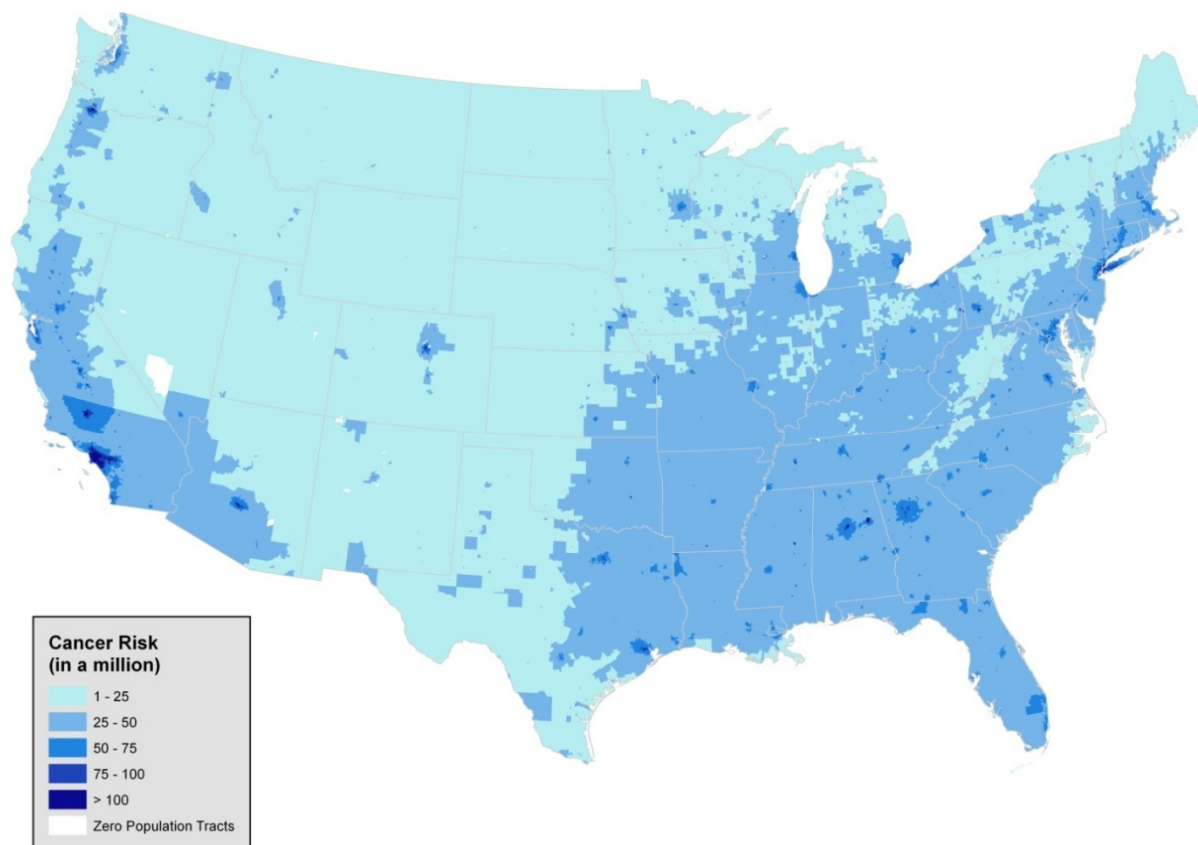


Figure 4-2 2005 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2005 National Toxics Inventory

⁴⁷ Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at <http://cfpub.epa.gov/ncea/iris/compare.cfm>.

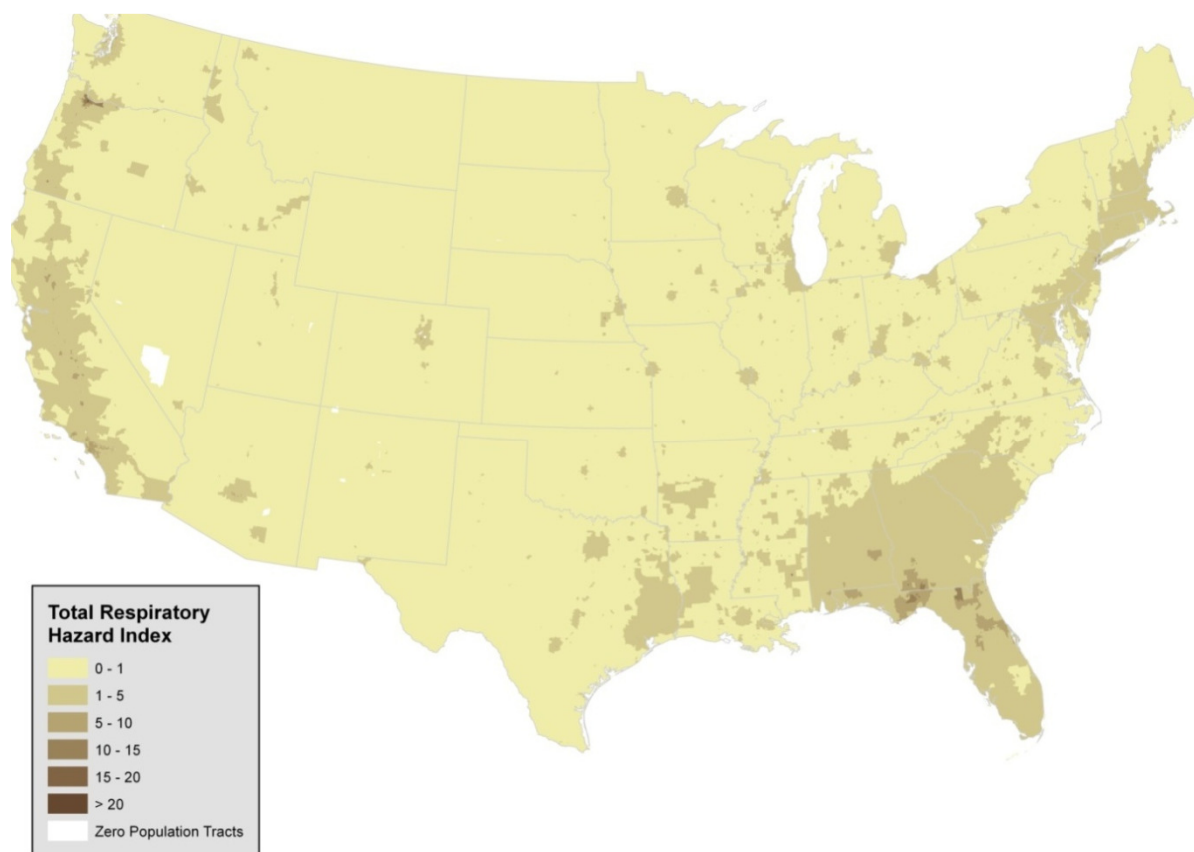


Figure 4-3 2005 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2005 National Toxics Inventory

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of this rule. In a few previous analyses of the benefits of reductions in HAP, the EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) and reference concentrations (RfC) developed through risk assessment procedures. The URF is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu\text{g}/\text{m}^3$ of a pollutant. These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure

to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious noncancer health effects during a lifetime. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, the EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), the EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, the EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAP) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, the EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn *et al.*, 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP anticipated to be reduced by this rule. The EPA remains committed to

improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2012a). In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. This rule is anticipated to avoid or reduce 2,500 tons of HAP in 2025. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

4.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.^{48,49,50} The EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human

⁴⁸ U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <http://www.epa.gov/iris/subst/0276.htm>.

⁴⁹ International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

⁵⁰ Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, *Proc. Natl. Acad. Sci.* 89:3691-3695.

Services has characterized benzene as a known human carcinogen.^{51,52} A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.^{53,54} The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.^{55,56} In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.^{57,58,59,60} The EPA's IRIS program has not yet evaluated these new data.

4.6.2 Toluene⁶¹

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer

⁵¹ International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

⁵² U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: <http://ntp.niehs.nih.gov/go/16183>.

⁵³ Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. *Environ. Health Perspect.* 82: 193-197.

⁵⁴ Goldstein, B.D. (1988). Benzene toxicity. *Occupational medicine. State of the Art Reviews.* 3: 541-554.

⁵⁵ Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. *Am. J. Ind. Med.* 29: 236-246.

⁵⁶ U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <http://www.epa.gov/iris/subst/0276.htm>.

⁵⁷ Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

⁵⁸ Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, *et al.* (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. *Am. J. Industr. Med.* 42: 275-285.

⁵⁹ Lan, Qing, Zhang, L., Li, G., Vermeulen, R., *et al.* (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. *Science* 306: 1774-1776.

⁶⁰ Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

⁶¹ All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <<http://www.epa.gov/iris/subst/0118.htm>>.

bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.6.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.⁶² No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl

⁶² Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at <http://toxnet.nlm.nih.gov/>. Carbonyl health effects summary available at <http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1>.

sulfide has not undergone a complete evaluation and determination under the EPA's IRIS program for evidence of human carcinogenic potential.⁶³

4.6.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.^{64,65} The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).^{66,67} The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in

⁶³ U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0617.htm>.

⁶⁴ Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. *Am J Ind Med* 7:415-446.

⁶⁵ Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. *Annals NY Acad Sci* 837:15-52.

⁶⁶ International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

⁶⁷ National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.6.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.⁶⁸ Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.⁶⁹ Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.⁷⁰ The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.6.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral

⁶⁸ U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0270.htm>.

⁶⁹ Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

⁷⁰ Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.⁷¹

4.6.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H₂S). Information regarding the health effects of those compounds can be found in the EPA's IRIS database.⁷²

4.7 Secondary Air Emissions Impacts

The control techniques to meet the standards are associated with several types of secondary emissions impacts, which may partially offset the direct benefits of this rule. Table 4-7 shows the estimated secondary emissions impacts. Relative to the direct emission reductions anticipated from this rule, the magnitude of these secondary air pollutant impacts is small.

⁷¹ U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

⁷² U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

Table 4-6 Secondary Air Pollutant Impacts (short tons per year)

Emissions Category	2020				
	CO₂	NO_x	PM	CO	THC
Total Hydraulically Fractured and Re-fractured Oil Well Completions	580,000	300	10	1,600	620
Fugitive Emissions	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>
Pneumatic Pumps	24,000	12	0	66	25
Pneumatic Controllers	0	0	0	0	0
Compressors	550	0	0	2	1
Total 2020	610,000	310	10	1,700	640

Emissions Category	2025				
	CO₂	NO_x	PM	CO	THC
Total Hydraulically Fractured and Re-fractured Oil Well Completions	610,000	310	11	1,700	640
Fugitive Emissions	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>	<i>minimal</i>
Pneumatic Pumps	140,000	72	0	400	150
Pneumatic Controllers	0	0	0	0	0
Compressors	3,300	2	0	9	3
Total in 2025	750,000	380	11	2,100	790

The secondary emission impacts for regulatory options are equal across the options. This result holds because the only requirements varied across the options is the coverage (low and high impact cases of the proposed Option 2) or frequency (Moving from Option 1 to Option 3 increases the frequency of survey and repair under the fugitive emissions requirement) and secondary emissions from the fugitive emissions requirements are expected to be minimal. We are not estimating the monetized disbenefits of the secondary emissions of CO₂ because much of the methane that would have been released in the absence of the flare would have eventually oxidized into CO₂ in the atmosphere. Note that the CO₂ produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC-CH₄.

However, the EPA does recognize that because the growth rate of the SC-CO₂ estimates are lower than their associated discount rates, the estimated impact of CO₂ produced in the future from oxidized methane would be less than the estimated impact of CO₂ released immediately from flaring, which would imply a small disbenefit associated with flaring. Assuming an average methane oxidation period of 8.7 years, consistent with the lifetime used in IPCC AR4, the disbenefits associated with destroying one metric ton of methane and releasing the CO₂

emissions in 2020 instead of being released in the future via the methane oxidation process is estimated to be \$5 to \$25 per metric ton CH₄ depending on the SC-CO₂ value or 0.7 percent to 0.9 percent of the SC-CH₄ estimates per metric ton for 2020. The analogous estimates for 2025 are \$7 to \$34 per metric ton CH₄ or 0.8 percent to 1.0 percent of the SC-CH₄ estimates per metric ton for 2025.⁷³ While the EPA is not accounting for the CO₂ disbenefits at this time, we request comment on the appropriateness of the monetization of such impacts using the SC-CO₂ and aspects of the calculation.

Table 4-7 provides a summary of the direct and secondary emissions changes. Based on this summary and analysis above, the net impact of both the direct and secondary impacts of this proposal would be an improvement in ambient air quality, which would reduce potency of greenhouse gas emissions, reduce exposure to various harmful pollutants, improve visibility impairment, and reduce vegetation damage.

Table 4-7 Summary of Emissions Changes (short tons per year, except where noted)

	Pollutant	Option 1		Proposed Option 2 (Low)		Proposed Option 2 (High)		Option 3	
		2020	2025	2020	2025	2020	2025	2020	2025
Change in Direct Emissions	Methane	170,000	340,000	170,000	340,000	180,000	400,000	190,000	470,000
	VOC	120,000	170,000	120,000	170,000	120,000	180,000	130,000	200,000
	HAP	310	1,900	310	1,900	400	2,500	510	3,200
Change in Secondary Emissions	CO ₂	610,000	750,000	610,000	750,000	610,000	750,000	610,000	750,000
	NOx	310	380	310	380	310	380	310	380
	PM	10	11	10	11	10	11	10	11
	CO	1,700	2,100	1,700	2,100	1,700	2,100	1,700	2,100
	THC	640	790	640	790	640	790	640	790
Net Change in CO₂ Eq. Emissions	CO ₂ Eq. (million short tons)	4.2	8.5	4.2	8.5	4.4	9.9	4.7	12
	CO ₂ Eq. (million metric tons)	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11

Note: Totals may not sum due to independent rounding.

⁷³ To calculate the disbenefits associated the complete destruction of a ton of CH₄ through flaring, EPA took the difference between the SC-CO₂ at the time of the flaring and in 8.7 years and discounted that value to the time of the flaring using the same discount rate as used to estimate the SC-CO₂. This value was then scaled by 44/16 to account for the relative mass of carbon contained in a ton of CH₄ versus a ton of CO₂. The value of the SC-CO₂ 8.7 years after flaring was estimated by linearly interpolating between the annual SC-CO₂ estimates reported in the TSD and inflated to 2012 dollars.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under section 3(f)(1) Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an “economically significant regulatory action” because it is likely to have an annual effect on the economy of \$100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. Tables 6-1 through 6-4 shows the results of the cost and benefits analysis for this proposed rule.

5.2 Paperwork Reduction Act

The Office of Management and Budget (OMB) has previously approved the information collection activities contained in 40 CFR part 60, subpart OOOO under the PRA and has assigned OMB control number 2060-0673 and ICR number 2437.01; a summary can be found at 77 F.R. 49537. The information collection requirements in today’s proposed rule titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (40 CFR part 60 subpart OOOOa) have been submitted for approval to the OMB under the PRA. The ICR document prepared by the EPA has been assigned EPA ICR Number 2523.01. You can find a copy of the ICR in the docket for this rule, and is briefly summarized below.

The information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which

facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of \$3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

5.3 Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than \$7 million for firms that transport natural gas

via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 3 of this RIA. The analysis in the IRFA drew upon the same analysis and assumptions as the analyses presented in RIA. The IRFA analysis is presented in its entirety in Section 7.3 of the RIA.

Identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. To identify potentially affected entities under the proposed NSPS, the EPA combined information from industry databases to identify firms drilling and completing wells in 2012, as well as identified their oil and natural gas production levels for that year.

The EPA based the analysis in the IRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While the IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent a large majority of the estimated compliance costs of the proposed NSPS in 2020 and 2025. Note incorporating impacts from other provisions in this analysis is a limitation and underestimates impacts, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the proposed rule in its entirety.

We projected the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in this RIA. This approach assumes that no other firms perform potentially affected activities and firms performing oil and natural gas activities in 2012 will continue to do so in 2020 and 2025. While likely true for many firms, this will not be the case for all firms.

For some firms, we estimated their 2012 sales levels by multiplying 2012 oil and natural gas production levels reported in an industry database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the \$4/Mcf for natural gas. For oil prices, we estimated revenues using two alternative prices, \$70/bbl and \$50/bbl. In the results, we call the case using \$70/bbl the “primary scenario” and the case using the \$50/bbl as the “low oil price scenario”.

For projected 2020 and 2025 potentially affected activities, we allocated compliance costs across entities based upon the costs estimated in the TSD and used in the RIA. The RIA and IRFA also estimates the potential implications of the proposed exclusion for low producing sites from the fugitive emission requirements. Fewer sites in the program due to this exclusion will likely lead to lower costs and emissions.

The analysis indicates about 1,200 to 2,100 small entities may be subject to the requirements for hydraulically fractured and re-fractured oil well completions and fugitive emissions requirements at well sites. The low end of this range reflects an estimate of how many entities might be excluded as a result of the low production fugitive emissions exemption. Also, the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS. Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the case without the entities that might be excluded from fugitive emissions requirements as a result of the low production exemption.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 3 of the RIA.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel

evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

5.4 Unfunded Mandates Reform Act

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

5.5 Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. These final rules primarily affect private industry and would not impose significant economic costs on state or local governments.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The majority of the units impacted by this rulemaking on tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or a tribal government is given delegated authority to enforce the rulemaking.

The EPA consulted with tribal officials under the “EPA Policy on Consultation and Coordination with Indian Tribes” early in the process of developing this regulation to permit them to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process. We provided an update on the methane strategy on the January 29, 2015, NTAA and EPA Air

Policy call. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

GHGs including methane contribute to climate change and are emitted in significant quantities by the oil and gas sector. The EPA believes that the GHG emission reductions resulting from implementation of these final guidelines will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat

waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section V of this preamble.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies will prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as “significant energy actions.” Section 4(b) of Executive Order 13211 defines “significant energy actions” as any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This action is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-

based estimates of energy system impacts are likely high end estimates. We estimate that natural gas and crude oil production levels remains essentially unchanged in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about \$0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of this proposed rule, please see Section 7 of this RIA.

5.9 National Technology Transfer and Advancement Act (NTTAA) and 1 C.F.R. part 51

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A,

2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 21, 22, and 25A of 40 C.F.R. part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22. All potential standards were reviewed to determine the practicality of the VCS for this rule. In this rule, the EPA is proposing to include in a final EPA rule regulatory text for 40 CFR part 60, subpart OOOOa that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is proposing to incorporate by reference ANSI/ASME PTC 19-10-1981, Flue and Exhaust Gas Analyses (Part 10) to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The EPA has determined this because the rulemaking increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations. The EPA has provided meaningful participation opportunities for minority, low-income, indigenous populations and tribes during the pre-proposal period by conducting community calls and webinars. Additionally, the EPA will conduct outreach for communities after the rulemaking is finalized.

6 COMPARISON OF BENEFITS AND COSTS

Tables 6-1 through Table 6-3 present the summary of the benefits, costs, and net benefits for the NSPS across regulatory options. Table 6-4 provides a summary of the direct and secondary emissions changes for each regulatory option.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 1 in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$200 million	\$470 million
Total Costs ²	\$150 million	\$310 million
Net Benefits ³	\$43 million	\$160 million
	Non-monetized climate benefits	Non-monetized climate benefits
Non-monetized Benefits	Health effects of PM _{2.5} and ozone exposure from 120,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 170,000 tons of VOC reduced
	Health effects of HAP exposure from 310 tons of HAP reduced	Health effects of HAP exposure from 1,900 tons of HAP reduced
	Health effects of ozone exposure from 170,000 tons of methane	Health effects of ozone exposure from 340,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$89 million to \$530 million in 2020 and \$220 million to \$1,200 million in 2025 for the proposed option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 3.8 million metric tons in 2020 and 7.7 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 2 (Proposed Option) in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$200 to \$210 million	\$460 to \$550 million
Total Costs ²	\$150 to \$170 million	\$320 to \$420 million
Net Benefits ³	\$35 to \$42 million	\$120 to \$150 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM _{2.5} and ozone exposure from 120,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 170,000 to 180,000 tons of VOC reduced
	Health effects of HAP exposure from 310 to 400 tons of HAP reduced	Health effects of HAP exposure from 1,900 to 2,500 tons of HAP reduced
	Health effects of ozone exposure from 170,000 to 180,000 tons of methane	Health effects of ozone exposure from 340,000 to 400,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average a 3 percent discount rate. However, we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$88 million to \$550 million in 2020 and \$220 million to \$1,400 million in 2025 for the proposed option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. See Section 4.7 for details.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

Table 6-3 Summary of the Monetized Benefits, Costs, and Net Benefits for Option 3 in 2020 and 2025 (2012\$)

	2020	2025
Total Monetized Benefits ¹	\$220 million	\$640 million
Total Costs ²	\$210 million	\$680 million
Net Benefits ³	\$7.6 million	-\$35 million
Non-monetized Benefits	Non-monetized climate benefits	Non-monetized climate benefits
	Health effects of PM _{2.5} and ozone exposure from 130,000 tons of VOC reduced	Health effects of PM _{2.5} and ozone exposure from 200,000 tons of VOC reduced
	Health effects of HAP exposure from 510 tons of HAP reduced	Health effects of HAP exposure from 3,200 tons of HAP reduced
	Health effects of ozone exposure from 190,000 tons of methane	Health effects of ozone exposure from 470,000 tons of methane
	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects

¹ The benefits estimates are calculated using four different estimates of the social cost of methane (SC-CH₄) (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For purposes of this table, we show the benefits associated with the model average at a 3 percent discount rate. However we emphasize the importance and value of considering the benefits calculated using all four SC-CH₄ estimates; the additional benefit estimates range from \$99 million to \$590 million in 2020 and \$300 million to \$1,700 million in 2025 for this more stringent option, as shown in Section 4.3. The CO₂-equivalent (CO₂ Eq.) methane emission reductions are 4.2 million metric tons in 2020 and 11 million metric tons in 2025. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits.

² The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

³ Estimates may not sum due to independent rounding.

Table 6-4 Summary of Emissions Changes across Options for the NSPS in 2020 and 2025 (short tons per year, unless otherwise noted)

	Pollutant	Option 1		Proposed Option 2 (Low)		Proposed Option 2 (High)		Option 3	
		2020	2025	2020	2025	2020	2025	2020	2025
Change in Direct Emissions	Methane	170,000	340,000	170,000	340,000	180,000	400,000	190,000	470,000
	VOC	120,000	170,000	120,000	170,000	120,000	180,000	130,000	200,000
	HAP	310	1,900	310	1,900	400	2,500	510	3,200
Change in Secondary Emissions	CO ₂	610,000	750,000	610,000	750,000	610,000	750,000	610,000	750,000
	NO _x	310	380	310	380	310	380	310	380
	PM	10	11	10	11	10	11	10	11
	CO	1,700	2,100	1,700	2,100	1,700	2,100	1,700	2,100
	THC	640	790	640	790	640	790	640	790
Net Change in CO₂ Eq. Emissions	CO ₂ Eq. (million short tons)	4.2	8.5	4.2	8.5	4.4	9.9	4.7	12
	CO ₂ Eq. (million metric tons)	3.8	7.7	3.8	7.7	4.0	9.0	4.2	11

Note: Totals may not sum due to independent rounding.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for the proposed NSPS:

- Energy System Impacts
- Initial Regulatory Flexibility Analysis
- Employment Impacts

7.2 Energy System Impacts Analysis

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the proposed rule might alter the mix of fuels consumed at a national level. The EPA only modeled the energy system impacts of the high impact case of the proposed NSPS with respect to the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and presenting results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain in production at the producer level. For example, the analysis for the proposed rule shows that performing reduced emissions completions on hydraulically-fractured oil wells contributes about 75 percent of the natural gas captured by emissions controls in 2020 and about 32 percent of captured natural gas in 2025. The fugitive emissions program at well sites is expected to capture about 18 percent of the natural gas captured by emissions controls in 2020 and about 52 percent of captured natural gas in 2025.

The assumed \$4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers

are paid based upon this metered production. Depending on the situation, the gas captured by a REC is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy (DOE). NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy economy from the current year to 2040. DOE first developed NEMS in the 1980s, and the model has undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at < <http://www.eia.gov/forecasts/aeo/>>.

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel *et al.* 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as “mid-term” projections to the year 2040. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2014.⁷⁴ The RIA baseline is consistent with that of the Annual Energy Outlook 2014 which is used extensively in Section 2 in the Industry Profile.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the proposed rule, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2014). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of

⁷⁴ Assumptions for the 2014 Annual Energy Outlook can be found at <<http://www.eia.gov/forecasts/aeo/assumptions/>>.

extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the proposed NSPS. We are able to target additional expenditures for environmental controls required by the NSPS on new exploratory and developmental oil and gas production activities. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the proposed rule.

While the oil production simulated by the OGSM is sent to the refining module (the Liquid Fuels Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and “negotiates” supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas is transported through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions for hydraulically fractured oil well completions are added to the drilling and completion costs of oil wells in the OGSM.

Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The additional expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells or natural gas wells. We base the per well cost estimates on the engineering costs. Because we model natural gas recovery, we do not include revenues from additional product recovery in these costs. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One caveat in introducing new cost requirements into the model is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the required capital. A caveat to this is that the estimated unit-level capital costs of controls that are newly required at a national-level as a result of the regulation may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental compliance that accrue to new drilling projects as a result of producers having to comply with the NSPS, across sources anticipated in 2020 and 2025. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of the per well costs, we first identify whether costs will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells.

Based on the baseline projections of successful completions in 2020, we used 35,404 new crude oil wells and 8,456 new natural gas wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project (Table 1).

Hydraulically fractured oil wells completions and fugitives at oil and natural gas well sites differ slightly from this approach. Drilling and completion costs of new hydraulically fractured oil wells are incremented by the weighted average of the cost of performing a REC with completion combustion and completion combustion alone. The resulting cost is itself weighted by the proportion of new hydraulically fractured oil wells estimated to be affected by the regulation (70 percent).

Meanwhile, assuming there is an average of two wells per wells site (see TSD for more details), new oil and gas wells face an increased annual cost of one-half of implementing the well site fugitive emission requirements.

Table 7-1 Per Well Costs for Environmental Controls Entered into NEMS (2012\$)

Emissions Sources/Points	Wells Applied To in NEMS	Annualized Cost per Unit (2012\$)	Per New Well Costs Applied in NEMS (2012\$)	Gas Recovery per Unit (Mcf)	Per New Well Gas Recovery Applied in NEMS (Mcf)
Well Completions					
Hydraulically Fractured Oil Well Completions	New Hydraulically Fractured Oil Wells	\$17,182 / \$3723	\$7,067	0	0
Fugitive Emissions					
Oil Production Well Sites	New Oil Wells	\$2,144	\$1,072	38	19
Natural Gas Production Well Sites	New Gas Wells	\$2,144	\$1,072	158	79
Gathering and Boosting Stations	New Gas Wells	\$14,028	\$430	1,222	37
Transmission Stations	New Gas Wells	\$13,879	\$10	1,938	1
Storage Facilities	New Gas Wells	\$21,049	\$37	5,107	9
Reciprocating Compressors					
Transmission Stations	New Gas Wells	\$1,748	\$5	1,122	3
Storage Facilities	New Gas Wells	\$2,077	\$11	1,130	6
Centrifugal Compressors					
Storage Facilities	New Gas Wells	\$114,146	\$13	0	0
Pneumatic Controllers -					
Transmission and Storage Stations	New Gas Wells	\$25	\$1	0	0
Pneumatic Pumps					
Well Sites	New Wells	\$285	\$19	0	0
Reporting and Recordkeeping	New Wells	\$1,381,023*	\$31	0	0

*Note: reporting and recordkeeping costs are assumed to be equally allocated across all new wells.

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A result of controlling methane and VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this

manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

We enter the increased natural gas recovery into NEMS on a per-well basis for new natural gas wells, following an estimation procedure similar to that of entering compliance costs into NEMS on a per-well basis for new wells (Table 7-1). For this analysis, however, we were unable to incorporate the natural gas recovery from performing RECs on hydraulically fractured oil well completions or from other emissions control activities at oil well sites. We hope to make this modification in the RIA for the final rule.

7.2.3 *Energy System Impacts*

As mentioned earlier, we estimate impacts to drilling activity, price and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas.⁷⁵ In each of these estimates, we present estimates for the baseline years of 2020 and 2025 and predicted results for 2020 and 2025 under the proposal. We also presented impacts over the 2020 to 2025 time period. For context, we provide estimates of production activities in 2012. With the exception of examining crude oil and natural gas trade, we focus the analysis on onshore oil and natural gas production activities in the continental (lower 48) U.S. We do this because off-shore production is not affected by the proposed NSPS and the bulk of the proposed rule's impacts are expected in the continental U.S.

We first report estimates of impacts on crude oil and natural gas drilling activities and production. Table 7-2 presents estimates of successful onshore natural gas and crude oil wells drilled in the continental U.S.

⁷⁵ The EPA only modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

Table 7-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)

Table 7-2 Successful Oil and Gas Wells Drilled (Onshore, Lower 48 States)							
		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Successful Wells Drilled							
Natural Gas	10,965	20,298	20,299	24,727	24,800	142,764	142,638
Crude Oil	26,517	24,660	24,660	27,648	27,638	155,201	155,202
Total	37,482	44,959	44,959	52,375	52,438	297,965	297,840
% Change in Successful Wells Drilled from Baseline							
Natural Gas			0.00%		0.30%		-0.09%
Crude Oil			0.00%		-0.04%		0.00%
Total			0.00%		0.12%		-0.04%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

Results show that the proposed NSPS will have a relatively small impact on onshore well drilling in the lower 48 states. Drilling remains essentially unchanged in 2020, but increases for natural gas wells in 2025, while decreasing for crude oil wells in 2025. The increase in natural gas well drilling in 2025 is somewhat counter-intuitive as production costs have been increased under the proposed NSPS. However, given NEMS is a dynamic, multi-period model, it is important to examine changes over multiple time periods. Natural gas well drilling over the 2020 to 2025 period decreases but about 120 wells total. Crude oil drilling, over the same six-year, period remains at the same levels.

Table 7-3 shows estimates of the changes in the domestic production of natural gas and crude oil under the proposed NSPS.

Table 7-3 Annual Domestic Natural Gas and Crude Oil Production (Onshore, Lower 48 States)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Domestic Production							
Natural Gas (trillion cubic feet)	22.075	26.577	26.576	28.931	28.927	167.585	167.576
Crude Oil (million barrels/day)	4.599	7.234	7.234	7.064	7.062	7.174	7.173
Natural Gas			0.00%		-0.01%		-0.01%
Crude Oil			0.00%		-0.03%		-0.01%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

As indicated by the estimated change in the new well drilling activities, the analysis shows that the proposed NSPS will have a relatively small impact on onshore natural gas and crude oil production in the lower 48 states. Again, production levels Drilling remains essentially unchanged in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Total production over the 2020 to 2025 is also estimated to decline for natural gas (by about 9 bcf or 0.01 percent) and crude oil (by about 1,000 barrels per day or about 0.01 percent)

Note this analysis estimates no increase in domestic natural gas production, despite some environmental controls anticipated to be used in response to the proposed rule capture natural gas that would otherwise be emitted (8.2 bcf in 2020 and 19 bcf in 2025). There are two sources for this difference. First, we were unable to incorporate into the model the natural gas recovery from performing RECs on hydraulically fractured oil well completions or from other emissions control activities at oil well sites. Second, NEMS models the adjustment of energy markets to the new slightly more costly natural gas and crude oil productive activities. At the new post-rule equilibrium, producers implementing emissions controls are still anticipated to capture and sell the captured natural gas, and this natural gas might offset other production, but not so much as to make overall production increase from the baseline projections.

Table 7-4 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states.

Table 7-4 Average Natural Gas and Crude Oil Wellhead Price (Onshore, Lower 48 States, 2012\$)

		Projection, 2020		Projection, 2025		Projection, 2020-25	
	2012	Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Lower 48 Average Wellhead Price							
Natural Gas (2012\$ per Mcf)	2.562	4.458	4.458	5.064	5.071	4.670	4.673
Crude Oil (2012\$ per barrel)	94.938	92.913	92.913	104.889	104.887	98.932	98.931
% Change in Lower 48 Average Wellhead Price from Baseline							
Natural Gas			0.00%		0.14%		0.06%
Crude Oil			0.00%		0.00%		0.00%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020, but are estimated to increase about \$0.007 per Mcf or 0.14 percent in 2025. The production weighted average price over the 2020 to 2025 period is estimated to increase by \$0.003 per Mcf or about 0.06 percent. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. This is likely result of both the relatively small scale of the costs of the new compliance requirements, as well as the fact that oil prices are more a function of global prices that are natural gas prices.

Meanwhile, as shown in Table 7-5, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent), 2025 (by about 3 bcf or 0.09 percent), and across the 2020 to 2025 period (by about 4 bcf total or about 0.03 percent). Crude oil imports are estimated to not change in 2020, increase by about 1,000 barrels per day (or 0.02 percent) in 2025 or by about 2,000 barrels per day (or about 0.02 percent) on average during the 2020 to 2025 time period.

Table 7-5 Net Imports of Natural Gas and Crude Oil

	2012	Projection, 2020		Projection, 2025		Projection, 2020-25	
		Baseline	NSPS	Baseline	NSPS	Baseline	NSPS
Net Imports							
Natural Gas (trillion cubic feet)	1.515	-1.901	-1.900	-3.211	-3.208	-15.371	-15.367
Crude Oil (million barrels/day)	8.432	5.781	5.781	6.004	6.005	5.914	5.916
% Change in Net Imports							
Natural Gas			-0.05%		-0.09%		-0.03%
Crude Oil			0.00%		0.02%		0.02%

Note: reflects estimates of the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements.

7.3 Initial Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA; 5 U.S.C. § 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104-121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that

the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. § 605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. An IRFA describes the economic impact of the proposed rule on small entities and any significant alternatives to the proposed rule that would accomplish the objectives of the rule while minimizing significant economic impacts on small entities. Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact.

7.3.1 Reasons why Action is Being Considered

This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The EPA is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category.

7.3.2 Statement of Objectives and Legal Basis for Proposed Rules

The EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category. Specifically, we are proposing both methane and VOC standards for several emission sources not currently covered by the NSPS (i.e., hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, and pneumatic pumps). In addition, we are proposing methane standards for certain emission sources that are currently regulated for VOC (i.e., hydraulically fractured gas well completions, equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the source category, the current NSPS regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The proposed amendments would establish methane standards for these equipment

across the source category and extend the current VOC standards to the remaining unregulated equipment. Lastly, amendments to the current NSPS are being proposed that improve implementation of several aspects of the current standards. These improvements result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue “standards of performance” for new sources in such source categories. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, and identify within each source category the facilities for which standards of performance would be established.

CAA Section 111(a)(1) defines “a standard of performance” as “a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.” This definition makes clear that the standard of performance must be based on controls that constitute “the best system of emission reduction... adequately demonstrated”. The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as “new source performance

standards.” The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to “at least every 8 years review and, if appropriate, revise” performance standards unless the “Administrator determines that such review is not appropriate in light of readily available information on the efficacy” of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

7.3.3 *Description and Estimate of Affected Small Entities*

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The EPA conducted this regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities.⁷⁶ The EPA identified the size of ultimate parent entities by using the Small Business Administration (SBA) size threshold guidelines.⁷⁷ The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as follows:

Table 7-6 SBA Size Standards by NAICS Code

NAICS Codes	NAICS Industry Description	Size Standards (in millions of dollars)	Size Standards (in no. of employees)
211111	Crude Petroleum and Natural Gas Extraction	-	500
211112	Natural Gas Liquid Extraction	-	500
213111	Drilling Oil and Gas Wells	-	500
213112	Support Activities for Oil and Gas Operations	\$38.5	-
486110	Pipeline Transportation of Crude Oil	-	1,500
486210	Pipeline Transportation of Natural Gas	\$27.5	-

Sources: U.S. Census Bureau, Statistics of U.S. Businesses, 2012. <http://www.census.gov/econ/susb/>. SBA Size Standards, 13 CFR 121. 201

We have projections of future potentially affected activities at an aggregate level, but identifying impacts on specific entities is challenging because of the difficulty of predicting

⁷⁶ See Section 2.6 of this RIA for more information on oil and natural gas industry firm characteristics and a breakdown of firms by size at the national level.

⁷⁷ U.S. Small Business Administration (SBA). 2014. Small Business Size Standards. Effective as of July 14, 2014. See: http://www.sba.gov/sites/default/files/Size_Standards_Table.pdf.

potentially affected new or modified source at the firm level. Because of these limitations, we based the analysis in this IRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. We are able to do this because the base year activity counts for the impacts estimates (as described in the TSD) for this rule were based on detailed information for 2012 in a dataset of U.S. wells. The proprietary DrillingInfo dataset contains a variety of information including oil, condensate, and natural gas production levels, geographic locations, as well as basin and formation information, and information about owners/operators of wells, among other data fields.⁷⁸ As described in the TSD sections on hydraulically fractured and re-fractured oil well completions and fugitive emissions, we used the DrillingInfo dataset to identify and estimate all wells that were completed in 2012, as well as completions of hydraulically fracture or re-fractured oil wells.⁷⁹ We used the field called “common operator” to identify the owner/operator of all wells in this set of new or modified 2012 wells.

While the IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent about 97 percent and 94 percent of the estimated compliance costs of the proposed NSPS in 2020 and 2025, respectively (Table 7-7). Note incorporating impacts from other provisions in this analysis is a limitation, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the proposed rule in its entirety.

⁷⁸ DrillingInfo is a private company that provides information and analysis to the energy sector. More information is available at: <http://info.drillinginfo.com>.

⁷⁹ The TSD for this proposed rule provides information on this dataset of U.S. wells. Additional details on the development of this dataset can also be found in the following docketed memo: Memorandum to Mark de Figueiredo, EPA, from Casey MacQueen and Jessica Gray, ERG. “DrillingInfo Processing Methodology”. August 27, 2014.

Table 7-7 Distribution of Estimated Compliance Costs across Sources

	Annualized Costs (With Product Recovery, 2012\$)			
	2020	2020 (%)	2025	2025 (%)
Hydraulically-fractured and Re-fractured Oil Well Completions and Recompletions	\$120,000,000	71%	\$120,000,000	29%
Fugitive Emissions at Well-sites ¹	\$43,000,000	25%	\$270,000,000	64%
Other Sources	\$5,800,000	3%	\$30,000,000	7%
Total Annualized Costs of Proposed NSPS	\$170,000,000	100%	\$420,000,000	100%

¹ Estimates for fugitive emissions requirements based on “high impact” case.

Note: sums may not total due to independent rounding.

To identify potentially affected entities under the proposed NSPS, the EPA combined ownership information from the DrillingInfo dataset with information drawn from the Hoover’s Inc. online platform, which includes information about companies NAICS codes, employee counts, and sales information.⁸⁰ Note that this analysis assumes that the firms performing potentially affected activities are also the firms performing activities in the future under the proposed NSPS. While likely true for many firms, this will not be the case for all firms.

The EPA matched owner/operators from the DrillingInfo dataset to companies in a database developed from a download of oil and gas companies in Hoover’s online database. The EPA matched as many records as possible. In the instances where the DrillingInfo owner/operator was not the highest level or company ownership, we recorded the highest level of owner as was identifiable in Hoovers. Linking these two datasets yields information on the NAICS, employee levels, and revenues of the owner/operators shown in the DrillingInfo dataset to have new or modified wells in 2012.

The EPA then used the NAICS codes associated with the matched owner/operators to determine which owner/operators should be considered to be small entities for this analysis, based on the SBA size standards above. That said, many DrillingInfo owner/operators had no match in Hoovers. Additionally, some Hoovers records lacked the information (employees or revenues, depending on the NAICS) needed to make a size determination. We initially classified these as an “unknown” size. See Table 7-8 for a summary of results of this matching exercise.

⁸⁰ The Hoover’s Inc. online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: <http://www.hoovers.com>.

Table 7-8 No. of Completions in 2012 by Preliminary Firm Size

Firm Size Performing Well Completions	No. of Firms	Number of Completions, 2012	
		Hydraulically Fractured or Re-fractured Oil Wells	All Completions
Small	1,000	3,300	12,000
Not Small	67	10,000	21,000
Unknown	1,100	750	6,000
Total	2,200	14,000	39,000

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts slightly lower than totals included in impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

Upon analysis of the firms of unknown size, the EPA observed that, on average, the firms of unknown size perform fewer well completions. For this reason, we made the observation that the firms of unknown size are more likely to be small than not small. To proceed with the analysis, we reclassified these firms as small, resulting in the distribution presented in the first two columns of Table 7-9.

Table 7-9 No. of Completions in 2012 by Firm Size

Firm Size Performing Well Completions	No. of Firms	No. of Completions, 2012	
		Hydraulically Fractured or Re-fractured Oil Wells	All Completions
Small	1,100 to 2,200	4,000	7,800 to 18,000
Not Small	66 to 67	10,000	15,000 to 21,000
Total	1,200 to 2,200	14,000	23,000 to 39,000

Note: consistent with the cost and emissions analysis, these 2012 completion counts do not include completions in states where there are state rules with similar requirements as the proposed rules. Counts slightly lower than totals included in impacts analysis base year estimates as some completions have no owner/operator recorded in the dataset. Sums may not total due to independent rounding.

The proposed NSPS provides an exclusion for low producing sites from the fugitive emissions requirements.⁸¹ A low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day.⁸² While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analyses in this IRFA, like the RIA, presents a “low” impact case and

⁸¹ In the preamble to the proposed rule, EPA is soliciting comment on excluding low production sites from the fugitive emissions program.

⁸² Natural gas production is converted to barrels oil equivalent using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas.

“high” impact case for fugitive emissions requirements at well sites. The low impact case excludes an estimate low production sites, based on the first month of production data from wells newly completed or modified in 2012. The high impact case includes these well sites. Table 7-9 presents the number of wells completed in the base year of 2012, where the range of wells under the fugitive emissions requirements reflects the range of the low and high impact cases. Note that while the number of firms potentially affected goes down substantially, the low production exclusion from fugitive emissions requirements does not affect the number of affected oil well completions.

7.3.4 Compliance Cost Impact Estimates

7.3.4.1 Methodology for Estimating Impacts on Small Entities

This section describes how we project the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels, how we estimate costs at the firm level from these activity estimates, and how we estimated sales for small entities when available data on sales are incomplete.

New and modified hydraulically fractured oil well completions and well sites in this IRFA are based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in this RIA. These growth rates are consistent with the drilling activity in the 2014 Annual Energy Outlook. These growth rates are applied to the 2012 base year estimates for each firm in the database. Table 7-10 and Table 7-11 present future year estimates of incrementally affected new and modified sources, in the low and high impact cases, respectively.

Table 7-10 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size, Low Impact Fugitive Emissions Case

Firm Size Performing Well Completions	No. of Incrementally Affected Sources, 2020			No. of Incrementally Affected Sources, 2025		
	Hydraulically Fractured or Re- fractured Oil	Gas Well	Oil Wells	Hydraulically Fractured or Re- fractured Oil	Gas Well	Oil Wells
	Wells	Sites	Sites	Wells	Sites	Sites
Small	4,100	980	3,400	4,200	6,900	20,000
Not Small	11,000	2,800	5,900	11,000	20,000	35,000
Total	15,100	3,780	9,300	15,200	26,900	55,000

Note: Sums may not total due to independent rounding. Assumes well sites have two wells apiece.

Table 7-11 No. of Incrementally Affected Sources in 2020 and 2025 by Firm Size, High Impact Fugitive Emissions Case

Firm Size Performing Well Completions	No. of Incrementally Affected Sources, 2020			No. of Incrementally Affected Sources, 2025		
	Hydraulically Fractured or Re-fractured Oil Wells	Gas Well Sites	Oil Wells Sites	Hydraulically Fractured or Re-fractured Oil Wells	Gas Well Sites	Oil Wells Sites
Small	4,100	1,900	7,900	4,200	13,000	48,000
Not Small	11,000	3,600	8,700	11,000	25,000	52,000
Total	15,100	5,500	16,600	15,200	38,000	100,000

Note: Sums may not total due to independent rounding. Assumes well sites have two wells apiece.

This approach assumes that no other firms perform potentially affected activities and firms performing these activities in 2012 will continue to do so in 2020 and 2025. Again, the analysis in this IRFA is meant to be illustrative of impacts on small entities. Exact predictions of future activities at the firm level is not possible.

Once the future year activities were estimated we allocated compliance costs across small entities based upon the costs estimated in the TSD and consistently with other analyses in this RIA. These cost estimates include estimates of revenue from natural gas recovery at the assumed value of \$4/Mcf in 2012 dollars, again consistent with other analyses in this RIA. For hydraulically fractured and re-fractured oil well completions, we assumed each small entity is required to perform RECs/completions and completions in the same proportions assumed in the TSD and RIA. We also assumed the same proportion would be exploratory or delineation wells as the TSD and RIA. Table 7-12 shows the distribution of compliance costs estimates across firm size, year, and whether the low production exemption is in place.

Table 7-12 Distribution of Estimated Compliance Costs¹ across Firm Size Classes

Firm Size	Annualized Compliance Costs (2012\$) Low Impact Case			Annualized Compliance Costs (2012\$) High Impact Case		
	No. of Firms	2020	2025	No. of Firms	2020	2025
Small	1,100	43,000,000	88,000,000	2,200	54,000,000	160,000,000
Not Small	66	100,000,000	190,000,000	67	110,000,000	240,000,000
Total	1,200	150,000,000	280,000,000	2,200	170,000,000	390,000,000

¹ Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. As described in Section 7.1.3, these provisions account for the large majority of the rule's potential impact in 2020 and 2025.

Note: sums may not total due to independent rounding.

In order to estimate the cost-to-sales ratio, we again combined information from Hoovers and the DrillingInfo databases. The Hoovers database has sales information for some, but not all, small entities estimated in this IRFA analysis to have impacts. To supplement the sales information, we estimated 2012 sales by multiplying 2012 oil and natural gas production levels reported in the DrillingInfo database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the same \$4/Mcf for natural gas.⁸³ For oil prices, we estimated revenues using two alternative prices, \$70/bbl and \$50/bbl. In the results, we call the case using \$70/bbl the “primary scenario” and the case using the \$50/bbl as the “low oil price scenario”.⁸⁴ In the instances where the 2012 production-derived revenues exceeded the Hoovers revenues, we replaced the Hoovers estimate with the production-derived estimate as more likely to be an accurate estimate of sales for 2012.

7.3.4.2 *Results*

This section presents results of the cost-to-sales ratio analysis for both the primary scenario and the low oil price scenario. In addition, we present both scenarios for the low and high impact cases with respect to the low production exemption from the well site fugitive emissions requirements.

⁸³ The U.S. Energy Information Administration’s 2015 Annual Energy Outlook projects 2020 Henry Hub natural gas prices to be \$4.88/MMBtu in its reference case and \$4.30/MMBtu in its “low oil” price case in 2013 dollars. Available at: <http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>. After adjusting to \$/Mcf (using the conversion of 1 MMBtu = 1.208 Mcf) in 2012 dollars (using the GDP-Implicit Price Deflator), these prices are \$4.94/Mcf in the reference case and \$4.35/Mcf in the low oil price case. Rounding down to \$4/Mcf would likely under-estimated sales.

⁸⁴ The 2015 Annual Energy Outlook projects wellhead oil prices to be \$75.16/bbl in its reference case and \$54.10/bbl in its “low oil” price case in 2013 dollars. Available at: <http://www.eia.gov/beta/aeo/#/?id=14-AEO2015>. After adjusting to 2012 dollars (using the GDP-Implicit Price Deflator), these prices are \$74.00/bbl in the reference case and \$53.27/bbl in the low oil price case. Rounding down to \$4/Mcf would likely under-estimated sales.

Table 7-13 Compliance Costs-to-Sales¹ Ratios (Fugitive Emissions Requirements Low Impact Case) across Firm Size Classes for Primary Scenario and Low Oil Price Scenario²

	2020 (Primary Scenario)		2020 (Low Oil Price Scenario)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	1,200	-	1,200	-
Greater than 1 percent	66	6%	77	7%
Greater than 3 percent	22	2%	25	2%

	2025 (Primary Scenario)		2025 (Low Oil Price Scenario)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	1,200	-	1,200	-
Greater than 1 percent	130	11%	160	13%
Greater than 3 percent	44	4%	53	5%

¹ Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. These provisions account for the large majority of the rule's potential impact in 2020 and 2025.

² In the main case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$70/bbl for crude oil. In the low oil price case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$50/bbl for crude oil.

Table 7-14 Compliance Costs-to-Sales¹ Ratios (Fugitive Emissions Requirements Low Impact Case) across Firm Size Classes for Primary Scenario and Low Oil Price Scenario²

	2020 (Primary Scenario)		2020 (Low Oil Price Scenario)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	2,100	-	2,100	-
Greater than 1 percent	270	13%	320	15%
Greater than 3 percent	120	6%	140	7%

	2025 (Primary Scenario)		2025 (Low Oil Price Scenario)	
	No. of Small Entities	% of Small Entities	No. of Small Entities	% of Small Entities
No. of Small Entities	2,100	-	2,100	-
Greater than 1 percent	710	33%	800	38%
Greater than 3 percent	370	17%	410	20%

¹ Compliance cost estimates here include only costs of requirements for hydraulically fractured or re-fractured oil well completions and well-site fugitive emissions. As described in Section 7.1.3, these provisions account for the large majority of the rule's potential impact in 2020 and 2025.

² In the main case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$70/bbl for crude oil. In the low oil price case, the wellhead prices are assumed to be \$4/Mcf for natural gas and \$50/bbl for crude oil.

Comparing Table 7-13 with Table 7-14, about 900 fewer small entities are estimated to be affected by the examined provision in the low impact fugitive emissions requirements case.

Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the high impact to low impact case without the exemption in place by approximately two-thirds. The percent impacted by greater than 3 percent is about double the percent affected by greater than 1 percent for each year of analysis in the primary and in the low oil price scenarios. Meanwhile, impacts greater than 1 percent and 3 percent increase in the low oil price scenarios, as would be expected. Also as expected the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS.

7.3.5 Caveats and Limitations

The analysis above is subject to a number of caveats and limitations, many of which we discussed in the presentation of methods and results. It is useful, however, to present a complete list of the caveats and limitation here.

- Because of data limitations, the analysis presented in the IRFA only examines impacts on requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While impacts from these requirements constitute a large proportion of the estimated impacts from the proposed NSPS, the omission of the cost requirements of other requirements leads to a relative under-estimation of the impacts on small entities. Also, the impacts from other requirements may affect firms that are not drilling wells, such as pipeline transmission firms.
- Not all owner/operators listed in the DrillingInfo database could be identified in the Hoovers database. These owner/operators tend to have developed relatively few new or modified wells in 2012. As a result, we assumed these were small entities, whereas these entities may actually be subsidiaries of larger enterprises. While the impacts estimates are not affected in the aggregate by this assumption, the assumption likely leads to an over-estimate of the impact on small entities for the provisions examined.
- The analysis assumes the same population of entities completing wells in 2012 are also completing wells in 2020 and 2025, according to growth rates developed for the entire sector. In the future, many of these firms will complete fewer or more wells, and other firms will complete wells. All of these firms combined may complete new or modified wells at higher or lower rates depending on economics and technological factors that are largely unpredictable.
- The approach used to estimate sales for the cost-to-sales might over-estimate or under-estimate sales depending upon the accuracy of the information in the underlying databases and the market prices ultimately faced in 2020 and 2025.

7.3.6 Projected Reporting, Recordkeeping and Other Compliance Requirements

The information to be collected for the proposed NSPS is based on notification,

performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of \$3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

7.3.7 *Related Federal Rules*

The New Source Performance Standards (NSPS) issued in 2012 are currently reducing VOC emissions from several sources in the oil and natural gas industry. In addition to the 2012

NSPS, there are two National Emission Standards for Hazardous Air Pollutants (NESHAP) rules that apply to certain equipment and processes in the oil and natural gas sector. These rules, listed below, address air toxics, primarily benzene, toluene, ethylbenzene and xylenes (collectively referred to as BTEX) and n-hexane. These two rules, which were updated concurrently with the 2012 NSPS, were promulgated under section 112 of the Clean Air Act and are codified in 40 CFR Part 63:

- Subpart HH – Crude Oil and Natural Gas Production (including processing); and
- Subpart HHH – Natural Gas Transmission and Storage.

Additionally, 40 CFR Part 98 Subpart W is a greenhouse gas reporting requirement that applies to petroleum and natural gas systems. Owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year from process operations, stationary combustion, miscellaneous use of carbonates, and other source categories are required to report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Owners or operators are required to collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

7.3.8 Regulatory Flexibility Alternatives

The Panel agrees that the EPA should explore regulatory alternatives and provide flexibility where appropriate. This flexibility can lessen impacts to small entities as well as entities not classified as small.

7.3.8.1 Oil Well Exemptions

SERs encouraged the EPA to exempt stripper wells, low pressure oil wells, and any well that requires artificial lift. SERs recommended that the EPA establish an overall applicability threshold based on production, emissions, well depth, well type (horizontal), well pressure, formation, or revenue to limit potential impact of future regulations on small entities.

The SERs offered several threshold alternatives to be applied to the oil well completion requirements which would significantly reduce compliance costs and burden to small entities that the SERs asserted would not affect gas recovery benefits. Some of these comments are described

below. Advocacy believes the EPA had a greater opportunity to advance the discussion by evaluating these alternatives through analysis of the available data. Advocacy further believes that there is enough information to conduct analysis of alternatives now. Advocacy notes that there are several types of thresholds that could be explored by the EPA, such as average production of nearby wells (by oil field, reservoir, or basin), well length or depth, and gas and water pressure characteristics. Advocacy encourages the EPA to do so in the future, in advance of proposal, to facilitate more informed and productive comments from the public which will lead to a better rulemaking.

The EPA has production and well characteristic data on thousands of oil wells through DrillingInfo, which aggregates all well data in the U.S. reported by operators to state agencies. In this database, the EPA could develop thresholds to target geographical areas or well characteristics with greater gas recovery potential than areas or characteristics where costs imposed would achieve little to no benefit. Advocacy believes the EPA should examine the data in DrillingInfo and the studies identified in the White paper for potential alternatives that minimize small entity costs, while achieving significant methane emission benefits. For example, Advocacy performed its own preliminary analysis of the DrillingInfo data, which led us to recommend a production threshold (see below). Advocacy believes the EPA also should consider the peer review and public comments on the white paper and reassess the size and diversity of the oil well completions in a more comprehensive fashion. Advocacy believes the EPA should have provided additional analysis since the publication of the white paper.

The EPA believes that it has reasonably analyzed the available data for this draft proposed rule, and sufficiently documented this analysis through the rule, the technical support document (TSD), and the SBREFA process. However, the EPA notes information gaps and has requested additional data and information through the public comment process.

Gas to Oil Ratio

Advocacy is concerned that the EPA estimate of ten tons of methane reduction per event for oil well completions may be significantly overestimated, based on its analysis of the 2012 Drilling Info database and SER comments. The 2012 analysis includes hydraulically fractured oil

well completions with GORs between 300 and 100,000, whereas the 2011 analysis was limited to GORs up to 12,500.

The Panel recommends that the EPA continue analyzing current data, and assess the alternatives mentioned by SERs. In an effort to contribute to the panel process, Advocacy analyzed the EPA data provided. Advocacy found that geographical patterns and well characteristics exist in the data to suggest common sense thresholds. While a 300 gas to oil ratio (GOR) threshold provides some relief for small entities, it is problematic because GOR is not known at time of fracturing when a completion takes place. Advocacy further recommends that the EPA develop a scheme based on the well characteristics of nearby wells in the basin or reservoir to provide an estimate for the GOR parameter. However, the location of the well, and the drill direction are known parameters that could be used. In concert with these other considerations, Advocacy recommends the EPA consider a GOR cutoff closer to 900, as one SER suggested.

The EPA believes that a gas-to-oil ratio (GOR) of 300 scf of gas per barrel of oil produced is an appropriate threshold for facilities to be subject to the well completion provisions of the NSPS. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance⁸⁵. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field. The EPA is soliciting comment on whether a GOR of 300 is the appropriate applicability threshold. Additionally, the EPA understands that GOR is not known at the time of well completion, and is soliciting comment on whether the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well.

Low Production Wells

When mapping average daily associated gas of 90 Mcf or above (isolating stripper wells) using county level data, Advocacy found that most (85%) of these greater gas recovery oil well

⁸⁵ On February 24, 2015, API submitted a comment to the EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator.

completions occur in about a third of the counties analyzed. Advocacy contends that there are potentially large areas that could be exempted from this requirement without forgoing significant methane emission reduction, or at least phased in to allow time to design proper data collection. For example, PIOGA comments report an average gas volume of only 74 MCFD in Pennsylvania stripper oil wells in contrast to Pennsylvania stripper gas wells averaging 532 MCFD.

The EPA understands that low production wells have inherently low emissions from well completions and many are owned and operated by small businesses. However, the EPA recognizes that identification of these wells prior to completion events is difficult, especially considering that drilling of a low production well may be unintentional and may be infrequent, but production may nevertheless proceed due to economic reasons. The EPA is soliciting comment and information on emissions associated with low production wells, characteristics of these wells and supporting information that would help owners/operators and enforcement personnel identify these wells prior to completion.

Because of these preliminary findings about low production and a lack of evidence that there will be sufficient gas recovery, the Panel recommends that the EPA further analyze and consider exempting low production wells (with an average daily production of less than 15 barrel equivalents) from a REC or combustion requirement during oil well completions.

Vertical Wells

According to a SER comment, vertical wells lack sufficient wellhead pressure or quantity of gas to be separated during completion. Advocacy recommends that since the white papers laid the foundation to the materials prepared for the Panel, the EPA should revisit the information learned through this process, especially as it relates to the specific characteristics of vertical wells. Therefore, as a regulatory alternative, Advocacy recommends the EPA consider exempting vertical wells from oil well completion requirements.

The EPA clarifies that both the 2014 white paper analysis of oil well completions and DrillingInfo data analysis include vertical wells that are hydraulically fractured. However, the EPA understands that there are certain physical well characteristics that may inhibit the operation of a separator, and notes that the rule does not require RECs where their use is not feasible.

However, the EPA has not seen sufficient data to support the characterization that a separator will not be able to function for all or the majority of vertical wells that are hydraulically fractured. However, the EPA recommends soliciting comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional).

Low Pressure Oil Wells

Advocacy recommends that “low pressure wells” should be categorically exempt and could be based on a threshold sales line/gathering line of approximately 250 psi or a simple water gradient formula of 0.465 psi/foot. The emissions associated with these types of wells are so low that even if a separator can be operated for some short period of time, the value of gas does not exceed the cost associated with bringing equipment to the site. As the SERs indicated, these oil completion requirements can be very costly on small firms, particularly with respect to small production wells. The expected gas recovery benefits from oil well completions are expected to be a small fraction of the benefits obtained by the gas wells under the current version of the NSPS rule.

The EPA is aware that oil wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC. In the 2012 NSPS the EPA did not require low pressure gas wells to perform REC, but operators were required to control those well completions using combustion. However, the EPA recommends soliciting comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional). The EPA defines low pressure wells as a well with reservoir pressure and true vertical well depth such that $0.445 \times \text{reservoir pressure (in psia)} - 0.038 \times \text{vertical well depth (in feet)} - 67.578 \text{ psia}$ is less than the flow line pressure at the sales meter. The EPA recommends soliciting comment on whether this definition is appropriate for low pressure oil wells.

Substitution of Combustion over Green Completion / REC Requirements

Advocacy recommends that the EPA substitute flaring for the green completion requirement (REC), in addition to the consideration of thresholds. This alternative is much more cost-effective, and particularly important for small firms to have a lower cost alternative that achieves a 95% reduction. The PIOGA comments also stated that the use of RECs would adversely impact the productivity and longevity of the stripper oil wells. Alternatively, the EPA could require larger firms to perform the RECs, while allowing smaller firms (using a firm revenue cutoff or other small business size indicator) to combust the remaining gas.

The EPA recommends that RECs be implemented on oil wells, except where their use is not feasible (e.g., technically infeasible for a separator to function, availability of gathering lines). Compared to combustion alone, the EPA believes that the combination of REC and combustion will maximize the recovery of natural resources and minimize venting to the atmosphere. However, the EPA notes that although the flaring in lieu of RECs may be less costly, flaring contributes secondary environmental impacts, nuisance impacts to nearby communities and complicates compliance for owners/operators.

Phase – In for Oil Well Completion Requirements

The Panel recommends that the EPA consider phasing in the well completion requirement over a period of years. The Panel agrees that the EPA solicit comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule in the event of potential shortage of REC equipment and, if not, how a phase in could be structured. The Panel agrees that a phased in approach could be structured to provide for control of the potentially highest emitting wells first, with other wells being included at a later date. The Panel recommends that the EPA solicit comment on whether GOR of the well and production level of the well should be bases for the phasing of requirements for RECs, and if so, what an appropriate threshold for phase-in should be.

7.3.8.2 Fugitives - Leak Detection Methods

SERs encouraged the EPA to allow a variety of leak detection technologies, including Method 21, AVO, and soap testing. The EPA asserts that use of OGI can reduce the amount of

time necessary to conduct fugitive emissions monitoring since multiple fugitive emissions components can be surveyed simultaneously, reducing the cost of identifying fugitive emissions compared to alternative leak detection technologies that require a manual screening of each fugitive emissions component. Advocacy recommends the EPA propose Method 21 or OGI as allowable alternatives. The EPA contends that while Method 21 is lacking because it does not allow the detection of malfunctioning equipment that may not be the focus of the survey, and it is not as cost-effective as OGI, the Panel recommends the EPA solicits comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold. The EPA notes that the proposed rule would allow the use either OGI or Method 21 for resurvey because the resurvey would focus solely on ensuring repairs resolved the leak at the individual component.

7.3.8.3 *Fugitives – Survey Frequency*

SERs recommended leak surveys be conducted no more than once per year. Advocacy has questions about the costs of repair and the emission reductions that be achieved through increased survey frequency which Advocacy believes the EPA was unable to address satisfactorily. Advocacy urges the EPA to improve the record basis for its emission reduction estimates and the cost of repairs for Method 21 and OGI, in order to permit more informed comment on the alternatives. Advocacy believes the EPA was unable to adequately explain the basis for the different repair costs vs. frequency for Method 21 and OGI⁸⁶, or the basis for the 40/60/80% emission reductions based on increasing survey frequency from annual to quarterly.⁸⁷

The EPA determined that semiannual monitoring will result in identification and repair of significant fugitive emissions from components, and that using OGI, an operator can survey multiple fugitive emissions components simultaneously reducing the cost of identifying fugitive emissions. Additionally, if fugitive emissions are detected at less than one percent of the fugitive

⁸⁶At this time, the EPA shows annual repair costs that increase linearly with survey frequency for OGI, but are static for Method 21. For Method 21, the EPA applied the same repair costs whether the frequency was annual, semiannual or quarterly. For OGI, EPA used double the repair costs for semiannual, and four times the repair costs for quarterly. Advocacy believes this could lead to a bias in an evaluation of one method vs. the other.

⁸⁷Advocacy was also disappointed that EPA was unable to share with the SERs more information that would have help the SERs formulate their recommendations (including some of the issues addressed above). The EPA believes the background documents created for the SERs were thorough and accurate, and transparently presented the data and data sources used in the analysis for the proposed rule. The documents are additionally available for public review in the docket for the proposed rule.

emission components at a well site during two consecutive semiannual monitoring surveys, the proposed rule allows for the monitoring survey frequency for that well site to be reduced to annually. Advocacy had no information upon which to base a recommendation related to the proportion of leaking components, but supports analysis of such an approach. Advocacy also recommends that the EPA provide more analysis and factual foundation for the record to allow commenters to provide more informed advice.

The Panel agrees that the EPA should solicit comment on an alternate proposal option based on an initial annual survey frequency. The Panel recommends the EPA solicit comment on the appropriateness of semiannual monitoring frequency and the proposed provisions for increasing and decreasing the monitoring frequency.

7.3.8.4 Fugitive Emissions at Well Sites

The Panel recommends not requiring fugitive emission surveys at well production sites, unless there are potentially significant sources of emissions, such as storage tanks. The Panel further agrees that well sites with low production wells (i.e., a well with an average daily production of 15 barrel equivalents or less) should not require fugitive emission surveys.

7.3.8.5 Fugitive Emissions at Production and Processing Sites, and Compressor Stations at Transmission and Storage Sites

Under Subpart W, gas production and processing sites and compressor stations at transmission and storage sites are required to annually monitor for fugitive emissions and to quantify such emissions. The only missing regulatory component to be considered is to add a requirement to repair detected leaks as appropriate. This is already covered by the May 2015 INGAA Directed Inspection and Maintenance voluntary Program for Transmission and Storage Compressor Stations. The EPA is already considering this program⁸⁸ in its recent request for comment on the voluntary methane reduction program for the oil and gas sector. Advocacy recommends that the EPA retain the annual requirement, as Advocacy believes this requirement is entirely duplicative of a fugitives survey requirement, and consider the specific repair

⁸⁸ US EPA. Natural Gas STAR Methane Challenge Program: Proposed Framework, slide 17 states, “EPA has received, and is considering, a proposal to structure BMP coverage of natural gas transmission and storage compressor stations as a Directed Inspection and Maintenance Program.”

requirements for repair identification and repair delay in the DI&M voluntary program as the components of a mandatory program. Furthermore, the EPA's most recent evaluation of the survey cost-effectiveness shows that annual surveys are more cost-effective than semi-annual surveys. Therefore, the Panel recommends the EPA propose options based on semi-annual and annual monitoring. Advocacy recommends that the EPA should also consider allowing each facility to tailor the specific program to site-specific considerations, rather than apply the same requirements uniformly to each plant. The EPA recognizes that Subpart W serves as an emissions inventory, while this rule's intent is to minimize pollution. The EPA believes that the additional survey with semiannual OGI monitoring provides additional leak detection, and cost-effective emission reductions. The EPA recognizes that fugitive emissions may be underestimated based on emerging studies and will continue to evaluate these studies. The Panel recommends the EPA propose an alternate option based on an initial annual frequency for well sites. The Panel recommends that the EPA continue to consider the INGAA DI&M recommendations for leak repairs in the rulemaking.

7.3.8.6 Well Site Compressors

SERs encouraged the EPA to exempt well site compressors as they are typically rental units and have irregular service time, and regulation could be cost prohibitive. The Panel agrees that emissions from well site compressors were extremely low and that cost of control of these compressors would not be reasonable. The Panel recommends that the EPA maintain the exemption for well site compressors.

7.3.8.7 Pneumatic Pumps

SERs encouraged the EPA to exempt pneumatic pumps if controls were not already in place. The Panel agrees that combustion controls should only be required if a control is required for another source. The Panel recommends the EPA exempt pneumatic pumps without a control device already located on site.

7.3.8.8 Reciprocating Compressors

The Panel supports the EPA proposal to require replacement of rod packing every 26,000 hours or 3 years in lieu of monitoring hours. The Panel also supports the further consideration of the alternative developed in the Natural Gas Star Program for condition-based maintenance.

Advocacy recommends the EPA should carefully study the INGAA recommendations for condition-based maintenance for rod packing as an alternative to maintaining or replacing rod packing on a prescribed schedule.⁸⁹

The EPA recommends that the draft proposed rule retain the rod packing replacement options and the option to route the rod packing emissions to a process through a closed vent system under negative pressure.

7.3.8.9 Centrifugal Compressors

Advocacy recommends that the EPA reconsider the requirement of requiring capture and combustion of gas emissions from wet seal compressors whose emissions don't differ that much from dry seal compressors, according to INGAA. Advocacy is concerned that requiring combustion at compressor stations would prove to be unpopular with the surrounding neighborhood. This requirement would convert an otherwise unobtrusive structure in the neighborhood into a constant source of combustion and a source of air pollution.

The EPA recommends retaining the requirement for a 95% emissions reduction from wet seal compressors, which can be achieved by capturing and routing the emissions utilizing a cover and closed vent system to a control device, or routing the captured emissions to a process. The EPA notes that dry seal compressors are not affected facilities in the draft proposed rule because of their inherently low emissions. The EPA also notes that many of these combustors are enclosed and will be innocuous to the surrounding neighborhood. In addition, the gas liberated from the barrier fluid during degassing is very clean natural gas, and the combustor is required under the NSPS to burn cleanly with no visible emissions.

7.3.8.10 Pneumatic Controllers

The Panel agrees with the EPA's recommendation that low-bleed pneumatic controllers be required in place of high-bleed controllers (i.e., natural gas bleed rate not to exceed 6 scfh). The Panel recommends the rule continue to treat low-bleed pneumatic controllers as not affected facilities except at natural gas processing plants, where zero bleed pneumatic controllers are considered BSER.

⁸⁹ See INGAA comment on 40 CFR 60 Part OOOO. EPA-HQ-OAR-2010-0505-4104

7.3.8.11 Recordkeeping and Reporting for High Bleed Controllers

The EPA recommends that owners and operators continue to be permitted to use high bleed controllers needed for specific functional purposes, but require recordkeeping to document the justification. The Panel agrees that recordkeeping and reporting requirements should be minimized wherever possible. However, the Panel notes that a recordkeeping and reporting requirement that asks companies to justify and document their need for continuous high bleed devices has caused many companies to reevaluate their need for and change out unnecessary high bleed pneumatic controllers.

7.3.8.12 Liquids Unloading

Based on the information and data available to the EPA during development of the 2012 NSPS, the Panel agrees that control of liquids unloading emissions is not appropriate at this time. However, the EPA believes that the emissions from liquids unloading operations are significant, and so the Panel recommends that the EPA continue to study this issue and solicit information and data supporting demonstrated control technologies or management practices for reducing these emissions.

7.4 Employment Impact Analysis

In addition to addressing the costs and benefits of the proposed rule, the EPA has analyzed the impacts of this rulemaking on employment, which are presented in this section.⁹⁰ While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate given continued interest in the employment impact of regulations such as this proposed rule. Executive Order 13563, states, “Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation.”

⁹¹ A discussion of compliance costs, including reporting and recordkeeping requirements, is included in Section 3 of this RIA. This analysis uses detailed engineering information on labor

⁹⁰ The employment analysis in this RIA is part of EPA’s ongoing effort to “conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]” pursuant to CAA section 321(a).

⁹¹ Executive Order 13563 (January 21, 2011). *Improving Regulation and Regulatory Review. Section 1. General Principles of Regulation*, Federal Register, Vol. 76, Nr. 14, p. 3821.

requirements for each of the control strategies identified in this proposed rule in order to estimate partial employment impacts for affected entities in the oil and gas industry. These bottom-up, engineering-based estimates represent only one portion of potential employment impacts within the regulated industry, and do not represent estimates of the *net* employment impacts of this rule. First, this section presents an overview of the various ways that environmental regulation can affect employment. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is valid and informative. The section concludes with partial employment impact estimates that rely on engineering-based information for labor requirements for each of the control strategies identified by the proposed rule.

7.4.1 Employment Impacts of Environmental Regulation

From an economic perspective labor is an input into producing goods and services; if a regulation requires that more labor be used to produce a given amount of output, that additional labor is reflected in an increase in the cost of production. Moreover, when the economy is at full employment, we would not expect an environmental regulation to have an impact on overall employment because labor is being shifted from one sector to another. On the other hand, in periods of high unemployment, employment effects (both positive and negative) are possible.

For example, an increase in labor demand due to regulation may result in a short-term net increase in overall employment as workers are hired by the regulated sector to help meet new requirements (e.g., to install new equipment) or by the environmental protection sector to produce new abatement capital resulting in hiring previously unemployed workers. When significant numbers of workers are unemployed, the opportunity costs associated with displacing jobs in other sectors are likely to be higher. And, in general, if a regulation imposes high costs and does not increase the demand for labor, it may lead to a decrease in employment. The responsiveness of industry labor demand depends on how these forces all interact. Economic theory indicates that the responsiveness of industry labor demand depends on a number of factors: price elasticity of demand for the product, substitutability of other factors of production, elasticity of supply of other factors of production, and labor's share of total production costs. Berman and Bui (2001) put this theory in the context of environmental regulation, and suggest

that, for example, if all firms in the industry are faced with the same compliance costs of regulation and product demand is inelastic, then industry output may not change much at all.

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing environmental regulations. When a regulation is promulgated, one typical response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. On the other hand, the closure of plants that choose not to comply – and any changes in production levels at plants choosing to comply and remain in operation - occur after the compliance date, or earlier in anticipation of the compliance obligation. Environmental regulation may increase revenue and employment in the environmental technology industry. While these increases represent gains for that industry, they translate into costs to the regulated industries required to install the equipment.

Environmental regulations support employment in many basic industries. Regulated firms either hire workers to design and build pollution controls directly or purchase pollution control devices from a third party for installation. Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment—much like they hire workers to produce more output. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Currently in most cases there is no scientifically defensible way to generate sufficiently reliable estimates of the employment impacts in these intermediate goods sectors.

Berman and Bui (2001) demonstrate using standard neoclassical microeconomics that environmental regulations have an ambiguous effect on employment in the regulated sector. The theoretical results imply that the effect of environmental regulation on employment in the regulated sector is an empirical question and both sets of authors tested their models empirically using different methodologies. Berman and Bui (2001) developed an innovative approach to examine how an increase in local air quality regulation that reduces nitrogen oxides (NO_x)

emissions affects manufacturing employment in the South Coast Air Quality Management District (SCAQMD), which incorporates Los Angeles and its suburbs. During the time frame of their study, 1979 to 1992, the SCAQMD enacted some of the country's most stringent air quality regulations. Using SCAQMD's local air quality regulations, Berman and Bui identify the effect of environmental regulations on net employment in the regulated industries.⁹² The authors find that "while regulations do impose large costs, they have a limited effect on employment" (Berman and Bui, 2001, p. 269). Their conclusion is that local air quality regulation "probably increased labor demand slightly" but that "the employment effects of both compliance and increased stringency are fairly precisely estimated zeros, even when exit and dissuaded entry effects are included" (Berman and Bui, 2001, p. 269).⁹³

While there is an extensive empirical, peer-reviewed literature analyzing the effect of environmental regulations on various economic outcomes including productivity, investment, competitiveness as well as environmental performance, there are only a few papers that examine the impact of environmental regulation on employment, but this area of the literature has been growing. As stated previously in this RIA section, empirical results from Berman and Bui (2001) suggest that new or more stringent environmental regulations do not have a substantial impact on net employment (either negative or positive) in the regulated sector. Similarly, Ferris, Shadbegian, and Wolverton (2014) also find that regulation-induced net employment impacts are close to zero in the regulated sector. Furthermore, Gray et al (2014) find that pulp mills that had to comply with both the air and water regulations in the EPA's 1998 "Cluster Rule" experienced relatively small and not always statistically significant, decreases in employment. Nevertheless, other empirical research suggests that more highly regulated counties may generate fewer jobs than less regulated ones (Greenstone 2002, Walker 2011). However, the methodology used in these two studies cannot estimate whether aggregate employment is lower or higher due to more stringent environmental regulation, it can only imply that relative employment growth in some sectors differs between more and less regulated areas. List *et al.* (2003) find some evidence that this type of geographic relocation, from more regulated areas to less regulated areas may be occurring. Overall, the peer-reviewed literature does not contain evidence that environmental

⁹² Berman and Bui include over 40 4-digit SIC industries in their sample.

⁹³ Including the employment effect of exiting plants and plants dissuaded from opening will increase the estimated impact of regulation on employment.

regulation has a large impact on net employment (either negative or positive) in the long run across the whole economy.

While the theoretical framework laid out by Berman and Bui (2001) still holds for the industries affected under these emission guidelines, important differences in the markets and regulatory settings analyzed in their study and the setting presented here lead us to conclude that it is inappropriate to utilize their quantitative estimates to estimate the employment impacts from this proposed regulation. In particular, the industries used in these two studies as well as the timeframe (late 1970's to early 1990's) are quite different than those in this proposed NSPS. Furthermore, the control strategies analyzed for this RIA include implementing RECs, reducing fugitive emissions, and reducing emissions from pneumatic controllers, pumps, and reciprocating and centrifugal compressors, which are very different than the control strategies examined by Berman and Bui.⁹⁴ For these reasons we conclude there are too many uncertainties as to the transferability of the quantitative estimates from Berman and Bui to apply their estimates to quantify the employment impacts within the regulated sectors for this regulation, though these studies have usefulness for qualitative assessment of employment impacts.

The preceding sections have outlined the challenges associated with estimating net employment effects in the regulated sector and in the environmental protection sector. These challenges make it very difficult to accurately produce net employment estimates for the whole economy that would appropriately capture the way in which costs, compliance spending, and environmental benefits propagate through the macro-economy. Given the difficulty with estimating national impacts of regulations, the EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the evaluation of costs, benefits, and economic impacts associated with environmental regulation, the EPA has formed a panel of experts as part of the EPA's Science Advisory Board (SAB) to advise the EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.⁹⁵ Once the EPA receives guidance from this panel it will carefully

⁹⁴ More detail on how emission reductions expected from compliance with this rule can be obtained can be found in Section 3 of this RIA.

⁹⁵ For further information see:

<http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument>

consider this input and then decide if and how to proceed on economy-wide modeling of employment impacts of its regulations.

7.4.2 *Labor Estimates Associated with Proposed Requirements*

Section 2 of the RIA, in Tables 2-17 and 2-18, presents background information on employment and wages in the oil and natural gas industry. As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in six oil and natural gas-related NAICS codes from 1990 to 2013.⁹⁶ The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 314,000 in 1999, but rebounding to a 2013 peak of 620,000. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry. From 1990 to 2013, average wages for the oil and natural gas industry have increased. Table 2-18 shows real wages (in 2012 dollars) from 1990 to 2013 for the NAICS codes associated with the oil and natural gas industry.

The focus of this part of the analysis is on labor requirements related to the compliance actions for the proposed rule, of the affected entities within the oil and natural gas sector. We do not estimate any potential changes in labor outside of the affected sector, and, due to data and methodology limitations, we do not estimate net employment impacts for the affected sector, apart from the partial estimate of the labor requirements related to control strategies. This analysis estimates the labor required to the install, operate, and maintain control equipment and activities, as well as to perform new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce output negative production externality (i.e., emissions) a firm often has to reduce production, many of the emission controls required by the proposed NSPS will simultaneously increase production and reduce negative externalities. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions. To the extent, however, that these

⁹⁶ NAICS 211111, 21112, 213111, 213112, 486110, and 486210.

rules may require unprofitable investments for some operators, there is a possibility that these producers decrease output in response and create downward pressure on labor demand, both in the regulated sector and on those sectors using natural gas as an input. This RIA does not include quantified estimates of these potential adverse effects on the labor market due to data and theoretical challenges, as described above.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because the EPA does not currently have this information. The labor requirements analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in Chapter 3 of this RIA includes estimates of the labor requirements associated with implementing the regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

The results of this employment analysis of the proposed NSPS are presented in Tables 7-16 through Table 7-19 for 2020 and 2025 for individual sources regulated under this proposal. Table 7-20 presents summary-level labor impacts for all sources. The tables break down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. The labor information is based upon the cost analysis presented in the TSD that supports this proposal, based upon analysis presented in the RIA developed for the 2012 NSPS and NESHAP Amendments for the Oil and Natural Gas Sector (U.S. EPA, 2012). In addition, for the proposed NSPS, reporting and recordkeeping requirements were estimated for the entire rule rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates the EPA submitted as part of its Information Collection Request (ICR), the estimated costs of which are included in the cost estimates presented in Chapter 3.

Table 7-15 presents estimates labor requirements for hydraulically fractured oil well completions. The REC and completion combustion requirements are associated with certain new and existing oil well completions. While individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed annually. Because of these reasons, we assume the REC-related labor requirements are annual.

The per-unit estimates of one-time labor requirements associated with implementing RECs and completion combustion are drawn from the labor requirements estimated for implementing RECs on hydraulically fractured well completions in EPA (2012). However, the labor requirements in that report were based upon a completion that is assumed to last seven days (218 hours per completion for a REC or 22 hours labor per completion for completion combustion). In this analysis, completion events for hydraulically fractured oil wells are assumed to last three days, so we multiply the seven-day requirements by $3/7$ (93 hours per completion for a REC or 9 hours labor per completion for completion combustion).

Table 7-15 Estimates of Labor Required to Comply with Proposed NSPS for Hydraulically Fractured Oil Well Completions, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor Est. (hrs)	Per-unit Annual Labor Est. (hrs)	Total One-Time Labor Estimate (hrs)	Total Annual Labor Estimate (hrs)	One-time FTE	Annual FTE
2020								
Hydraulically Fractured and Re-fractured Oil Well Completions								
Development Oil Wells	Reduced Emission Completion	6,903	0	93	0	644,937	0	310
Wildcat and Delineation Oil Wells	Completion Combustion	7,773	0	9	0	73,289	0	35
Total		14,676	N/A	N/A	0	718,227	0	345
2025								
Hydraulically Fractured and Re-fractured Oil Well Completions								
Development Oil Wells	Reduced Emission Completion	6,901	0	93	0	644,751	0	310
Wildcat and Delineation Oil Wells	Completion Combustion	8,066	0	9	0	76,055	0	37
Total		14,967	N/A	N/A	0	720,806	0	347

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per-unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-16 and Table 7-17 present estimates of labor requirements for the low and the high impacts cases for fugitive emissions. Consistent with the cost estimates for fugitive emissions presented in the TSD, we estimate labor associated with company-level activities and activities at field sites. Company-level activities include one time activities such as planning the company's fugitive emissions program and annual requirements such as reporting and recordkeeping. Field-level activities include semiannual inspection and repair of leaks as proposed. It is important to note, however, that the compliance costs estimates for leak inspection were based upon an estimate of the costs to hire a contractor to provide the inspection service, but the source providing this information does not have a breakdown of the labor component of the rental cost. As a result, the labor requirements for the fugitives program are likely underestimates.

Table 7-16 Estimates of Labor Required to Comply with Proposed NSPS for Fugitive Emissions, Low Impact Case, 2020 and 2025

		Projected No. of Incr. Affected Units	Per-unit One- time Labor (hrs)	Per-unit Annual Labor (hrs)	Total One- Time Labor (hrs)	Total Annual Labor (hrs)	One- time FTE	Annual FTE
Emissions Source/ Emissions Control								
2020								
Well Sites								
Company-level Activities	Semiannual Monitoring/	605	118.0	0.0	71,352	0	34	0
Site-level Activities	Maintenance	13,303	0.0	14.1	0	187,717	0	90
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	259	0.0	108.7	0	28,141	0	14
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	6	0.0	108.7	0	652	0	0
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	15	0.0	212.9	0	3,193	0	2
Total		13,583	N/A	N/A	104,392	219,702	50	106
2025								
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	139,108	5.4	14.1	0	1,962,940	0	944
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	1,554	0.0	108.7	0	168,844	0	81
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	36	0.0	108.7	0	3,911	0	2
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	90	0.0	212.9	0	19,160	0	9
Total		140,788	N/A	N/A	151,469	2,154,855	73	1,036

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-17 Estimates of Labor Required to Comply with Proposed NSPS for Fugitive Emissions, High Impact Case, 2020 and 2025

Emissions Source/	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor (hrs)	Per-unit Annual Labor (hrs)	Total One-Time Labor (hrs)	Total Annual Labor (hrs)	One-time FTE	Annual FTE
2020								
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	22,080	0.0	14.1	0	311,569	0	150
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	259	0.0	108.7	0	28,141	0	14
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	6	0.0	108.7	0	652	0	0
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	15	0.0	212.9	0	3,193	0	2
Total		22,360	N/A	N/A	151,469	343,555	73	165
2025								
Well Sites								
Company-level Activities	Semiannual Monitoring/	1,004	118.0	0.0	118,429	0	57	0
Site-level Activities	Maintenance	139,108	5.4	14.1	0	1,962,940	0	944
Gathering and Boosting Stations								
Company-level Activities	Semiannual Monitoring/	259	118.0	0.0	30,562	0	15	0
Site-level Activities	Maintenance	1,554	0.0	108.7	0	168,844	0	81
Transmission Compressor Stations								
Company-level Activities	Semiannual Monitoring/	6	118.0	0.0	708	0	0	0
Site-level Activities	Maintenance	36	0.0	108.7	0	3,911	0	2
Storage Compressor Stations								
Company-level Activities	Semiannual Monitoring/	15	118.0	0.0	1,770	0	1	0
Site-level Activities	Maintenance	90	0.0	212.9	0	19,160	0	9
Total		140,788	N/A	N/A	151,469	2,154,855	73	1,036

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Most labor required for fugitive emissions is needed at well sites in the field, which number in the thousands. Note that the labor requirements estimates increase from 2020 to 2025 as the number of sites regulated under the proposed NSPS accumulates.

Table 7-18 presents labor requirement estimates for reciprocating and centrifugal compressors. Like the estimates for completions, the per unit labor estimates were based on EPA (2012). As relatively little labor is required for reciprocating compressors and relatively few affected centrifugal compressors are expected in the future, the estimates of both one-time and on-going labor requirements for compressor requirements are minimal.

Table 7-18 Estimates of Labor Required to Comply with Proposed NSPS for Reciprocating and Centrifugal Compressors, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor Est. (hrs)	Per-unit Annual Labor Est. (hrs)	Total One-Time Labor Estimate (hrs)	Total Annual Labor Estimate (hrs)	One-time FTE	Annual FTE
2020								
Compressors								
Reciprocating	Monitoring and Maintenance	67	1	1	67	67	0.0	0.0
Centrifugal	Route to Control	1	355	0	355	0	0.2	0.0
Total		68	N/A	N/A	422	67	0.2	0.0
2025								
Compressors								
Reciprocating	Monitoring and Maintenance	402	1	1	67	402	0.0	0.2
Centrifugal	Route to Control	6	355	0	355	0	0.2	0.0
Total		408	N/A	N/A	422	402	0.2	0.2

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-19 presents the labor requirement estimates for requirements applying to pneumatic controllers and pneumatic pumps. Note that pneumatic controllers have no one-time or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent

the regulation (U.S. EPA, 2012). In this instance, we assume the incremental labor requirements are zero. Meanwhile, we are currently unable to estimate the labor associated with pneumatic pump control activities.

Table 7-19 Estimates of Labor Required to Comply with Proposed NSPS for Pneumatic Controllers and Pumps, 2020 and 2025

Emissions Source	Emissions Control	Projected No. of Incr. Affected Units	Per-unit One-time Labor Est. (hrs)	Per-unit Annual Labor Est. (hrs)	Total One-Time Labor Estimate (hrs)	Total Annual Labor Estimate (hrs)	One-time FTE	Annual FTE
2020								
Pneumatic Controllers	Emissions Limit	210	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	2,962	N/A	N/A	N/A	N/A	N/A	N/A
2025								
Pneumatic Controllers	Emissions Limit	1,260	0	0	0	0	0	0
Pneumatic Pumps	Route to Control	17,772	N/A	N/A	N/A	N/A	N/A	N/A

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-20 presents the labor estimates across all emissions sources. Two main categories contain the majority of the labor requirements for the proposed NSPS: implementing reduced emissions completions (REC) at hydraulically fracture oil well completions and fugitive emissions detection and repair at well sites. The up-front labor requirement to comply with the proposed NSPS is estimated at 73 FTEs in 2020 and in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 530 FTEs in 2020 and 1,400 FTEs in 2025. We note that this type of FTE estimate cannot be used to identify the specific number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 7-20 Estimates of Labor Required to Comply with Proposed NSPS, 2020 and 2025

Emissions Source	Projected No. of Incrementally Affected Units (2020)	Total One- Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time FTE	Annual FTE
2020					
Hydraulically Fractured and Re-fractured Oil Well Completions	15,000	0	720,000	0	350
Fugitive Emissions	14,000 to 22,000	100,000 to 150,000	220,000 to 340,000	50 to 73	110 to 170
Pneumatic Controllers	210	0	0	0	0
Pneumatic Pumps	3,000	N/A	N/A	N/A	N/A
Reciprocating Compressors	67	67	67	0	0
Centrifugal Compressors	1	360	0	0	0
Reporting and Recordkeeping Requirements	All	0	40,000	0	19
Total	31,000 to 40,000	100,000 to 150,000	980,000 to 1,100,000	50 to 73	470 to 530
2025					
Hydraulically Fractured and Re-fractured Oil Well Completions	15,000	0	720,000	0	350
Fugitive Emissions	86,000 to 140,000	100,000 to 150,000	1,400,000 to 2,200,000	50 to 73	660 to 1,000
Pneumatic Controllers	1,300	0	0	0	0
Pneumatic Pumps	18,000	N/A	N/A	N/A	N/A
Reciprocating Compressors	400	67	400	0	0
Centrifugal Compressors	6	360	0	0	0
Reporting and Recordkeeping Requirements	All	0	120,000	0	58
Total	120,000 to 180,000	100,000 to 150,000	2,200,000 to 3,000,000	50 to 73	1,100 to 1,400

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Rounded to two significant digits. Totals may not sum due to independent rounding.

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