6.7 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale and sludge.) Based upon currently available information it is anticipated that flowback water will not contain levels of NORM of significance, whereas production brine is known to contain elevated NORM levels. Radium-226 is the primary radionuclide of concern from the Marcellus.

Elevated levels of NORM in production brine (measured in picocuries/liter or pCi/L) may result in the buildup of pipe scale containing elevated levels of radium (measured in pCi/g). The amount and concentration of radium in the pipe scale would depend on many conditions, including pressures and temperatures of operation, amount of available radium in the formation, chemical properties, etc. Because the concentration of radium in the pipe scale cannot be measured without removing or disconnecting the pipe, a surrogate method is employed, conducting a radiation survey of the pipe exterior. A high concentration of radium in the scale would result in an elevated radiation exposure level at the pipe's exterior surface (measured in mR/hr) and can be detected with a commonly used survey instrument. The Department of Health would require a radioactive materials license when the radiation exposure levels of accessible piping and equipment are greater than 50 microR/hr (μR/hr). Equipment that exhibits dose rates in excess of this level will be considered to contain processed and concentrated NORM for the purpose of waste determinations.

Oil and gas NORM occurs in both liquid (production brine), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the highest concentrations of NORM are in production brine, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (pipe scale and sludge) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also wastes from the treatment of production brines may contain concentrated

NORM and therefore may require controls to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with 6 NYCRR § 380.4.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (Table 6.30). Radon gas, which under most circumstances is the main human health concern from NORM, is produced by the decay of radium-226, which occurs in the uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Table 6.30 - Radionuclide Half-Lives

Radionuclide	**Half-life**	**Mode of Decay**
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of production brine (>109 billion bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

In NYS the disposal of processed and concentrated NORM in the form of pipe scale or water treatment waste is subject to regulation under Part 380. Because disposal of Part 380 regulated waste is prohibited in Part 360 regulated solid waste landfills, this waste would require disposal in out-of-state facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select RCRA C facilities and low-level radioactive waste disposal sites.

6.8 Socioeconomic Impacts[134]

This section provides a discussion of the potential socioeconomic impacts on the Economy, Employment, and Income (Section 6.8.1); Population (Section 6.8.2); Housing (Section 6.8.3); Government Revenues and Expenditures (Section 6.8.4); and Environmental Justice (Section 6.8.5). A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS.

To estimate the socioeconomic impacts associated with the use of high-volume hydraulic fracturing techniques for extracting natural gas, several assumptions must be made about the amount of natural gas development that would occur, the expected rate of development, the length of time over which that development would occur, and the distribution of this development throughout the state.

For the purposes of this SGEIS, the expected rate of development is measured by the number of wells constructed annually. Two different levels of development are analyzed – a low development scenario, and an average development scenario. These development scenarios were developed by the Department based on information the Department had requested from the Independent Oil & Gas Association of New York (IOGA-NY). IOGA-NY started with an estimated average rate of development based on the following assumptions:

[134] Section 6.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Approximately 67% of the area covered by the Marcellus and Utica shale is developable;
- Approximately 90% of wells would be horizontal wells, with an average of 160 acres/well; and
- Approximately 10% of wells would be vertical wells, with an average of 40 acres/well.

For the low rate of development, DEC assumed a rate of 25% of IOGA-NY's estimated average rate of development.

Table 6.31 provides a highlight of the major assumptions for each of these scenarios. In both scenarios, the maximum build-out of new wells is assumed to be completed in Year 30. Under the low development scenario, a total of 9,461 horizontal wells and 1,071 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). Under the average development scenario a total of 37,842 horizontal wells and 4,284 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). The high development scenario, which is analyzed in the Economic Assessment Report, assumes a total of 56,508 horizontal and 6,273 vertical wells are constructed at maximum build-out (e.g., Year 30).

Analysis of the high development scenario is not included in this socioeconomic section of the SGEIS in order to be conservative in assessing the positive potential economic benefits of high-volume hydraulic fracturing in New York State. The high development scenario was used as the conservative assumption of activity for all other sections of this SGEIS.

Economic realities, including diminishing marginal returns associated with drilling wells further from the fairway in less than ideal locations, and the exclusion of high-volume hydraulic fracturing wells from certain sensitive locations, would make it highly unlikely that the maximum build-out under the high development scenario would occur. Therefore, only the low and average development scenarios are discussed throughout this section.

These development scenarios are designed to provide order-of-magnitude estimates for the following socioeconomic analysis and are in no way meant to forecast actual well development levels in the Marcellus and Utica Shale reserves in New York State. These scenarios should be viewed as a "best estimate" of the range of possible amounts of development that could occur in New York State.

Table 6.31 - Major Development Scenario Assumptions (New August 2011)

	Scenarios	
	Low	**Average**
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	9,461	37,842
Vertical	1,071	4,284
Total	**10,532**	**42,126**
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	371	1,484
Vertical	42	168
Total	**413**	**1,652**

Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year "ramp-up" period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end. This assumption, which does not significantly affect the socioeconomic impact analysis, was used to remain consistent with other sections of the SGEIS. In actuality, well development would more likely gradually ramp up, reach a peak, and then gradually ramp down as fewer and fewer wells were completed. However, this curve would not necessarily be smooth.

It is unlikely that new well construction would occur under a steady, constant rate. Economic factors such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of the state and nation would all affect the yearly rate of well construction and the overall level of development of the gas reserves. The actual track of well construction would likely be much more cyclical in nature than as described in the following sections.

The average development scenario should be viewed as the upper boundary of possible development, while the low development scenario should be viewed as the likely lower boundary of possible development. As shown in Table 6.31, the maximum number of new wells developed in a year under the low development scenario is 371 horizontal and 42 vertical wells, and the maximum number of new wells developed in a year under the average development scenario is 1,484 horizontal and 168 vertical wells.

Each newly constructed well is assumed to have an average productive life of 30 years. For example, wells constructed in Year 1 are assumed to still be producing in Year 30, and wells constructed in Year 10 are assumed to produce until Year 40. Because of the assumption of a 30-year development period, wells constructed in Year 30 are assumed to be productive until Year 60. Assuming a 30-year development period and a 30-year production life for each well, the number of productive wells in New York State would be expected to grow until Year 30, at which point, the number of productive wells would peak. After Year 30, with no new wells being constructed, the number of wells in production would begin to decline. Because the number of annual wells approved and developed each year is different for the two development scenarios, the peak number of operating wells at Year 30 also differs for each scenario.

Under both development scenarios, natural gas production in New York State would occur from Year 1 until Year 60, with Year 30 having the maximum number of wells in production. After Year 30, producing wells would gradually decline until Year 60, at which time it is assumed that production stops.

As discussed in Section 2.4.13, no site-specific project locations are being evaluated in the SGEIS. Therefore, for purposes of analysis, three distinct regions were identified within the area where potential drilling may occur in order to take a closer look at the potential impacts at the regional and local levels. The three regions were selected to evaluate differences between areas with a high, moderate, and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

- Region A: Broome County, Chemung County, and Tioga County;
- Region B: Delaware County, Otsego County; and Sullivan County; and
- Region C: Cattaraugus County and Chautauqua County

This analysis is not intended to imply that impacts would occur only in these three regions. Impacts would occur at the local and regional levels wherever high-volume hydraulic fracturing wells are constructed. The actual locations of these wells have not yet been determined, and they could be constructed wherever there is low-permeable shale. Similar to the development scenarios described above, the representative regions are designed to give a range of possible socioeconomic impacts. Therefore, the results of the local and regional analysis should also be seen as order-of-magnitude estimates for the range of possible impacts. Further descriptions of the regions are provided in Section 2.4.11.

6.8.1 Economy, Employment, and Income

The following discusses the potential impacts on the economy, employment and income for New York State, and the local areas within each of the three regions (Regions A, B and C).

6.8.1.1 New York State

Economy and Employment

Development of low-permeability natural gas reservoirs in the Marcellus and Utica shale by high-volume hydraulic fracturing would be expected to have a significant, positive impact on the economy of New York State. Construction and operation of the new natural gas wells are expected to increase employment, earnings, and economic output throughout the state. According to statistics collected and calculations made by the Marcellus Shale Education and Training Center (the Center), in Pennsylvania, an average natural gas well using the high-volume hydraulic fracturing technique requires 410 individuals working in 150 different occupations. The manpower requirements to drill a single well were calculated to be 11.53 full-time equivalent (FTE) construction workers (Marcellus Shale Education and Training Center 2009).

A full-time equivalent worker is defined as one worker working eight hours a day for 260 days a year, or several workers working a total of 2,080 hours in a year. While the Center found that up to 410 individuals are required to build one well, only 11.53 FTE workers were needed. Typically, a high-volume hydraulic fracturing well is constructed over a 3- to 4-month period, and many of the individuals and occupations are needed for only a very short duration. Therefore, to accurately assess the economic impacts of constructing a high-volume hydraulic fracturing well, the FTE workforce was considered.

The Center also calculated the work force requirements for operating a well as 0.17 FTE workers, or approximately 354 person hours per year. In other words, approximately 1 FTE worker is required to operate and maintain every 6 wells in production (Marcellus Shale Employment and Training Center 2009). Unlike the construction workforce that drills the well within a few months and is finished, the operational workforce is required for the productive life of the well. For the purposes of this analysis, a 30-year productive life has been assumed for each well drilled. Therefore, for every new well drilled, 0.17 FTE workers are employed for 30 years.

In its study, the Marcellus Shale Employment and Training Center did not differentiate between the labor requirements needed to drill a horizontal versus a vertical well. Typically, it is much more costly and labor-intensive to drill a high-volume hydraulic fracturing horizontal well than it is to drill a high-volume hydraulic fracturing vertical well. Therefore, in an effort to be conservative and not overstate the positive economic impacts, a factor was applied to the 11.53 FTE figure for vertical wells in the estimates used for this analysis. This factor was calculated using the average depth of a vertical well compared to the average depth of a high-volume hydraulic-fracturing horizontal well. The resulting ratio of 0.2777 was applied to the 11.53 FTE labor requirement to estimate the overall labor requirements of a vertical well.

Using the workforce requirement figures developed by the Marcellus Shale Employment and Training Center and the two development scenarios described above, the expected impacts on employment and earnings from high-volume hydraulic fracturing were projected for New York State as a whole.

As shown in Table 6.32, annual direct construction employment is directly related to the number of wells drilled in a given year. At the maximum well construction rate assumed for each development scenario, total annual direct construction employment is predicted to range from 4,408 FTE workers under the low development scenario to 17,634 FTE workers under the average development scenario. These employment figures correspond to the annual construction of 413 horizontal and vertical wells under the low development scenario and 1,652 horizontal and vertical wells under the average development scenario. In order to reach the full build-out potential used in the scenarios, it is assumed that construction employment and new well construction would remain at these levels for 20 years, starting in Year 10 (see Table 6.32).

The maximum direct production employment under each development scenario is also shown in Table 6.32. These figures represent the peak production year (Year 30), when the maximum build-out potential has been reached before any of the wells have stopped producing. The preceding and the following years all would have fewer production workers. At the peak, production employment would be expected to range from 1,790 FTE workers under the low development scenario to 7,161 FTE workers under the average development scenario (Table 6.32).

Table 6.32 - Maximum Direct and Indirect Employment Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Direct Employment Impacts		
Construction Employment[1]	4,408	17,634
Production Employment[2]	1,790	7,161
Indirect Employment [3]	7,293	29,174
Total Employment Impacts	13,491	53,969
Total Employment as a Percent of New York State 2010 Labor Force	0.2%	0.7%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

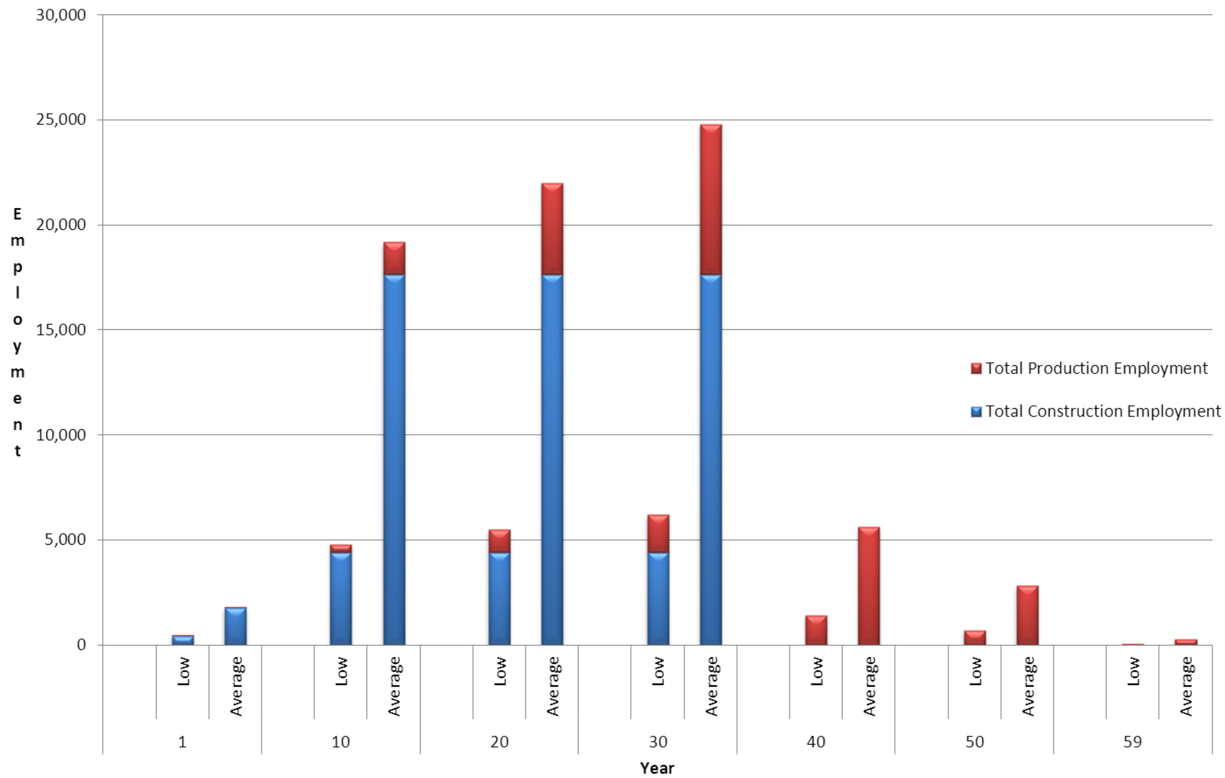
1 These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

2 These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production employment for all other years.

3 Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

Figure 6.12 illustrates the projected direct employment in New York State that would result from implementation of each development scenario over the 60-year time frame. The figure shows how construction and production employment levels are expected to vary, with peak direct employment occurring in Year 30.

Figure 6.12 – Projected Direct Employment in New York State Resulting from Each Development Scenario (New August 2011)

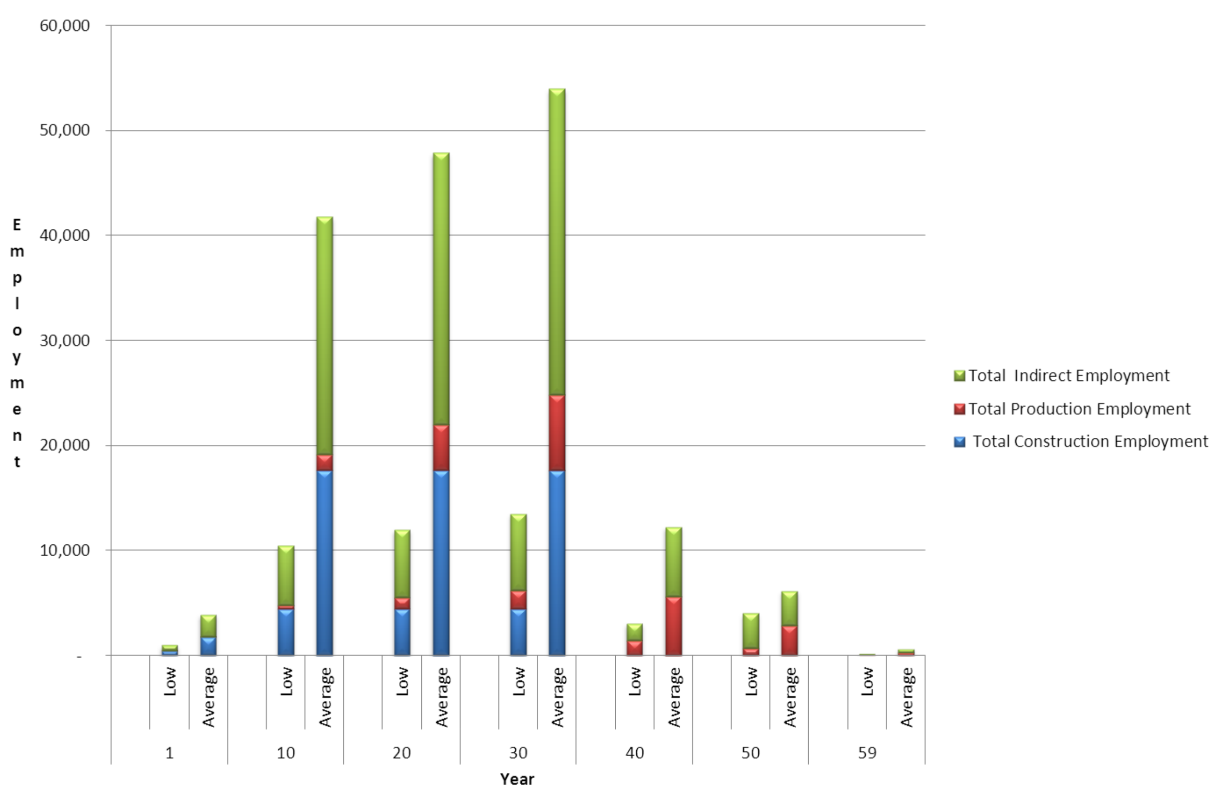


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from suppliers in New York State, the overall demand for goods and services in the state would expand. Revenues at the wholesale and retail outlets and service providers within the state would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the state, thus "multiplying" the positive economic impacts of the original increase in construction/production spending. These "multiplier" effects would continue on until all of the original funds have left New York State's economy through either taxes or savings, or through purchases from outside the state.

Indirect employment impacts are expected to range from an additional 7,293 FTE workers under the low development scenario to an additional 29,174 FTE workers under the average development scenario. These annual figures represent the year with the maximum employment (Year 30). The years before and after this date would have less direct and indirect employment.

In total, at peak employment years, state approval of drilling in the Marcellus and Utica Shales is expected to generate between 13,491 and 53,969 direct and indirect jobs, which equates to 0.2% and 0.6%%, respectively, of New York State's 2010 total labor force, depending on the level and intensity of development that occurs (see Table 6.32). Figure 6.13 graphically illustrates the projected total employment in New York State that would result from each development scenario. As shown on the figure, total employment levels would be highest in Year 10 through Year 30. Once new well construction ends in Year 31, the direct and indirect employment would be greatly reduced.

Figure 6.13 - Projected Total Employment in New York State Resulting from Each Development Scenario (New August 2011)



The majority of these indirect jobs would be concentrated in the construction, professional, scientific, and technical services; real estate and rental/leasing; administrative and waste management services; management of companies and enterprises; and manufacturing industries.

Income

The increase in direct and indirect employment would have a positive impact on income levels in New York State. Table 6.33 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 through Year 30), total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30, the year that the maximum number of operational workers are assumed to be employed.

Table 6.33 - Maximum Direct and Indirect Annual Employee Earnings Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Direct Earnings Impacts		
Construction Earnings[1]	$298.4	$1,193.8
Production Earnings[2]	$121.2	$484.8
Indirect Employee Earnings Impacts[2,3]	$202.3	$809.2
Total Employee Earnings Impacts	$621.9	$2,487.8
Total Employee Earnings as a Percent of New York State's 2009 Total Wages	0.1%	0.5%

Source: U.S. Bureau of Economic Analysis 2011a; NYDOL 2009.

1 These figures represent the maximum annual change in construction earnings under each scenario and correspond to construction earnings in Years 10 - 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

2 These figures represent the maximum annual production earnings and indirect employee earnings under each development scenario. These figures correspond to operations earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation earnings for all other years.

3 Type I direct earnings multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

As described above, the construction and production activities would also generate significant indirect economic impacts. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. These figures equate to increases of between 0.1% and 0.5% of the total wages and salaries earned in New York State during 2009 (see Table 6.33).

Owners of the subsurface mineral rights where wells are drilled will also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or more of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, can result in significant increases in income. Signing bonuses/bonus bids also can provide significant additional income to property owners.

6.8.1.2 Representative Regions

As noted above, three representative regions were selected to show the range of possible socioeconomic impacts that could occur at the local and regional levels. This analysis in no way is meant to imply that impacts will occur only in these three regions.

For purposes of this analysis, it is assumed that 50% of all new well construction would occur in Region A (Chemung, Tioga, and Broome counties); 23% would occur in Region B (Otsego, Delaware, and Sullivan counties); 5% would occur in Region C (Chautauqua and Cattaraugus counties); and the remaining 22% of new well construction would occur in the rest of New York State. Geological data on the extent and thickness of the low-permeability shale in New York State, including the Marcellus Shale and Utica Shale fairways, were the basis for these assumptions.

Table 6.34 details the major assumptions for each development scenario for each representative region. In all cases, total development is assumed to be reached at Year 30. As shown in the table, Region A is anticipated to receive the majority of the new well construction. The analysis of Region A is designed to show the upper bound of potential regional economic impacts. Under the low development scenario, a total of 5,281 new wells would be constructed in the counties of Tioga, Chemung, and Broome. Under the average development scenario, a total of 21,067 new wells would be constructed in Region A. The projected maximum number of new wells developed per year in Region A would range from 207 to 826 wells, depending on the development scenario considered. The projected maximum number of new wells developed per year in Region B would range from 2,425 to 9,690 wells, depending on the development scenario (see Table 6.34).

In contrast, Region C is assumed to experience a much smaller level of well development than Region A or Region B. The analysis of Region C is designed to show the lower bound of potential regional economic impacts. Under the low development scenario, a total of 534 new wells would be constructed in Region C. Under the average development scenario, a total of 2,095 new wells would be constructed in Region C. The maximum number of new wells constructed each year in Region C is assumed to be 21 wells under the low development scenario and 82 wells under the average development scenario. The remaining 22% of the development would occur in the rest of the state (see Table 6.34).

Table 6.34 - Major Development Scenario Assumptions for Each Representative Region (New August 2011)

	Scenarios	
	Low	**Average**
Region A		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	4,743	18,923
Vertical	538	2,144
Total	5,281	21,067
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	186	742
Vertical	21	84
Total	207	826
Region B		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,170	8,697
Vertical	255	993
Total	2,425	9,690
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	85	341
Vertical	10	39

	Scenarios	
	Low	**Average**
Total	95	380
Region C		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	483	1,888
Vertical	51	207
Total	534	2,095
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	19	74
Vertical	2	8
Total	21	82
Rest of State		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,065	8,334
Vertical	227	940
Total	2,292	9,274
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	81	327
Vertical	9	37
Total	90	364

Economy and Employment

The proposed approval of the use of high-volume hydraulic fracturing technique would have a significant positive economic impact at the regional and local levels. Using the same methodology described above for the statewide analysis, the FTE labor requirements needed to construct and operate these wells were estimated for each region. Table 6.35 provides the maximum direct and indirect employment impacts that are predicted to occur under each development scenario for each region.

In Region A, which is used to define an upper boundary of the regional socioeconomic impacts, it is projected that direct construction employment would range from 2,204 FTE construction workers at the maximum employment levels under the low development scenario to 8,818 FTE construction workers at the maximum employment levels under the average development scenario. The new production employment in the region is expected to range from 895 to 3,581 FTE production workers per year.

In contrast, employment impacts are not anticipated to be as large in Region C, which is used to define a lower boundary for the regional socioeconomic impacts. At the maximum employment levels under the low development scenario, an estimated 221 new FTE constructions workers and 90 new FTE production workers would be needed for drilling and maintaining the new natural gas wells. These figures would increase to 882 new FTE construction workers and 358 new FTE production workers under the average development scenario (see Table 6.35).

Table 6.35 - Maximum Direct and Indirect Employment Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Employment[1]	2,204	8,818
Production Employment[2]	895	3,581
Indirect Employment Impacts[3]	650	2,600
Total Employment Impacts	3,749	14,999
Total Employment as a Percentage of Region A's 2010 Total Labor Force	2.3%	9.3%
Region B		
Direct Employment Impacts		
Construction Employment[1]	1,014	4,056
Production Employment[2]	412	1,647
Indirect Employment Impacts[3]	191	762
Total Employment Impacts	1,617	6,465
Total Employment as a Percentage of Region B's 2010 Total Labor Force	1.8%	7.3%
Region C		
Direct Employment Impacts		
Construction Employment[1]	221	882
Production Employment[2]	90	358
Indirect Employment Impacts[3]	66	263
Total Employment Impacts	377	1,503
Total Employment as a Percentage of Region C's 2010 Total Labor Force	0.4%	1.4%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

1 These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

2 These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation employment for all other years.

3 Separate Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II), were used for each region to estimate the indirect employment impacts.

Figure 6.14, Figure 6.15, and Figure 6.16 illustrate the projected direct employment in each representative region that would result from implementation of each development scenario over the 60-year time frame. The figures show how construction and production employment levels are expected to vary, with the peak direct employment occurring in Year 30.

Figure 6.14 - Projected Direct Employment in Region A Resulting from Each Development Scenario (New August 2011)

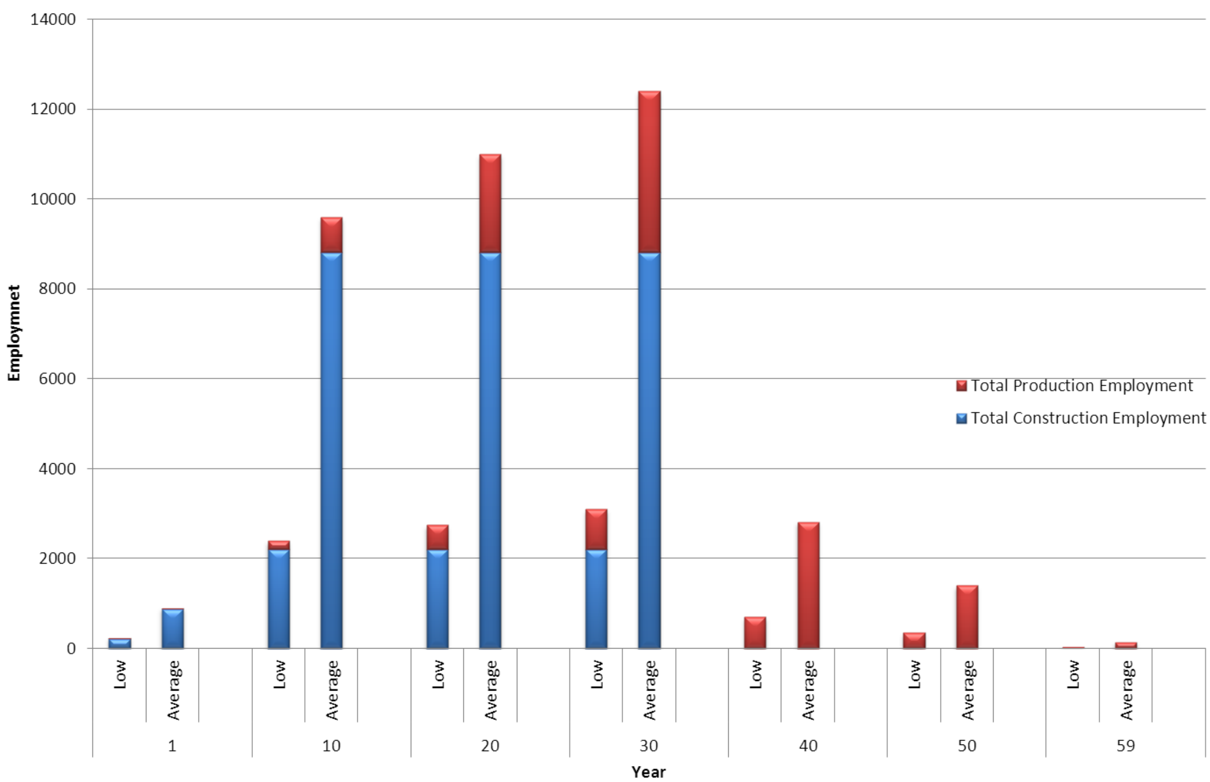


Figure 6.15 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

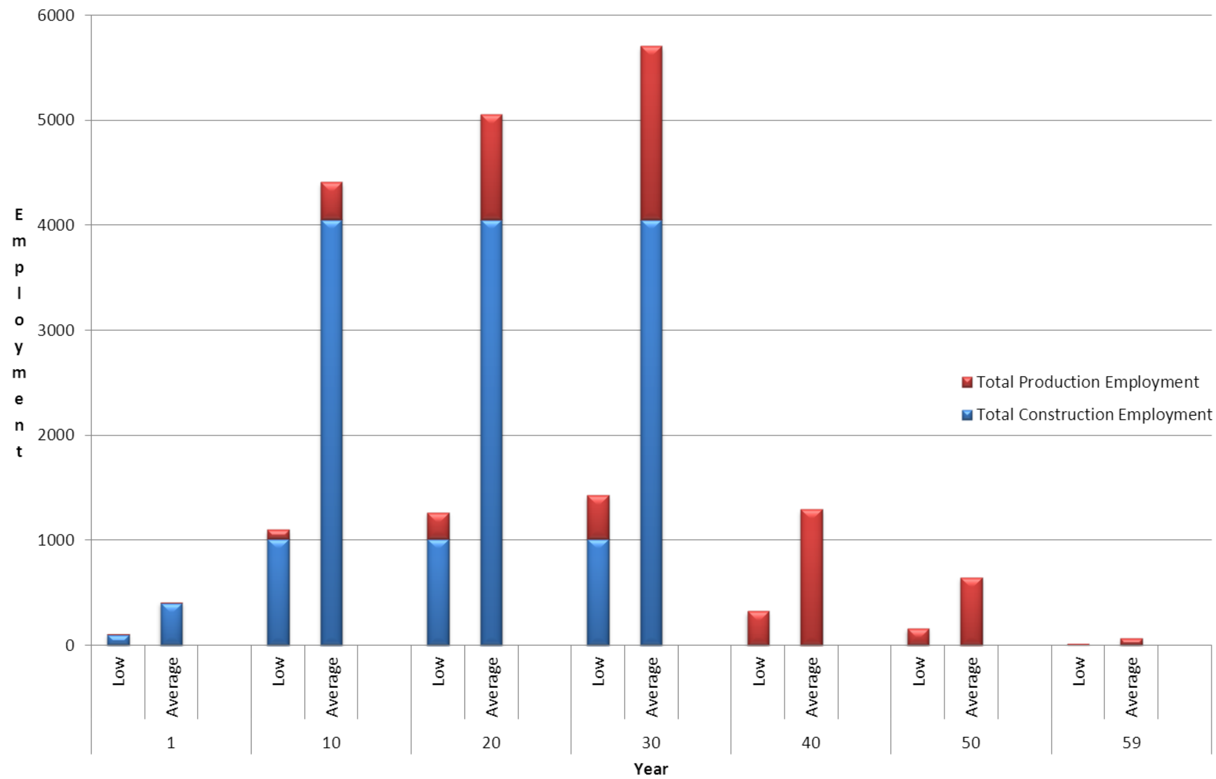
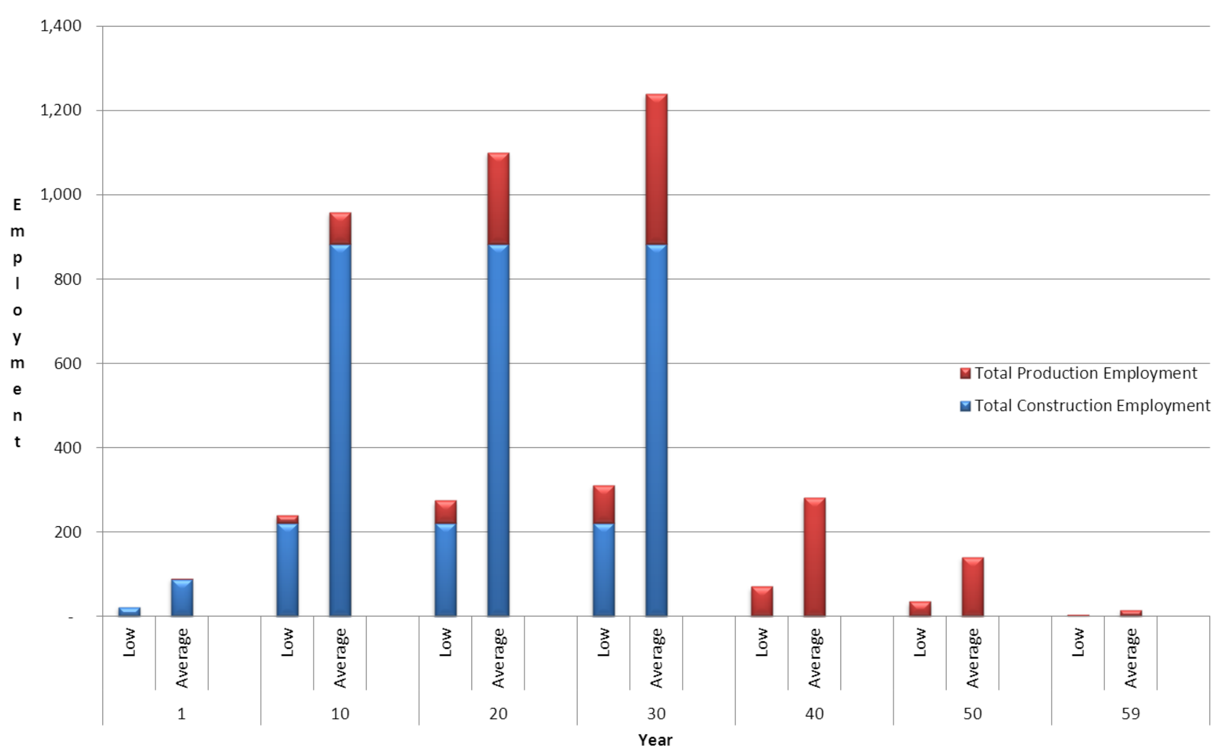


Figure 6.16 - Projected Direct Employment in Region C Resulting from
Each Development Scenario (New August 2011)



As described previously for the statewide impacts, in addition to the direct employment impacts, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from regional suppliers, the overall demand for goods and services in the region would expand. Revenues at the region's wholesale and retail outlets and service providers would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the region, thus "multiplying" the positive economic impacts of the original increase in construction/operation spending. These "multiplier" effects would continue on until all of the original funds have left the region's economy through either taxes or savings, or through purchases from outside the region.

Indirect employment impacts are expected to range from a high of 650 to 2,600 indirect workers in Region A to a low of 66 to 263 indirect workers in Region C, depending on the development scenario. Direct employment multipliers of 1.4977 for Region A, 1.3272 for Region B, and 1.4657 for Region C for the oil and gas extraction industry were used in this analysis (U.S. Bureau of Economic Analysis 2011b; 2011c; 2011d). In contrast, New York State as a whole had a direct employment multiplier of 2.1766 for the oil and gas extraction industry (U.S. Bureau of Economic Analysis 2011a).

The employment and earnings multipliers in these regions are much smaller than in New York State as a whole, underscoring the fact that portions of these study areas do not have as well-developed, self-sufficient, and diverse economies as the state as a whole. In particular, the low multipliers reflect the fact that much of the goods and services that would be needed to construct and operate the new wells would be purchased outside the regions.

However, it can be expected that as the natural gas industry matures in these regions, more local suppliers and service providers would enter the markets and be able to respond to the natural gas industry's needs. As time goes by, a larger portion of the indirect economic impacts would remain in the region, further stimulating the local economies.

Figure 6.17, Figure 6.18, and Figure 6.19 graphically illustrate the projected total employment in Region A, Region B, and Region C, respectively, that would result from each development scenario. As shown on the figures, total employment levels would be greatest in Year 10 through Year 30. Once new well construction ends in Year 30, the projected direct and indirect employment would be greatly reduced.

Figure 6.17 – Projected Total Employment in Region A Under Each Development Scenario (New August 2011)

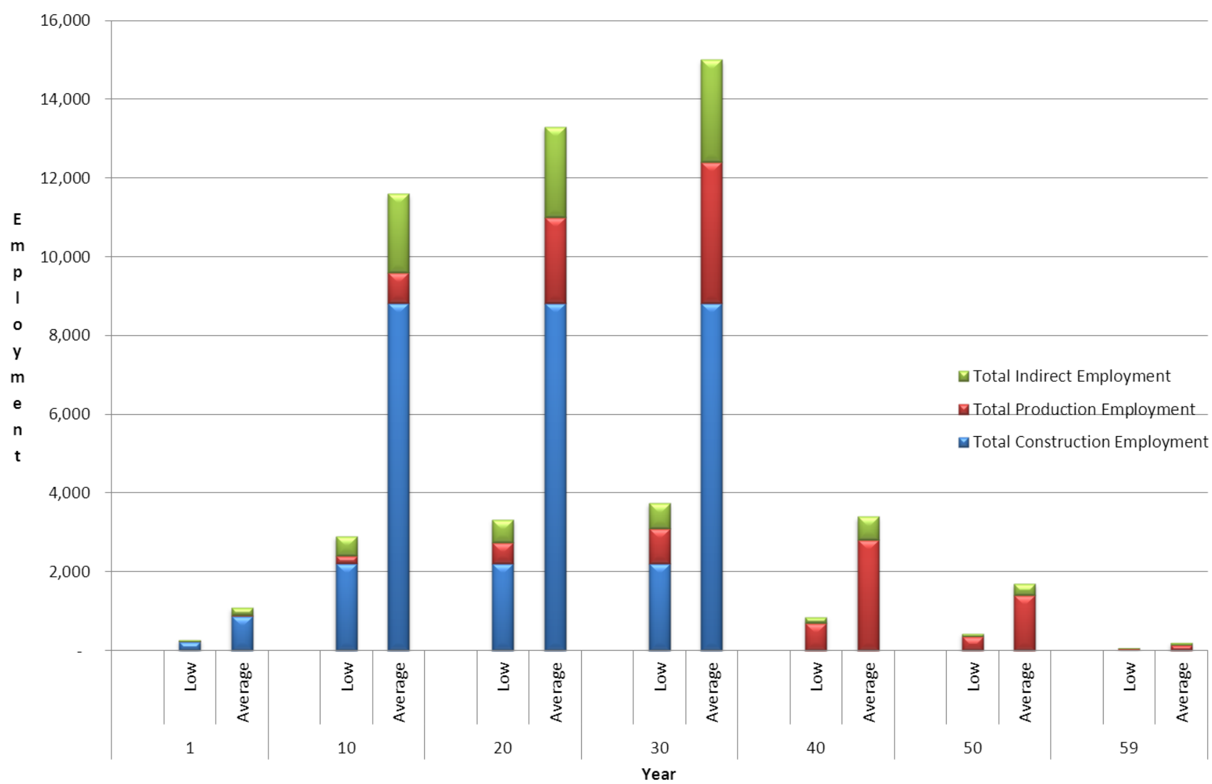


Figure 6.18 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

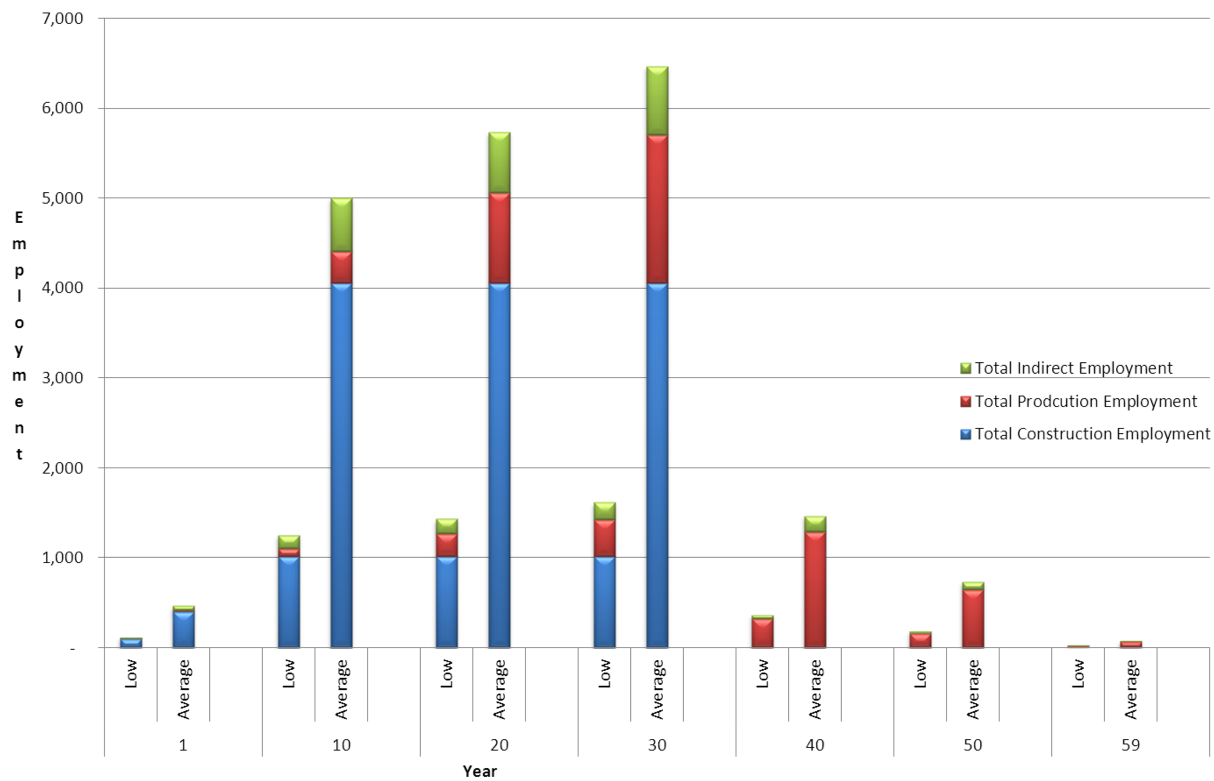
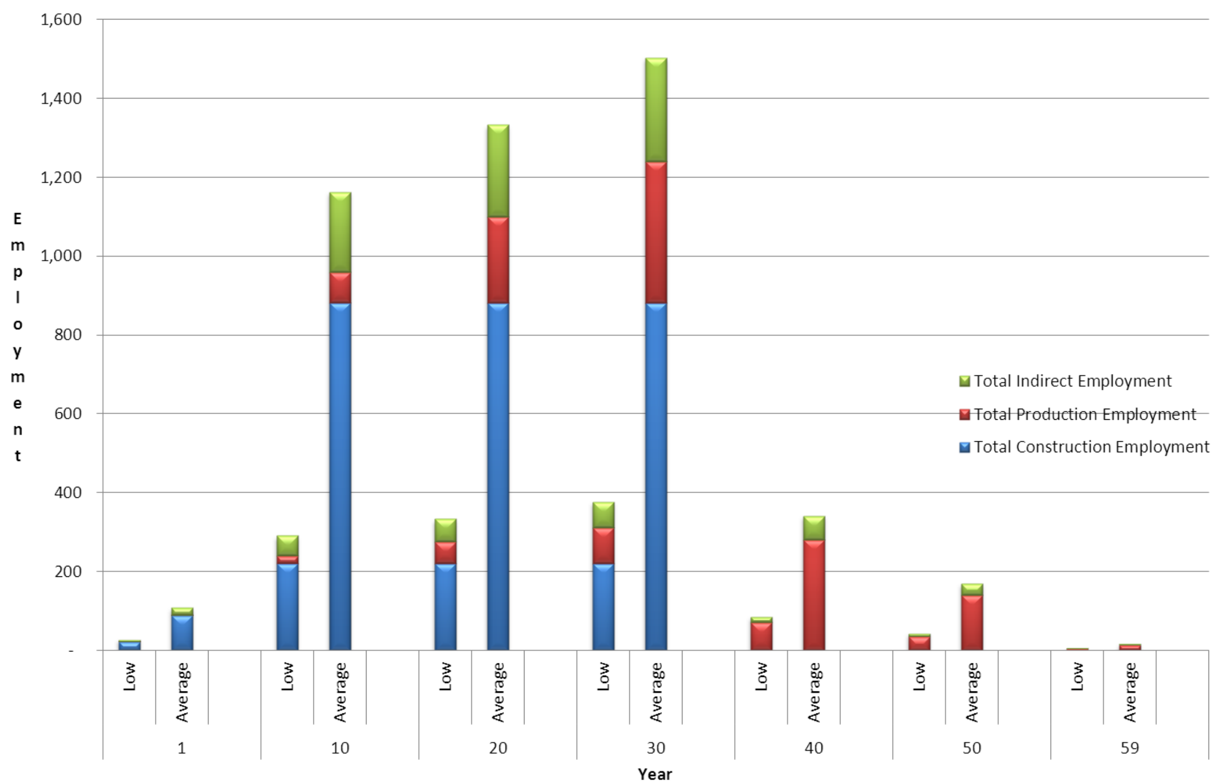


Figure 6.19 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeable shale is located. Many geological and economic factors would interact to determine the exact location that wells would be drilled. The location of productive wells would determine the distribution of impacts.

In some regions in the state where drilling is most likely to occur, the increases in employment may be so large that these regions may experience some short-term labor shortages. The increase in direct and indirect employment related to the natural gas extraction industry could drive wage rates up in the areas in the short term and make it more difficult for existing industries to recruit and retain qualified workers. In addition, the increase in wage rates could have a short-term, negative impact on existing industries as it would increase their labor costs. These potential short-term labor impacts would be less severe because specialized labor from outside the region would likely be required for certain jobs, and the existence of employment opportunities would cause the migration of workers into the region. In addition, the positive employment impacts from well construction and development—and the related economic impacts derived from that employment—would generate more in-migration to the region. In time, the additional new residents to the areas would expand the regional labor force and reduce the pressure on labor costs.

Income

The increase in direct and indirect employment would have a positive impact on income levels in regions where natural gas development occurs. Table 6.36 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 to Year 30), total annual construction earnings in a region could range from a low of $15.0 million in Region C under the low development scenario to nearly $597.0 million under the average development scenario in Region A. In Year 30, the year that the maximum number of production workers are assumed to be employed, regional employee earnings from production employment could range from a low of $6.1 million in Region C under the low development scenario to a high of $242.4 million in Region A under the average development scenario.

Table 6.36 - Maximum Direct and Indirect Earnings Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Earnings[1]	$149.2	$597.0
Production Earnings[2]	$60.6	
Indirect Earnings Impacts[3]	**$44.0**	**$176.0**
Total Earnings Impacts	**$253.8**	**$1,015.4**
Total Earnings as a Percentage of Region A's 2009 Total Wages	4.7%	18.7%
Region B		
Direct Earnings Impacts		
Construction Earnings[1]	$68.6	$274.6
Production Earnings[2]	$27.9	$111.5
Indirect Earnings Impacts[3]	**$12.9**	**$51.6**

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Total Earnings Impacts	**$109.4**	**$437.7**
Total Earnings as a Percentage of Region B's 2009 Total Wages	4.8%	19.3%
Region C		
Direct Earnings Impacts		
Construction Earnings[1]	$15.0	$59.7
Production Earnings[2]	$6.1	$24.2
Indirect Earnings Impacts[3]	$4.5	$17.8
Total Earnings Impacts	$25.6	$101.7
Total Earnings as a Percent of Region C's 2009 Total Wages	0.9%	3.7%

Source: U.S. Bureau of Economic Analysis 2011b, 2011c, 2011d; NYSDOL 2009.

1 These figures represent the maximum annual construction earnings under each scenario and correspond to construction earnings in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

2 These figures represent the maximum annual production earnings under each development scenario. These figures correspond to production employee earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production and indirect employee earnings for all other years.

3 Separate Type I direct earnings multipliers for the oil and gas extraction industry from the US Bureau of Economic Analysis, Regional Input- Output Modeling System (RIMS II) for each region were used to estimate the indirect employment impacts.

Total employee earnings in all of the regions are expected to increase significantly. Region A would experience annual increases in employee earnings of approximately $254 million to $1.0 billion, or 4.7% to 18.7% of the 2009 total wages and salaries for the region. Similarly, Region B would experience annual increases in employee earnings of approximately $109 million to $438 million, or 4.8% to 19.3% of 2009 total wages and salaries for the region. Region C would also experience a significant impact in its annual employee earnings. Employee earnings in this region would increase from approximately $26 million to $102 million, or 0.9% to 3.7% of the 2009 total wages and salaries for the region (see Table 6.36).

Owners of the subsurface mineral rights where wells are drilled would also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or greater of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, could result in significant increases in income. In addition, mineral rights owners often receive large signing bonuses/bonus bids as part of the lease agreements.

Impacts on Other Industries

The proposed high-volume hydraulic-fracturing operations would affect not only the size of the regional economies as described above, but would also have an impact on other industries in the economy.

As previously described, suppliers of the natural gas extraction industry would experience significant increases in demand for their goods and services. Over time, these industries would expand and their importance in the regional economies would likewise increase. As shown in Section 2.4.11, Economy, Employment, and Income, the industries expected to experience the greatest indirect, or secondary, growth due to expansion of the natural gas extraction industry would be real estate; the professional, scientific, and technical industries; the management of companies and enterprises; construction; and manufacturing industries. For every $1 million change in the final demand generated in the natural gas extraction industry, a corresponding significant level of output would be generated in these industries. Typically, a change in final demand in an industry is defined as the change in output of that industry multiplied by the value or price of its output. In this case, a $1 million increase in the value of output from the natural gas extraction industry would generate $47,100 in the real estate and rental and leasing industry; $30,500 in the professional, scientific, and technical services industry; and $27,600 in the management of companies and enterprises industry. See Section 2.4.15 for a discussion of indirect impacts on other industries in New York State.

Each of these secondary industries would experience increases in their output, employment, income and value added. As a result, industries that supply these secondary industries would also experience a positive economic impact, and they would expand as demand for their goods and services increases. Secondary, and eventually even tertiary, suppliers would start to tailor their products to meet the needs of the natural gas extraction industry.

Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.

Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry. Property values also may experience some increase as a result of the natural gas development and the resulting increase in economic activity. The potential increase in land prices, which is one of the main factors of production for agriculture, could impact the industry's input costs in areas experiencing the most intense development.

6.8.2 Population

This section presents a summary of the population and demographic findings of the Economic Assessment Report (2011) written by Ecology and Environment Engineering, P.C.

As described previously, three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels. The designation of these areas as representative regions does not mean that the impacts would necessarily be limited to those areas. Until the production potential of low-permeability reservoirs is proven, it is not possible to predict where every potential high-volume hydraulically fractured well may be sited; wells could be developed anywhere there is low-permeability shale. The local and regional impacts presented here are intended only to provide order-of-magnitude estimates for the range of potential impacts. See the Economic Assessment Report for a more detailed discussion on the selection of these representative regions.

To assess the maximum potential population impacts, the discussion below is based on a hypothetical situation in which all workers hired for the construction and production phases of the natural gas wells either migrate into the regions from other areas, or workers migrate into the regions from other areas to fill positions which local construction and production workers vacate to work on the natural gas wells.. Although this hypothetical situation is used to examine the maximum potential population impacts, it is more likely that the actual outcome would be less than described. Not all workers employed during the construction and production phases would necessarily live in New York State or one of the representative regions. Particularly in the case of well development and production in the Southern Tier, existing natural gas workers currently residing in Pennsylvania, for example, may simply choose to maintain their residency in Pennsylvania and commute to work in New York.

In addition, actual population impacts may also be less than what is described in the following section because some currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

The hiring of currently employed local workers (i.e., those workers that leave existing jobs to work in the natural gas industry) is not expected to reduce total in-migration to the regions as it is assumed that the jobs these local workers are leaving would need to be filled. Given the finite number of workers in the regional labor force, any growth in the total number of jobs available in regional economies not filled by currently unemployed or underemployed persons would lead to in-migration to the areas.

The following additional assumptions were used to project population impacts:

- The majority of construction jobs and related population migration to the regions would be temporary and transient in nature in the beginning of the well development phase. As well construction continues, these jobs would gradually be filled by permanent residents.

- Transient construction workers are assumed to temporarily relocate to the region for a short-duration and are assumed to not be accompanied by their households. Permanent construction workers are assumed to relocate to the region for the duration of the well development phase and would be accompanied by their entire households.

- Production jobs and related population migration to the regions would be permanent and entire households would relocate to the regions.

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.

- Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

- The 2010 average household sizes in New York State (2.64 persons per household), Region A (2.47 persons per household), Region B (2.52 persons per household), and Region C (2.49 persons per household) were used in estimating the population impacts associated with permanent construction and production jobs (USCB 2010).

- There would be no involuntary displacement of persons due to construction of the natural gas wells, as no buildings would be demolished to make way for wells and wells need to be drilled at least 500 feet away from private wells and 100 feet from inhabitated dwellings.

6.8.2.1 New York State

Both transient and permanent population impacts are expected to occur as a result of natural gas well construction. Given the highly specialized nature of natural gas construction, workers with the skills required to complete a high-volume hydraulic fracturing operation would not be currently available in New York State or in the representative regions. If high-volume hydraulic fracturing operations were to begin in New York State, most of the skilled workers would initially need to be recruited from outside the state and would be both temporary and transient in nature.

As the industry matures and as more natural gas development occurs in the state and representative regions, more local persons would acquire the requisite skills needed for these jobs, and recruitment from within the existing labor force would therefore increase. Also, as the industry expands and development becomes more assured, the incentive for previously transient workers to become permanent residents within the state or representative regions would increase. Therefore, it would be expected that eventually there would be a decline in the number of transient construction workers and an increase in the number of permanent construction workers.

In an effort to estimate the mix of transient and permanent construction workers, data collected by the Marcellus Shale Education and Training Center on the occupational composition of the natural gas workforce and data from the U.S. Bureau of Economic Analysis' 2008 National Employment Matrix were used to help forecast the amount of local labor that would be employed in natural gas well development (Marcellus Shale Education and Training Center 2009; U.S. Bureau of Economic Analysis 2011e). Initially no more than 23% of the construction workforce is expected to be hired locally. Due to New York State's small existing natural gas industry, the remaining 77% of the workforce would have specialized skills that would most likely be unavailable among New York's labor force in Year 1. Given the newness of the industry, it is assumed that, in Year 1, 77% of the total workforce would be transient workers from outside the state.

As the natural gas industry matures the number of qualified workers in the state and representative regions would increase. This pool of qualified workers would expand as existing local residents gain the requisite skills and/or formerly transient workers permanently relocate to the state or representative regions. The total number of transient construction workers would gradually increase as the rate of well development increased until Year 10 when the maximum number of transient construction workers under both development scenarios is reached. From Years 11 to 30 the transient population would gradually decrease as a proportion of the total construction workforce. By Year 30 it is assumed that the natural gas industry would be sufficiently mature that 90% of all workers could be hired locally. Table 6.37 shows the transient, permanent, and total construction employment for select years. See the Economic Assessment Report for a more detailed discussion of how these figures were derived.

Table 6.37 - Transient, Permanent and Total Construction Employment Under Each Development Scenario for Select Years: New York State (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	342	97	439	1,370	389	1,759
5	1,517	693	2,210	6,051	2,766	8,817
10	2,409	1,999	4,408	9,639	7,995	17,634
15	1,759	2,649	4,408	7,038	10,596	17,634
20	1,181	3,227	4,408	4,725	12,909	17,634
25	740	3,668	4,408	2,959	14,675	17,634
30	441	3,967	4,408	1,763	15,871	17,634

Since the natural gas wells are expected to stay in operation for 30 years, production workers are assumed to be permanent workers who reside close to where the wells are located. Thus, these workers would live in or relocate their families to the area. Wells drilled in Year 1 are expected to remain in operation until Year 30; wells drilled in Year 30 would remain in operation until Year 60.

It is assumed that the households of permanent construction workers and production workers would, on average, be the same size as existing New York households (i.e., 2.64 persons, including the single worker). Therefore, in projecting population impacts, it is anticipated that transient construction workers would be temporary residents unaccompanied by family members, whereas permanent construction workers and all production workers would be permanent residents accompanied by an average of 1.64 family members.

Based on the above assumptions, Table 6.38 displays, for New York State as a whole and for each development scenario, the estimated transient and permanent populations resulting from construction and production activities for Years 1, 10, 20, 30, 40, 50, and 59.

Table 6.38 - Estimated Population Associated with Construction and Production Employment for Select Years: New York State (New August 2011)

		Transient Population	Permanent Population		
Production Year	**Development Scenario**	**Construction**	**Construction**	**Production**	**Total**
1	Low	342	256	18	275
	Average	1,370	1,026	74	1,100
10	Low	2,409	5,277	1,019	6,296
	Average	9,639	21,107	4,079	25,186
20	Low	1,181	8,519	2,872	11,392
	Average	4,725	34,080	11,492	45,572
30	Low	441	10,473	4,726	15,198
	Average	1,763	41,898	18,905	60,803
40	Low	0	0	3,707	3,707
	Average	0	0	14,829	14,829
50	Low	0	0	1,853	1,853
	Average	0	0	7,413	7,413
59[1]	Low	0	0	185	185
	Average	0	0	742	742

Note:

[1] Year 59 is used instead of Year 60 since it is assumed that all operational wells would cease production at the beginning of Year 60.

Under the low development scenario, between Years 10 and 30, it is projected that a maximum of 4,408 construction workers would temporarily or permanently migrate into the areas. The maximum transient construction workforce would occur in Year 10, with an estimated 2,409 transient workers. (During this same year, there would be 1,999 permanent workers relocating to the area.) Under the average development scenario, between Years 10 and 30, it is projected that a maximum of 17,634 construction workers would temporarily or permanently migrate to the well construction areas. The maximum transient workforce would occur in Year 10, with an estimated 9,639 transient workers. (During this same time period, there would be 7,995 permanent workers relocating to the area.) The population impact of the maximum number of transient workers, 9,639 transient workers for the average development scenario, represents less than 0.1% of the total present population of New York State, indicating that transient workers would have only a minor short-term population impact at the state level.

Under the low development scenario, the number of persons permanently migrating to the impacted areas to construct and operate the wells is projected to reach its maximum of 15,198 persons during Year 30 (see Table 6.39). Under the average development scenario during Year 30, it is projected that 60,803 persons would permanently migrate to the impacted areas. Since it is assumed that permanent construction and production workers would relocate with their households, these population estimates include the permanent construction and production workers and members of their households. The maximum impact on the permanent population under the average development scenario is 60,803 persons in Year 30. This figure represents approximately 0.3% of the total present population of New York State, indicating that some long-term population impact could occur at the state level as a result of the operation of the new natural gas wells.

Table 6.39 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production: New York State (New August 2011)

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
New York State	19,378,102	Low	2,409	>0.1%	15,198	>0.1%
		Average	9,639	>0.1%	60,803	0.3%

Notes:

1 Existing population from U.S. Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum operational impacts occur during production year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

According to the population projections developed by Jan K. Vink of the Cornell University Program on Applied Demographics, the population of New York State is expected to increase by 1,037,344 persons over the next 20 years (i.e., by an average of approximately 52,000 persons per year) (Cornell University 2009). Consequently, the maximum cumulative population impact of 60,803 persons, which occurs during production year 30, is slightly more than one year's projected incremental population growth for New York State.

Although the maximum population impacts would be relatively minor at the level of the whole state, natural gas wells would not be spread evenly across the state; they would be concentrated in particular areas where the influx of construction workers and production workers and their families may have more significant population impacts. Similarly, because new wells would not be developed evenly over time due to swings in well development activity, the population impacts would be greater in some years than in others.

In addition to direct employment (employment impacts from construction and production), there are projected indirect employment impacts from the development of hydraulic fracturing operations in the area underlain by the Marcellus and Utica Shales (see Section 6.10.1). Given the relatively high unemployment rates currently being experienced in these regions, it is likely that some of these new, indirectly created jobs (e.g., gas station clerks, hotel lobby personnel, etc.) would be filled by local, previously unemployed or underemployed persons. These indirect employment impacts would reduce local unemployment and help stimulate the local economies. The impacts associated with the influx of construction workers, both transient and permanent, would last as long as wells are being developed in an area, whereas the impacts associated with the production phase could last up to 60 years.

6.8.2.2 Representative Regions

Table 6.40,Table 6.41 and Table 6.42 show the estimated transient, permanent, and total construction employment for Regions A, B, and C under the low and average development scenario.

Table 6.40 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region A (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	171	48	219	686	194	880
5	758	347	1,105	3,026	1,383	4,409
10	1,205	999	2,204	4,820	3,998	8,818
15	880	1,324	2,204	3,520	5,298	8,818
20	591	1,613	2,204	2,363	6,455	8,818
25	370	1,834	2,204	1,480	7,338	8,818
30	220	1,984	2,204	882	7,936	8,818

Table 6.41 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region B (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	79	22	101	315	89	404
5	349	159	508	1,392	636	2,028
10	554	460	1,014	2,217	1,839	4,056
15	405	609	1,014	1,619	2,437	4,056
20	272	742	1,014	1,087	2,969	4,056
25	170	844	1,014	681	3,375	4,056
30	101	913	1,014	406	3,650	4,056

Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	17	5	22	69	19	88
5	75	35	110	303	138	441
10	121	100	221	482	400	882
15	88	133	221	352	530	882
20	59	162	221	236	646	882
25	37	184	221	148	734	882
30	22	199	221	88	794	882

Table 6.43 shows the maximum population impacts associated with transient and permanent construction workers and permanent production workers for the three representative regions. As noted above, the three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels, and the projected local and regional impacts presented here are intended to provide order-of-magnitude estimates for the range of potential impacts. In constructing Table 6.43 it was assumed, as discussed above, that a portion of the construction workers would be temporary, transient residents in an area and would not be accompanied by members of their households. The remainder of the construction workers would be permanent residents. The proportion of permanent workers to transient workers would gradually increase over time. All production workers are assumed to be permanent residents and would relocate their families to the area. Since the households of permanent construction and production workers are assumed to be the same size as average households in their respective regions, permanent workers are assumed to be accompanied by an average of 1.47 family members in Region A, 1.52 family members in Region B, and 1.49 family workers in Region C.

Table 6.43 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts[3]	% Increase from Total Existing 2010 Population
A	340,555	Low	1,205	0.4%	7,111	2.1%
		Average	4,820	1.4%	28,447	8.4%
B	187,786	Low	554	0.3%	3,339	1.8%
		Average	2,217	1.2%	13,348	7.1%
C	215,222	Low	121	<0.1%	720	0.3%
		Average	482	0.2%	2,868	1.3%

Notes:

1 Existing population from US Census Bureau's *2010 Census of Population* (USCB 2010).

2 Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

3 Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

The upper bound of the potential impacts is found in Region A under the average development scenario, when in Year 10 there are projected to be 4,820 unaccompanied transient workers, representing 1.4% of the region's total population. The upper bound of the potential impacts from permanent population changes can be found in Region A under the average development scenario in Year 30, when 28,447 permanent construction and production workers and their household members would be residing in the region. This figure represents 8.4% of the existing population in Region A. According to the population projections presented in Section 2.4.11, in the absence of gas well development, Region A is expected to experience a future population decrease and to have a 2030 population of 279,675 persons, a decrease of 60,880 persons, equal to 17.9% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 28,447persons in Year 30 under the average development scenario, would offset approximately 47% of the projected population decline in Region A and would, therefore, have a beneficial impact.

Under the average development scenario, Region B is projected to have a maximum of 2,217 unaccompanied, transient construction workers and 13,348 permanent construction and production workers and their family members residing in the region. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. The maximum transient population would account for 1.2% of the existing population in Region B, and the maximum permanent population would account for 7.1% of the existing population, respectively. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region B is expected to experience a future population decrease and to have a 2030 population of 183,031 persons, a decrease of 4,755 persons, equal to 2.5% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 13,348 persons in Year 30 under the average development scenario, would more than offset the projected population decline in Region B but would not add significantly to the existing population.

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 5

Natural Resources Defense Council, Earthjustice, and Sierra Club, *Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels* (June 29, 2011)

January 27, 2012

June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.
[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.
[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.
[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:

Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:

Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:

To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term "cement bond log" refers to out-dated technology and the terms "cement evaluation logs," "cement integrity logs" or "cement mapping logs" are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:
Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:
Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:
These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:
Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of “injection.” Operators should also run caliper and resistivity logs. The term “fracture finder logs” refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

What should the permit duration be and how should Class II plugging and abandonment provisions be addressed for Class II wells using diesel fuels for HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

    e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

   Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well’s type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

    c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

How could Class II financial responsibility requirements be met for wells using diesel fuels for hydraulic fracturing?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

What public notification requirements or special environmental justice considerations should be considered for authorization of wells using diesel fuels for hydraulic fracturing?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 6

Sierra Club, et al., *Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO,* Docket No. EPA-HQ-OAR-2010-0505 (Nov. 30, 2011)

January 27, 2012

BEFORE THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO	))))	**Docket No. EPA-HQ-OAR-2010-0505** *Via regulations.gov and e-mail* *November 30, 2011*

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I. INTRODUCTION

Thank you for accepting these comments on behalf of the Sierra Club, the Center for Biological Diversity, Clean Air Council, the Clean Air Task Force, Earthjustice, Earthworks, the Environmental Defense Fund, the Natural Resources Defense Council, the Network for Oil and Gas Accountability and Protection, the San Juan Citizens Alliance, WildEarth Guardians, the West Virginia Surface Owners' Rights Organization, and the Wyoming Outdoor Council. Collectively, we represent millions of members, including many thousands who live and recreate in areas affected by oil and gas operations. On behalf of our members, we thank EPA for updating and expanding the performance standards for this industry, which is rapidly expanding across the United States.

EPA's proposed New Source Performance Standards (NSPS) for the oil and natural gas industry are a long awaited and much needed update. EPA originally included crude oil and natural gas production on the list of air pollution sources that require a NSPS in

1979.[1] Since then, EPA has only promulgated standards for natural gas processing plants, an extremely limited subset of facilities within the industry.[2] EPA failed to regulate oil and gas facilities that emit substantial amounts of air pollution, such as wells, pipelines, and any compressors, valves or storage tanks not located at processing plants. Since EPA last revised the NSPS for this sector, the growth of hydraulic fracturing and horizontal drilling has led to the unprecedented expansion of the oil and gas industry into new areas. This expansion, along with existing development in established oil and gas producing regions, has substantial negative impacts to public health and the environment.

EPA's proposed NSPS contains some good first steps towards addressing the increasing emissions and air pollution from this industry. In particular, we applaud EPA's decision to expand the NSPS to address hydraulic fracturing at well-sites and to cover additional oil and gas facilities, such as compressors, pneumatic controllers, and storage vessels. However, there is still more to be done to make these standards fully compliant with the rigorous requirements of Section 111 of the Clean Air Act.[3]

In Part I of our comments, we review EPA's basic legal obligations under Section 111 and provide an overview of the expanding oil and gas industry and the need for strong air quality regulations. Building on that foundation, in Part II, we provide a technical review of EPA's proposed standards and compare them to those statutory obligations. We identify important gaps in the standards, such as the failure to regulate air emissions from conventional gas wells (those which do not use hydraulic fracturing) or oil wells of any type.

Parts III, IV, and V of our comments address critical gaps in the proposal. EPA has failed to regulate certain sources of pollution, including offshore facilities, oil- and gas-field heater-treaters, and drilling rigs. EPA also has failed to regulate pollutants emitted by the industry, including methane, particulate matter, hydrogen sulfide, and nitrogen oxides. And EPA has failed to regulate many existing sources of pollution, even though they are responsible for the lion's share of the current emissions. We discuss what the law and the scientific evidence require of EPA in each instance.

In Part VI, we address EPA's enforcement and compliance obligations under the statute, which necessitate important changes to EPA's proposal, including retaining oil and gas sector sources in the Title V program, and eliminating EPA's illegal proposed affirmative defense.

In Part VII, we explain how EPA overestimated the costs of air pollution controls and underestimated the benefits. Part VIII demonstrates that industry growth and rigorous

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[1] 44 Fed. Reg. 49,222 (Aug. 21, 1979), attached hereto as Exhibit 1.
[2] 40 C.F.R. Part 60, Subparts KKK & LLL.
[3] 42 U.S.C. § 7411 *et seq.*

clear air regulations can go hand in hand. In fact, the industry has continued to grow despite regulations of the sort that EPA proposes.

In Part IX, we strongly urge EPA to close as many of the gaps in the proposed rule as possible, without delaying finalization by April 3, 2012, as is legally required. In Part X, we emphasize, however, that to the extent that certain obligations simply cannot be met by that date, EPA may not defer any remaining necessary rulemakings indefinitely. Should any necessary rulemaking activity remain beyond this deadline, EPA must complete it by 2013, rather than allowing its already illegally long failure to fully regulate this major industry to persist. EPA may, under no circumstances, defer rulemaking until its next review, which is not required to occur for another eight years. During any delay, unacceptable air pollution will continue to be caused by the industry's improperly controlled emissions.

Several reports from recognized experts support our positions. They are attached to these comments, and incorporated by reference.
Throughout this report, we make many recommendations, which are intended to bring EPA's proposal into compliance with the Clean Air Act. EPA must respond to each recommendation in full. If it opts not to take a recommendation, EPA must explain its rationale in its response to comments.

A. Legal Overview of Section 111 of the Clean Air Act

Section 111 of the Clean Air Act ("CAA" or "Act") requires EPA to set technology-based standards of performance for industrial sources of air pollution.[4] These federal standards of performance apply to all new and modified sources in a listed source category.[5] Because these standards apply to sources in designated or "listed" industrial categories regardless of the ambient air quality in a particular area, they help to prevent new air pollution problems as well as prevent existing problems from worsening. These goals are particularly important with respect to the oil and gas industry, which is responsible for substantial existing air pollution problems and is rapidly expanding into new areas.[6]

[4] *See* 42 U.S.C. § 7411.
[5] 42 U.S.C. 7411(b)(1)(B), (a)(2).
[6] The emission limits established by the standard must be met by sources within listed categories that commence construction or undergo modification after the date of the *proposal* of such standard. *See* 42 U.S.C. §§ 7411(a)(2) (a "new source" is "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance"). Any new source within a listed category that begins operation or any existing source that receives, or should receive, a permit to undergo a modification under Section 111 after the published date of the proposal for the standard must therefore comply with the standard EPA promulgates in the final rule.

New source performance standards must be promulgated on a rigorous timeline, which EPA failed to meet for this industry. Section 111(b)(1)(A) provides:

> The Administrator *shall*, within 90 days after December 31, 1970, publish (and from time to time thereafter *shall* revise) a list of categories of stationary sources. [Sh]e *shall* include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.[7]

Section 111 further provides that within one year following the listing of each such source category, EPA "*shall* publish proposed regulations, establishing Federal standards of performance."[8] Once EPA establishes the standards of performance, it "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[9]

EPA first proposed new source performance standards for the oil and natural gas industry in 1985.[10] EPA therefore was required to review and revise its 1985 standards no later than 1993. Air pollution emissions from this sector have grown in the interim, and although available control techniques have markedly improved, they have not been consistently applied, because of the delay in revising the requirements to do so. For that reason, it is essential that EPA comply with section 111's high standards in finalizing this rule, as so many sources have gone uncontrolled for so long. Specifically, EPA's updated "standard of performance" must meet the statutory definition:

> 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 requirements) the Administrator determines has been adequately demonstrated.[11]

"This section directs EPA to set specific and rigorous limits on the amounts of pollutants that may be emitted from any 'new source' of air pollutants" and "reflect a commitment to requiring the best technology."[12] This "best demonstrated technology" ("BDT") or

[7] 42 U.S.C. § 7411(b)(1)(A) (emphases added).
[8] *Id.* § 7411(b)(1)(B) (emphasis added).
[9] *Id.* (emphasis added).
[10] *See* 50 Fed. Reg. 26122 (June 24, 1985) (promulgation of VOC NSPS covering leaking components as onshore natural gas processing plants), attached hereto as Exhibit 1; 50 Fed. Reg. 40158 (Oct. 1, 1985) (promulgation of NSPS for SO_2 emissions from natural gas processing plants), attached hereto as Exhibit 2.
[11] 42 U.S.C. § 7411(a)(1).
[12] *ASARCO Inc. v. EPA*, 578 F.2d 319, 322 & 322 n.6 (D.C. Cir. 1978), attached hereto as Exhibit 3.

"best system of emission reduction"("BSER") standard[13] is designed to "enhance air quality and not merely to maintain it" by "forcing all newly constructed or modified [facilities] to employ pollutant control systems" that will reflect the best demonstrated system of reduction."[14]

Section 111 is a technology-forcing program. Congress' intent was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution."[15] As such, the courts are clear that the "standards should be stringent in order to force the development of improved technology."[16] As the D.C. Circuit has explained, "[s]ection 111 looks toward what may fairly be projected for the regulated future, rather the state of the art at present, since it is addressed to standards for new plants."[17] The required technology need not "be in actual routine use somewhere"; rather, the "essential question," is "whether the [required] technology would be available for installation in new plants."[18]

Because EPA is to set standards that new sources in the industry can meet in the future,[19] it need not set a standard that can be met by every plant "currently in operation . . . at all times and under all circumstances."[20] In other words,

> An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.[21]

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[13] EPA refers to the standard as "BSER" in this rulemaking, though BDT is the traditional abbreviation . We do not understand EPA's terminological choice to reflect a change in its interpretation of the statute, but the agency must say so, if it is changing its view. We use the terms interchangeably in these comments, understanding both to require emissions limits meeting the statutory standard at each individual facility covered by the standard.

[14] *ASARCO* at 327; *see also Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976) (discussing these standards), attached hereto as Exhibit 4.

[15] *Sierra Club v. Costle,* 657 F.2d 298, 347 n.174 (D.C. Cir. 1981) (quoting legislative history), attached hereto as Exhibit 5. *See also ASARCO, Inc. v. EPA,* 578 F.2d 319, 322 & n.6 (D.C. Cir. 1978) (The language of section 111 evinces the Congressional "commitment to requiring the best technology" as "[NSPS] are designed to force new sources to employ the best demonstrated systems of emission reduction.")

[16] *ASARCO* at 325.

[17] *Id.* at 391.

[18] *Id. See also Lignite Energy Council v. U.S. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (Achievability "'looks toward what may be fairly projected for the regulated future, rather that the state of the art at present'", attached hereto as Exhibit 6. (quoting *Portland Cement*, 486 F.2d at 391).

[19] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391-92 (D.C. Cir. 1973), attached hereto as Exhibit 7.

[20] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433-34 (D.C. Cir. 1973), attached hereto as Exhibit 8.

[21] *Id*. at 433. *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 (D.C. Cir. 1980) (achievability is determined "for the industry as a whole."), attached hereto as Exhibit 9.

Whether a "system of emission reduction" is achievable and has been adequately demonstrated is a question of reasonableness: [22]

> An adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.[23]

While EPA is to consider the costs "of achieving [the] reduction" (along with nonair quality health and environmental impacts and energy requirements) when setting a standard of performance, EPA must not lose sight of the technology forcing nature of section 111.[24] The cost issue before the agency is whether the cost of new source control is "greater than the industry could bear and survive." [25]

Where it is "not feasible to prescribe or enforce a standard of performance," EPA must instead "promulgate a design, equipment, work practice, or operational standard, or combination thereof, which reflects the best technological system of continuous emission reduction" which is adequately demonstrated.[26] This authority is limited by the Act, which defines the narrow circumstances in which it is "not feasible" to set a standard of performance, including when EPA determines that "a pollutant or pollutants cannot be emitted through a conveyance" capable of capturing such pollutants or that "the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."[27]

Finally, EPA's standard-setting obligations extend to existing sources of some air pollutants. For air pollutants that are not criteria pollutants listed under section 108 or hazardous air pollutants listed and regulated under 112, EPA must prescribe regulations setting out existing source performance standard requirements, to be adopted and implemented by the states.[28]

B. Overview of the Oil and Gas Industry.

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[22] In determining what technologies are "adequately demonstrated" to form the basis for an "achievable" performance standard for a particular source category, courts have held that EPA's analysis can – indeed should, as appropriate – look beyond facilities within the United States. EPA may base its standards on the application of systems of control that are in use in other countries, as well as looking at technology transfers across industries as the basis for an "achievable" performance standard, "*Lignite Energy Council*, 198 F.3d at 933-34 & n.3.

[23] *Id.*

[24] *Lignite Energy Council*, 198 F.3d at 933 (citing *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992)).

[25] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) ("*Portland Cement II*"), attached hereto as Exhibit 10; *see also Lignite Energy Council*, 198 F.3d at 933 (EPA may exclude emission controls that would impose "exorbitant" economic or environmental costs).

[26] 42 U.S.C. § 7411(h)(1).

[27] *Id.* § 7411(h)(2).

[28] *See* 42 U.S.C. § 7411(d).

1. The oil and gas industry is rapidly expanding

Oil and gas development in the United States is on the rise. In 2009, there were over a million wells producing oil and natural gas nationwide.[29] This includes conventional onshore and offshore oil and gas production as well as unconventional coal bed methane, tight gas, and shale oil and gas production.[30] Although the mix of production from these sources is likely to change, the U.S. Energy Information Administration ("EIA") predicts increases in both domestic crude oil and natural gas production over the near term.[31] The EIA predicts that crude oil development will rise until around 2019 and then fall off slightly, and that there will be substantial increases in overall natural gas production between 2009 and 2035.[32] With respect to natural gas development, the EIA predicts drilling will increase by 190% in shale reservoirs, by 138% in tight sands, and by 61% in coalbed methane reserves.[33]

The dramatic rise in shale development is the result of advances in hydraulic fracturing and horizontal drilling that have allowed the industry to unlock oil and gas trapped in shale formations that was previously inaccessible. Successful shale gas production started in the Barnett Shale of north central Texas in the early years of the past decade.[34] Since then, the growth of shale gas development has been extremely rapid. Natural gas now provides approximately 25% of the domestic energy supply.[35] Although shale gas made up less than 2% of gas production in 2001, it now constitutes around 30%.[36] That trend is expected to continue: the EIA predicts shale gas will be 47% of production by 2035.[37]

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[29] EPA, *Proposed Amendments to Air Regulations for the Oil and Natural Gas Industry, Fact Sheet*, at 2, *available at* http://epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf (hereinafter "EPA Fact Sheet"), attached hereto as Exhibit 11.

[30] EIA, *Annual Energy Outlook 2011*, at 79, 82, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf, attached hereto as Exhibit 12.

[31] EPA, *Regulatory Impact Analysis* ("RIA") at 2-26 to 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[32] RIA at 2-28; *see also* EIA, Annual Energy Outlook 2011, at 79, 82.

[33] RIA at 2-27.

[34] EIA, *Annual Energy Outlook 2011, Prospects for Shale Gas*, *available at* http://www.eia.gov/forecasts/aeo/IF_all.cfm#prospectshale, attached hereto as Exhibit 13; *see also* Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), *available at* http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf. (hereinafter "Barnett Shale Report"), attached hereto as Exhibit 14.

[35] U.S. Dep't of Energy, Secretary of Energy Advisory Board, *Shale Gas Production Subcommittee 90-Day Report*, at 6 (Aug. 18, 2011). (hereinafter "SEAB Interim 90-Day Report"), *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf, attached hereto as Exhibit 15.

[36] *Id.*; *see also* U.S. Energy Information Administration (EIA), *Outlook for Natural Gas*, at slide 14 (2010), *available at* http://205.254.135.24/neic/speeches/newell101110.ppt (showing 14-fold increase in shale gas development between 200 and 2010, with sharp increase after 2008), attached hereto as Exhibit 16.

[37] EIA, *Outlook for Natural Gas*, at slide 14; *see also* SEAB 90-Day Report at 6-7.

Shale gas production is expected to increase in almost every region of the country, including the Northeast, Gulf Coast, Midcontinent, Southwest, and Rocky Mountain regions.[38] The increase will be dramatic in the Marcellus shale in Northeast, which has only recently been subject to significant shale gas development. Already, Pennsylvania is experiencing large increases in drilling.[39] Even states with a long-history of oil and gas development, such as Colorado and Wyoming, have experienced and will continue to experience shale gas development in new areas.[40]

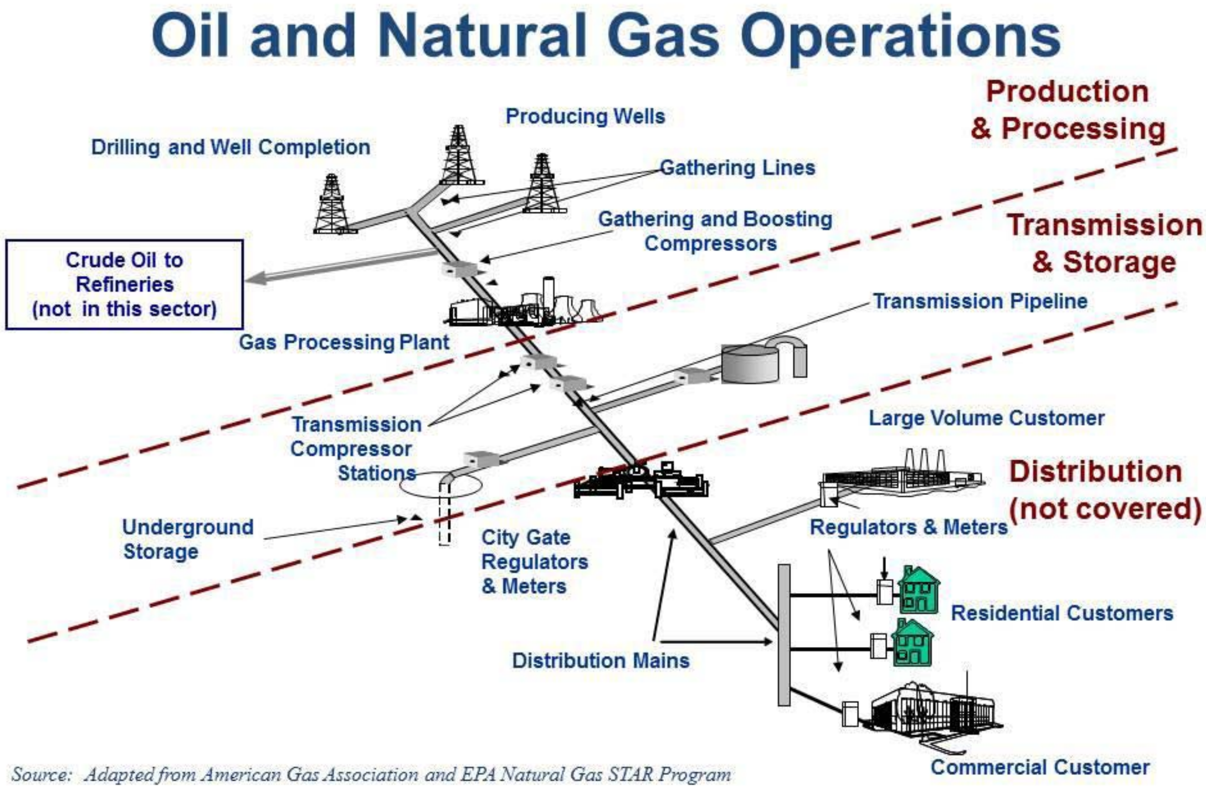
Development of shale oil is also on the rise.[41] Since the beginning of 2008, the number of active oil rigs has increased 242%, reaching a 24-year high in October of this year.[42] Much of this increase is attributable to development of shale oil plays, such as the Bakken in North Dakota, that are now accessible because of hydraulic fracturing and horizontal drilling techniques.[43] Although shale oil production was negligible a few years ago, industry estimates that it could reach 2 million barrels per day in the next five years.[44]

2. The oil and gas industry is responsible for substantial amounts of emission and air pollution that is harmful to public health and the environment

Oil and gas development includes numerous stages and facilities, all of which contribute to substantial amounts of air emissions and resultant dangerous air pollution. EPA has defined the "oil and gas sector" for the purposes of this rule to include the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas.[45] As depicted below, the sector includes four stages: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission, and (4) natural gas distribution.[46]

[38] EIA, *Annual Energy Outlook 2011*, at 80.
[39] *SEAB Interim 90-Day Repor*t at 8.
[40] *Id*.
[41] EIA, *Annual Energy Outlook 2011*, at 82.
[42] *See* Update 2—U.S. Oil Rig Count Hits Record—Baker Hughes, *available at* http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014.http://uk.reuters.com/article/2011/10/14/energy-oil-rigs-idUKN1E79D11420111014, attached hereto as Exhibit 17.
[43] *Id.*
[44] *Id.*
[45] 76 Fed. Reg. 52744. at 52,738, 52,744 (Aug. 23, 2011).
[46] EPA, *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 Rules* ("TSD") at 2-4 (July 2011).

Figure 1: The Oil and Natural Gas Sector



Within these development stages, the major sources of air pollution include wells, compressors, pipelines, pneumatic devices, dehydrators, storage tanks, pits and ponds, natural gas processing plants, and trucks and construction equipment. Major air pollutants of concern from these operations include methane (CH_4), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and particulate matter (PM_{10} and $PM_{2.5}$). Oil and natural gas operations also emit listed hazardous air pollutants (HAPs), which are regulated separately by National Emissions Standards for Hazardous Air Pollutants (NESHAPs); our comments on the proposed NESHAPs for the oil and gas industries are presented in a separate document.

Methane: Methane is the dominant pollutant from the oil and gas sector. Emissions occur as result of intentional venting or unintentional leaks during drilling, production, processing, transmission and storage, and distribution. For example, methane is emitted when wells are completed and vented, as part of operation of pneumatic devices and compressors, and as a result of leaks (fugitive emissions) in pipelines, valves, and other equipment. EPA has identified natural gas systems as the "single largest contributor to United States anthropogenic methane emissions."[47] The industry is responsible for over 40% of total U.S. methane emissions, which amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[48]

Methane is a potent greenhouse gas that contributes substantially to global climate change. Methane has at least 25 times the global warming potential of carbon dioxide over a 100 year time frame and at least 72 times the global warming potential of carbon dioxide over a 20-year time frame.[49]

Because of methane's effects on climate, EPA has found that methane, along with five other well-mixed greenhouse gases, endanger public health and welfare within the meaning of the Clean Air Act.[50] The impacts of climate change caused by methane and other greenhouse gases include "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."[51] A warming climate will also lead to loss of coastal land in densely populated areas, shrinking snowpack in Western states, increased wildfires, and reduced crop yields.[52] More frequent heat waves as a result of global warming have already affected public health, leading to premature deaths. And threats to public health are only expected to increase as global warming intensifies. For example, a warming climate will lead to increased incidence of respiratory and infectious disease, greater air and water pollution, increased malnutrition, and greater casualties from fire, storms, and floods.[53] Vulnerable populations—such as children, the elderly, and those with existing health problems—are the most at risk from these threats.

Methane also reacts in the atmosphere to form ozone.[54] As we discuss below, ozone is a major public health threat, linked to a wide range of maladies. Ozone can also damage vegetation, agricultural productivity, and cultural resources. Ozone is also a

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[47] 76 Fed. Reg. at 52,792.
[48] *Id.* at 52,791–92.
[49] *IPCC 2007—The Physical Science Basi*s, Section 2.10.2, attached hereto as Exhibit 18. We note that these global warming potential figures may be revised upward in the next IPCC report. As discussed in the attached report of Dr. Laurie Johnson (See Exhibit 249), discussed below, another more recent study by Shindell *et al.* estimates methane's 100-year GWP at 33; this same source estimates methane's 20-year GWP at 105.
[50] EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding"), attached hereto as Exhibit 19.
[51] 76 Fed. Reg. at 52,791-22 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011), http://www.epa.gov/climateexchange/emissions/downloads11/US-GHGInventory-2011-Executive Summary.pdf), attached hereto as Exhibit 20.
[52] *Id.* at 66,532–33.
[53] EPA, *Climate Change, Health and Environmental Effects*, *available at* http://epa.gov/climatechange/effects/health.html, attached hereto as Exhibit 21.
[54] 76 Fed. Reg. at 52,791; RIA at 4-27.

significant greenhouse gas in its own right, meaning that methane is doubly damaging to climate – first in its own right, and then as an ozone precursor.

***VOCs and NO_x*:** VOCs and NO_x contribute to the formation of ground-level ozone (also referred to as smog). Smog pollution harms the respiratory system and has been linked to premature death, heart failure, chronic respiratory damage, and premature aging of the lungs.[55] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[56]

Significant ozone pollution also damages plants and ecosystems.[57] Ozone also contributes substantially to global climate change over the short term. According to a recent study by the United Nations Environment Program (UNEP), behind carbon dioxide and methane, ozone is now the third most significant contributor to human-caused climate change.[58]

The oil and gas industry is a major source of the ozone precursors VOCs and NO_x.[59] VOCs are emitted from well drilling and completions, compressors, pneumatic devices, storage tanks, processing plants, and fugitives from production and transmission.[60] The primary sources of NO_x are compressor engines, turbines, and other engines used in drilling and hydraulic fracturing.[61] NO_x is also produced when gas is flared or used for heating.[62]

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[55] RIA at 4-25; Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop, attached hereto as Exhibit 22.

[56] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html attached hereto as Exhibit 23. EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html, attached hereto as Exhibit 24.

[57] RIA at 4-26.

[58] *Id. See also* United Nations Environment Programme and World Meteorological Organization, (2011): *Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers* (hereinafter "UNEP Report," available at http:// www.unep.org/dewa/Portals/67/pdf/Black_Carbon.pdf), at 7, attached hereto as Exhibit 25.

[59] *See, e.g.,* EPA Fact Sheet at 3; Barnett Shale Report at 24.

[60] *See, e.g.,* TSD at 4-7, 5-6, 6-5, 7-9, 8-1; *see also* Barnett Shale Report at 24.

[61] *See, e.g.,* TSD at 3-6; *See also* Barnett Shale Report at 24. *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project* at 11 (Table 2.1).

[62] TSD at 3-6; Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011), available at http://www.cdphe.state.co.us/ap/RegionalHaze/AppendixD/4-FactorHeaterTreaters07JAN2011FINAL.pdf, attached hereto as Exhibit 26.

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of September 2011, there were more than 15,306 gas wells and another 3,212 wells permitted.[63] Of the nine counties surrounding the Dallas Forth Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[64] A 2009 study found that summertime emissions of smog-forming pollutants from these counties were roughly comparable to emissions from motor vehicles in those areas.[65]

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[66] On March 12, 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[67] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[68] Last winter alone, the residents of Sublette County suffered thirteen days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone pollution levels exceeded the worst days of smog pollution in Los Angeles.[69] Residents have faced repeated warnings regarding elevated ozone levels and the resulting risks of going outside.[70]

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[63] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf (Accessed Nov. 21, 2011), attached hereto as Exhibit 27.

[64] Barnett Shale Report at 1, 3.

[65] *Id.* at 1, 25-26.

[66] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415, attached hereto as Exhibit 28.

[67] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf, attached hereto as Exhibit 29; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf, attached hereto as Exhibit 30.

[68] Wyoming Nonattainment Analysis at viii.

[69] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode&msaorcountyValue=56035&poll=44201&county=56035&msa=-1&sy=2011&flag=Y&_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas, attached hereto as Exhibit 31.; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1, attached hereto as Exhibit 32.

[70] *See, e.g., 2011 DEQ Ozone Advisories*, Pinedale Online! (Mar. 17, 2011) (documenting ten ozone advisories in February and March 2011), *available at*

Ozone problems are mounting in other Rocky Mountain states as well. Northeastern Utah recorded unprecedented ozone levels in the Uintah Basin in 2010 and 2011. In the first three months of 2010—which was the first time that winter ozone was monitored in the region—air quality monitors measured more than 68 exceedances of the federal health standard. On three of these days, the levels were almost twice the federal standard.[71] Between January and March 2011, there were 24 days where the National Ambient Air Quality Standard (NAAQS) for ozone were exceeded in the area. Again, ozone pollution levels climbed to nearly twice the federal standard.[72] The Bureau of Land Management (BLM) has identified the multitude of oil and gas wells in the region as the primary cause of the ozone pollution.[73]

Rampant oil and gas development in Colorado and New Mexico is also leading to high levels of VOCs and NO_x. In 2008, the Colorado Department of Public Health and Environment concluded that the smog-forming emissions from oil and gas operations exceed vehicle emissions for the entire state.[74] Moreover, significant additional drilling has occurred since 2008. Colorado is now home to more than 46,000 wells.[75] There is also significant development in the San Juan Basin in southeastern Colorado and northwestern New Mexico, with approximately 35,000 wells in the Basin. As a result of this development and several coal-fired power plants in the vicinity, the Basin suffers

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http://www.pinedaleonline.com/news/2011/03/OzoneCalendar.htm, attached hereto as Exhibit 33; Wyoming Department of Environmental Quality, Ozone Advisory for Monday, Feb. 28, Pinedale Online! (Feb. 27, 2011), *available at* http://www.pinedaleonline.com/news/2011/02/OzoneAdvisoryforMond.htm, attached hereto as Exhibit 34

[71] Scott Streater, *Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future*, N.Y. TIMES, Oct. 1, 2010, *available at* http://www.nytimes.com/gwire/2010/10/01/01greenwire-air-quality-concerns-may-dictate-uintah-basins-30342.html?pagewanted=1 (last visited Sept. 28, 2011), attached hereto as Exhibit 35.

[72] *See* EPA, AirExplorer, Query Concentrations (Ozone, Uintah County, 2011), available at http://www.epa.gov/cgi-bin/htmSQL/mxplorer/query_daily.hsql?msaorcountyName=countycode&msaorcountyValue=49047&poll=44201&county=49047&site=-1&msa=-1&state=-1&sy=2011&flag=Y&query=download&_debug=2&_service=data&_program=dataprog.query_daily3P_dm.sas, attached hereto as Exhibit 36.

[73] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact State*ment ("GASCO DEIS"), at 3-13, *available at* http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html, attached hereto as Exhibit 37.

[74] Colo. Dept. of Public Health & Env't, Air Pollution Control Division, Oil and Gas Emission Sources, *Presentation for the Air Quality Control Commission Retreat*, at 3-4 (May 15, 2008), attached hereto as Exhibit 38.

[75] Colorado Oil & Gas Conservation Commission, *Colorado Weekly & Monthly Oil and Gas Statistics*, at 12 (Nov. 7, 2011), available at http://cogcc.state.co.us/ (library—statistics—weekly/monthly well activity), attached hereto as Exhibit 39.

from serious ozone pollution.[76] This pollution is taking a toll on residents of San Juan County. The New Mexico Department of Public Health has documented increased emergency room visits associated with high ozone levels in the County.[77]

Air quality in national parks and wilderness areas is also suffering as a result of oil and gas development. Researchers have determined that numerous "Class I areas" – a designation reserved for national parks, wilderness areas, and other such lands[78] – are likely to be impacted by increased ozone pollution as a result of oil and gas development in the Rocky Mountain region, including Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.[79] These areas are all near concentrated oil and gas development in the San Juan Basin.[80]

As oil and gas development moves into new areas, particularly as a result of the boom in development of shale resources, ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone NAAQS.[81] Experts also anticipate air quality problems associated with development of the Marcellus shale in the Mid-Atlantic region.[82]

Sulfur dioxide: Sulfur dioxide causes respiratory problems, including increased asthma symptoms. Short-term exposure to sulfur dioxide has been linked to increased emergency room visits and hospital admissions. Sulfur dioxide reacts in the atmosphere to form particulate matter (PM), an air pollutant which causes a great deal of harm to human health.[83] PM is discussed separately below.

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[76] *See Four Corners Air Quality Task Force Report of Mitigation Options*, at vii (Nov. 1, 2007), *available at* http://www.nmenv.state.nm.us/aqb/4C/TaskForceReport.html, attached hereto as Exhibit 40.

[77] Myers *et al.*, *The Association Between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County* (Aug. 2007), *available at* http://www.nmenv.state.nm.us/aqb/4c/Documents/SanJuanAsthmaDocBW.pdf, attached hereto as Exhibit 41.

[78] *See* 42 U.S.C. § 7472(a).

[79] Rodriguez et al., *Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States*, 59 Journal of the Air and Waste Management Association 111 (Sept. 2009), available at http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf, attached hereto as Exhibit 42.

[80] *Id.* at 1112.

[81] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (Nov. 18, 2010), attached hereto as Exhibit 43.

[82] Elizabeth Shogren, *Air Quality Concerns Threaten Natural Gas's Image*, National Public Radio (June 21, 2011), *available at* http://www.npr.org/2011/06/21/137197991/air-quality-concerns-threaten-natural-gas-image, attached hereto as Exhibit 44.

[83] EPA, Sulfur Dioxide, Health, *available at* http://www.epa.gov/air/sulfurdioxide/health.html, attached hereto as Exhibit 45.

The primary source of sulfur dioxide from the oil and gas industry is natural gas processing plants.[84] Sulfur dioxide is released as part of the sweetening process, which removes hydrogen sulfide from the gas.[85] Sulfur dioxide is also created when gas containing hydrogen sulfide (discussed below) is combusted in boilers or heaters.[86]

Hydrogen sulfide: Hydrogen sulfide is an air pollutant with toxic properties that smells like rotten eggs and can lead to neurological impairment or death. Long-term exposure to hydrogen sulfide is linked to respiratory infections, eye, nose, and throat irritation, breathlessness, nausea, dizziness, confusion, and headaches.[87] Although hydrogen sulfide was originally included in the Clean Air Act's list of hazardous air pollutants, it was removed with industry support.[88]

Some natural gas contains hydrogen sulfide. When hydrogen sulfide levels are above a specific threshold, gas is classified as "sour gas."[89] According to EPA, there are 14 major areas in the U.S., found in 20 different states, where natural gas tends to be sour.[90] All told, between 15 and 20% of the natural gas in the U.S. may contain hydrogen sulfide.[91]

Given the large amount of drilling in areas with sour gas, EPA has concluded that the potential for hydrogen sulfide emissions from the oil and gas industry is "significant."[92] Hydrogen sulfide may be emitted during all stages of development, including exploration, extraction, treatment and storage, transportation, and refining.[93] For

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[84] 76 Fed. Reg. at 52,756.
[85] TSD 3-3 to 3-5.
[86] 76 Fed. Reg. at 52,756.
[87] EPA, Office of Air Quality Planning and Standards, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* (EPA-453/R-93-045), at i (Oct. 1993) (hereinafter "EPA Hydrogen Sulfide Report"); *available at* http://nepis.epa.gov/Exe/ZyNET.exe/00002WG3.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1991+Thru+1994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C91thru94%5CTxt%5C00000006%5C00002WG3.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p%7Cf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL, attached hereto as Exhibit 46.
[88] *See* Pub. L. 102-187 (Dec. 4, 1991), attached hereto as Exhibit 47. We do not concede that this approval was appropriate. Hydrogen sulfide meets section 112 of the Clean Air Act's standards for listing as a hazardous air pollutant, and should be so regulated. However, until such time as it is reinstated as an HAP, it must be included in the revised NSPS.
[89] 76 Fed. Reg. at 52,756; RIA at 2-3. Gas is considered "sour" of hydrogen sulfide concentration is greater than 0.25 grain per 100 standard cubic feet, along with the presence of carbon dioxide. *Id.*
[90] *EPA Hydrogen Sulfide Report* at ii.
[91] Lana Skrtic, *Hydrogen Sulfide, Oil and Gas, and People's Health* ("Skrtic Report"), at 6 (May 2006), *available at* http://www.earthworksaction.org/pubs/hydrogensulfide_oilgas_health.pdf, attached hereto as Exhibit 48.
[92] *EPA Hydrogen Sulfide R*eport at III-35.
[93] *Id.* at ii.

example, hydrogen sulfide is emitted as a result of leaks from processing systems and from wellheads in sour gas fields.[94]

Hydrogen sulfide emissions from the oil and gas industry are concerning because this pollutant may be harmful even at low concentrations.[95] Although direct monitoring of hydrogen sulfide around oil and gas sources is limited, there is evidence that these emissions may be substantial, and have a serious impact on people's health. For example, North Dakota reported 3,300 violations of an odor-based hydrogen sulfide standard around drilling wells.[96] People in northwest New Mexico and western Colorado living near gas wells have long complained of strong odors, including but not limited to hydrogen sulfide's distinctive rotten egg smell. Residents have also experienced nose, throat and eye irritation, headaches, nose bleeds, and dizziness.[97] An air sample taken by a community monitor at one family's home in western Colorado in January 2011 contained levels of hydrogen sulfide concentrations 185 times higher than safe levels.[98]

Particulate Matter (PM): PM consists of tiny particles of a range of sizes suspended in air. Small particles pose the greatest health risk. These small particles include "inhalable coarse particles," which are smaller than 10 micrometers in diameter (PM_{10}), and "fine particles" which are less than 2.5 micrometers in diameter ($PM_{2.5}$). PM_{10} is primarily formed from crushing, grinding or abrasion of surfaces. $PM_{2.5}$ is primarily formed by incomplete combustion of fuels or through secondary formation in the atmosphere.[99]

PM causes a wide variety of health and environmental impacts. PM has been linked to respiratory and cardiovascular problems, including coughing, painful breathing, aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death. Sensitive populations, include the elderly, children, and people with existing heart or lung problems, are most at risk from PM pollution.[100] PM also reduces visibility,[101] and may damage important cultural resources.[102] Black carbon, a

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[94] TSD at 2-3.
[95] *See* James Collins & David Lewis, *Report to CARB, Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protections of Children* (Sept. 1, 2000), *available at* http://oehha.ca.gov/air/pdf/oehhah2s.pdf, attached hereto as Exhibit 49.
[96] EPA Hydrogen Sulfide Report at III-35.
[97] *See* Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development*, at 11-14 (July 2011), attached hereto as Exhibit 50.
[98] *Id.* at 21.
[99] *See* EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html, attached hereto as Exhibit 51; BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Final Environmental Impact Statement* ("West Tavaputs FEIS"), at 3-19 (July 2010), *available at* http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html, attached hereto as Exhibit 52.
[100] RIA at 4-19; EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html
[101] EPA "Visibility – Basic Information" http://www.epa.gov/visibility/what.html, attached hereto as Exhibit 53.
[102] *See* EPA, Particulate Matter, Health West Tavaputs EIS, at 3-19; RIA at 4-24.

component of PM emitted by combustion sources such as flares and older diesel engines, also warms the climate and thus contributes to climate change.[103]

The oil and gas industry is a major source of PM pollution. This pollution is generated by heavy equipment used to move and level earth during well pad and road construction. Vehicles also generate fugitive dust by traveling on access roads during drilling, completion, and production activities.[104] Diesel engines used in drilling rigs and at compressor stations are also large sources of fine PM/diesel soot emissions. VOCs are also a precursor to formation of $PM_{2.5}$.[105]

PM emissions from the oil and gas industry are leading to significant pollution problems. For example, monitors in Uintah County and Duchesne County, Utah have repeatedly measured wintertime $PM_{2.5}$ concentrations above federal standards.[106] These elevated levels of $PM_{2.}$ have been linked to oil and gas activities in the Uinta Basin.[107] West Tavaputs FEIS at 3-20. Modeling also shows that road traffic associated with energy development is pushing PM_{10} levels very close to violating NAAQS standards.[108]

3. *EPA must revise and expand the existing performance standards to curb this pollution*

The current NSPS is inadequate and outdated. In 1985, EPA promulgated two separate NSPS for the "crude oil and natural gas production" sector.[109] The first NSPS addresses leaks of VOCs from onshore natural gas processing plants.[110] The second regulates sulfur dioxide emissions from natural gas processing plants.[111] The two standards only address emissions from natural gas processing plants, leaving the majority of emissions from the oil and gas industry unregulated at the federal level.

As we discuss above, EPA is required under Section 111 of the Clean Air Act to "review and, if appropriate, revise" NSPS standards every 8 years.[112] Although more than 25 years have passed since EPA promulgated the NSPS for the oil and natural gas sector, EPA has not reviewed or updated the standard until now.

Not only are the existing performance standards for this industry inadequate, but existing state regulations do not fill the gaps. As we describe below, some states do

[103] UNEP Report at 6; IPCC (2007) at Section 2.4.4.3.
[104] *See* BLM, GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement, at App. J at 2 (Oct. 2010) ("GASCO DEIS")
[105] RIA at 4-18.
[106] GASCO DEIS at 3-12.
[107] West Tavaputs FEIS, at 3-20 (July 2010).
[108] *See* GASCO DEIS at 4-27.
[109] 76 Fed. Reg. at 52,741.
[110] 40 C.F.R. Part 60, Subpart KKK.
[111] 40 C.F.R. Part 60, Subpart LLL.
[112] 42 U.S.C. § 7411(b)(1)(B).

regulate this industry with some rigor (indeed, in a few cases, state rules are more rigorous than EPA's proposed standards), but these regulations are not uniform across the states, nor comprehensive. Eastern states, newly contending with the shale gas boom, are particularly in need of the federal baseline the NSPS must provide, as most of these states do not have adequate air quality rules specific to oil and gas production. Pennsylvania, for instance, does not have regulations that would require reduced emission completions, even though wellhead emissions are primary pollution sources for the industry. To our knowledge, other Marcellus Shale states, including Ohio, New York, and West Virginia likewise lack comprehensive modern air rules to regulate the industry's air quality impacts. EPA rulemaking is thus urgently needed.

Moreover, as EPA's proposed rule demonstrates, there are numerous cost-effective control technologies available to control emissions from this sector, that can and must form the basis for updated performance standards.

II. TECHNICAL REVIEW OF EPA's PROPOSED STANDARDS

As we discuss below, the record before EPA demonstrates that EPA must maintain the stringency of its proposed standards, and in some respects must strengthen them, to comply with the Clean Air Act's rigorous requirements. The proposed standards are based upon practices that are already widespread in the industry, and generally save the industry money by allowing it to capture additional valuable natural gas. By requiring existing industry best practices for many sources, and codifying those practices into law, EPA does not always meet the Act's requirement to force additional control technology innovation. Indeed, the Agency is in several instances not even providing incentives for the development of new control techniques but instead merely bases standards on long-demonstrated and cost-effective systems of emission reduction. For that reason, the proposed standards are in some cases more technology-following than technology-forcing, and are thus unlawfully lenient.

The agency therefore must correct several significant weaknesses in the rules. These flaws fall into several categories. In some instances, the proposed standards are vague and/or unclear. In others, the agency has created unnecessarily broad exemptions to its standards which will allow operators to escape compliance, or which will cause enforcement difficulties. In some other instances, EPA has set standards below the levels which industry can achieve, and must therefore tighten its control standards. Finally, EPA has simply failed to set standards for some sources and facility types at all.

Our review below relies in part on several reports by well-recognized experts, which we incorporate in full by reference. These experts include Dr. Ranajit Sahu, whose report focuses on the engineering data underlying EPA's proposal, Cindy Copeland and Megan Williams, whose report addresses methane and VOC control technologies, Dr. Laurie

Johnson, whose report concerns issues of methane valuation,[113] and Rick Hornby and Dr. Carl Swanson, whose report concerns natural gas pricing.

A. Wellhead Facilities

1. EPA's Proposal

EPA proposes to regulate "gas wellhead facilities," each of which would constitute a "single natural gas well."[114] EPA determined that it was not feasible to set a standard of performance for this category because some pollutants would be emitted in a mixture of water and sand, apparently in ways that would render them impossible to properly channel or measure, *cf.* 42 U.S.C. § 7411(h)(2). It therefore promulgated operational standards, pursuant to section 111(h).[115]

These standards would require, for "each well completion operation with hydraulic fracturing," that the operator conduct "reduced emission" or "green" completions, under which the owner or operator is required to "minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system."[116] Operators would have to use sand traps, vessels, tanks, and separators to "safely maximize resource recovery and minimize releases to the environment" and route all salable gas to a gathering line "as soon as practicable." *Id.* Flowback emissions would be sent to a gathering line "except in conditions that may result in a fire hazard or explosion."[117] Where such conditions exist, operators are to use "[c]ompletion combustion devices . . . equipped with a reliable continuous ignition source."[118]

Two types of wells, "wildcat" and "delineation" wells, may avoid using gathering lines and instead "reduce emissions . . . using a completion combustion device."[119] A wildcat well is "a well outside known fields or the first well drilled in an oil or gas field where no other gas or oil production exists."[120] A delineation well is "a well drilled in order to determine the boundary of a field or producing reservoir."[121]

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[113] Dr. Laurie Johnson, Ph.D, "Comments on The Social Benefits of Methane Reductions from the Proposed Oil and Gas New Source Performance Standards," *Natural Resources Defense Council*, November 17, 2011, attached hereto as Exhibit 249.

[114] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365(a)). Proposed 40 C.F.R. § 60.5365(a) is missing a "which" in the sentence explaining that a gas wellhead facility is a single natural gas well. EPA must correct this error.

[115] *See* 76 Fed. Reg. at 52,758-59.

[116] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).

[117] *Id.*

[118] *Id.*

[119] *Id.* (Proposed 40 C.F.R. § 60.5375(f)).

[120] *Id*. at 52,811 (Proposed 40 C.F.R. § 60.5430).

[121] *Id.* at 52,809.

2. BTSER Determination

a. New Wellhead Facilities

We agree with EPA that some form of reduced emissions completion (REC) constitutes the "best technological system of continuous emission reduction" (BTSER) which has been adequately demonstrated for wellhead facilities,[122] and that emissions standards based on these practices would "reflect the best system of emission reduction . . . adequately demonstrated."[123] We emphatically do not agree, however, that EPA has, in fact, drafted regulations compliant with the BTSER standard. As we discuss below, EPA's proposed regulations have such significant flaws—including impermissible exemptions – that they will not be compliant with section 111 without significant revision.

As the Sahu and Copeland and Williams reports discuss, the record amply supports the broad utility and cost-effectiveness of REC techniques.[124] Furthermore, as EPA explains in the Technical Support Document for this rulemaking (TSD), REC "not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented."[125] EPA estimates that an average green completion results in net *savings* of $5,697 and yield 20.8 tons of avoided VOC emissions per well.[126] In fact, the savings will be even higher because, as we discuss below,[127] EPA underestimated the direct financial benefits of RECs by using an unrealistically low gas price and potentially overstating REC costs.

In light of the practice's financial benefits, industry has widely adopted REC, and several states currently require REC. Colorado, for instance requires "green completion practices" wherever technically and economically feasible,[128] and Wyoming requires green completions in its Jonah Anticline fields and all "Areas of Concentrated Development."[129] According to EPA, "RECs have become a popular practice among Natural Gas STAR production partners," with, as of 2010, thirteen different partners

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[122] *See* 76 Fed. Reg. at 52,758-59, 42 U.S.C. § 7411(h)(1)
[123] 42 U.S.C. § 7411(a)(1).
[124] Cindy Copeland and Megan Williams, *Methane Related Comments on EPA's "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," Proposed Rule* (November 29, 2011*)* attached hereto as Exhibit 54; Dr. Ranajit Sahu, *Comments on EPA Proposed NSPS Rulemaking for Crude Oil and Natural Gas Production, Transmission, and Distribution* (Nov. 2011)at 9-11, attached hereto as Exhibit 55.
[125] TSD at 4-12.
[126] TSD at 4-16 – 4-18.
[127] *See infra* Section VII.
[128] Co. Oil & Gas Conserv. Comm'n ("COGCC") Rule 805(b)(3)(A), attached hereto as Exhibit 56.
[129] Wy. Oil and Gas Production Facilities Permitting Guidance ("Wy. Guidance") at 15, 20, attached hereto as Exhibit 57.

reporting success.[130] EPA Natural Gas Star partners have reported considerable success with REC in a variety of geographical contexts, including:

- BP's implementation of RECs on 106 wells, at both high and low pressures, in the Green River Basin of Wyoming, which resulted in a "conservative" value of gas saved at $20,000 per well.[131]

- Noble Experience's implementation of REC on 10 hydrofractured wells in Oklahoma, with profits of $340,000.[132]

- An anonymous partner company's implementation of REC on 30 wells in Fort Worth, Texas, which resulted in a "conservative" savings of $50,000 per well.[133]

- Anadarko's implementation of REC in the Denver-Julesberg Basin of Wyoming, saving an average of $19,369 per well.[134]

- Chesapeake and Devon's extensive use of green completions in the Barnett Shale (these companies are the two largest producers in the Barnett Shale), constituting 114 of every 115 wells, and 85% of wells, respectively.[135]

We discuss further examples of profitable RECs in our cost discussion below,[136] and industry and EPA literature is replete with examples of successful RECs.[137]

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[130] EPA, *Reduced Emissions Completions: Lessons Learned from Natural Gas STAR Partners* at 1 (2010), available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, attached hereto as Exhibit 58. *See also* EPA, *Reducing Methane Emissions During Completion Operations* (Oct. 24, 2006), attached hereto as Exhibit 59.

[131] *Id.* at 10.

[132] *Id.*

[133] *Id.* at 10.

[134] Anadarko, *Reduced Emission Completions in DJ Basin and Natural Buttes*, EPA Producers Technology Transfer Workshop (May 1, 2008), attached hereto as Exhibit 60.

[135] April 18, 2011 presentation to the Oil and Gas Task Force of the North Texas Clean Air Steering Committee; available at http://www.nctcog.org/trans/committees/ntcasc/OGTF/041811/Items3BC.pdf, attached hereto as Exhibit 61.

[136] *See infra* Section VII(B)(2)(a).

[137] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (collecting examples of profitable RECs), attached hereto as Exhibit 62; EPA, PRO Fact Sheet 703, *Green Completions* (documenting use of RECs by BP & ConocoPhilips), attached hereto as Exhibit 63; EPA, Natural Gas STAR Lessons Learned, *Reduced Emissions Completions* (endorsing RECs as a profitable and effective control technique); John Corra, Director, Wyoming Department of Environmental Quality, *Emissions from Hydrofracking Operations and General Oversight Information for Wyoming* (July 13, 2011) (describing successful implementation of state-level REC requirement), attached hereto as Exhibit 64; Chesapeake Energy, *Air Emissions and Regulations*(July 2011) (stating that Chesapeake uses green completions at its wells), attached hereto as Exhibit 65;Chesapeake Energy, *Greenhouse Gas Emissions* (last visited Nov. 2011) (stating that "green completions . . . have been Chesapeake's largest contributor of emissions

In short, RECs generate profits, reduce emissions, and allow for more salable gas and condensate. RECs therefore are the *minimum* requirement for BTSER for new and modified wells. No lesser requirement would be compliant with section 111. Yet, in several regards, EPA has failed to impose this level of control, as we will shortly discuss.

b. Modifications

We also support EPA's recognition that recompletions of fractured or refractured wells drilled prior to August 23, 2011 constitute modification under section 111(a). These activities are a very large source of emissions, and their control under the proposed standards of performance is a key component of EPA's proposal. There is a definitional flaw in EPA's proposed language, however, which we discuss below.

Under part 60, subpart OOOO, 40 C.F.R. § 60.5430, EPA sets forth the following regarding modifications in the oil and gas sector:

> any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification*.[138]

This provision, to the extent that it defines hydraulic fracturing operations as modifications, is in keeping with section 111's definition of modification. But EPA must modify it in two regards. First, it must make pellucidly clear that EPA intends to override any conflicting regulatory definitions of modification. Second, it must revise the definition to remove undefined terms.

<u>First,</u> The Clean Air Act defines "modification" under 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."[139] As EPA points out, during the fracturing or refracturing of an existing well, "physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the

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reductions), attached hereto as Exhibit 66; EnCana, *Environment Health and Safety Commitment* (describing EnCana's efforts to reduce flaring and venting at its wells), attached hereto as Exhibit 67.

[138] 76 Fed. Reg. at 52,810 (emphasis added).

[139] 42 U.S.C. § 7411(a)(4) (emphasis added); *see also* 40 C.F.R. § 60.14(a) ("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.").

completion operation."[140] For purposes of NSPS, an emissions increase occurs whenever emissions after a physical change are greater than emissions immediately prior to the change.[141]

Not only do hydraulic fracturing activities meet the statutory definition of modification, but EPA's proposal in proposed 40 C.F.R. § 60.5430 that recompletions of these wells are modifications for the purposes of this industry overrides any conflicting provisions in the general NSPS definition of modification contained in 40 C.F.R. § 60.14.[142] Thus, to the extent that any of the exemptions contained in 60.14(c) would otherwise prevent recompletions and refracturing from being considered modifications, they would be overridden by the specific oil and gas provision.

While the proposed 60.5430 is sufficient to override any conflicting portions of 60.14,[143] we encourage EPA to clarify the regulatory language by explicitly invoking § 60.14(f) and explaining that the capital expenditure test codified at 40 C.F.R. § 60.14(e)(2), for example, does not apply.[144]

<u>Second</u>, EPA is wrong to define a modification in this context as "each recompletion of a fractured or refractured existing gas well" because "recompletion" is an undefined term and so will lead to confusion. The relevant modification – and source of increased emissions – in this context is, in fact, the hydraulic fracturing operation at the well. EPA must simply say so.

So the revised section 60.5430 would read:

> *Modification* means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. *For the purposes of this subpart, each hydraulic fracturing operation at an existing gas well is considered to be a modification regardless of any provision of 40 C.F.R. § 60.14(e) stating regulatory exemptions to the term "modification*.

[140] 76 Fed. Reg. at 52,759; *see also* TSD at 4-1 – 4-2.
[141] *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 910, 915 (7th Cir. 1990) (citing CAA § 111(a) and 40 C.F.R. § 60.14(b)(2)), attached hereto as Exhibit 68.
[142] *See id*. § 60.14(f). EPA previously has relied on 60.14(f) to depart from its general regulatory definition of modification by delineating what constitutes a modification under a sector-specific subpart of the NSPS "to eliminate ambiguity." *See* 73 Fed. Reg. 35838, 38856 (June 24, 2008) (defining what constitutes a flare modification for Petroleum Refineries, subpart Ja), (codified at 40 C.F.R. § 60.100a(c) (2010)).
[143] We do not concede that EPA' regulatorily-created "exemptions" from the statute's broad modification definition are legal.
[144] *See also* 40 C.F.R. § 60.2 (defining "capital expenditure").

3. Further Critiques

We support EPA's proposal to require "reduced emission" or "green" completions. Nonetheless, there are three general areas in which the proposal must be strengthened. EPA must at a minimum (1) clarify and strengthen the language of the proposed standard; (2) extend the REC requirement to many well types that are currently excluded from the proposed standard; and (3) enhance standards for pit flaring.

a. Definitional Issues

The proposed regulation uses a number of undefined or poorly defined terms. As a result of the needlessly complicated wording, the proposed regulatory text fails in three regards. It fails to clearly and inclusively define hydraulically fracturing. It fails to clearly apply EPA's standards to fractured and refractured existing wells. And it fails to articulate comprehensible and enforceable standards. EPA must correct these failings. As EPA has explained in the context of permit requirements, source obligations must be practically enforceable, and language that is vague, ambiguous, or otherwise unclear creates lack of clarity as to legal obligations. The same concern obviously attaches to the underlying regulations as well.

First, EPA's core "hydraulic fracturing" definition must be revised. EPA's proposal defines the process as:

> The process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.[145]

The definition is unclear, which will lead to enforcement problems, and may also be underinclusive. EPA must revise it.

The lack of clarity arises in two ways. First, EPA defines fracturing as involving a "high" rate of "extended" back flow. These are relative terms, and are not defined in the text. Operators and enforcement staff are highly likely to differ over what constitutes high or extended flows.

The second clarity problem arises because the definition states that the process takes place by directing chemicals "to penetrate [various formations] that involve high rate, extended back flow *to expel fracture fluids and sand during completions and well workovers*." By focusing on the *purpose* of the activity, rather than its effects, EPA has inadvertently left room for debate as to whether a given well operation is intended "to penetrate" formations or has some other goal. Worse, the proposed text muddles the

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[145] 76 Fed. Reg. at 52,810. (Proposed 40 C.F.R. § 60.5430).

purpose at issue, as it refers both to processes intended "to penetrate" formations and "to expel fracture fluids and sand during completions and well workovers." This second "purpose" is not a goal of fracturing operations, because backflow is not intended to do anything in particular; it is a *consequence* of pressure in the well itself caused by the fracturing process (which itself is not intended "to expel fracture fluids and sand").

EPA can, and must, resolve all of these problems by revising the definition to avoid discussions of the magnitude of backflow and the purpose of the operation. It can do so because all hydraulic fracturing, as far as we are able to determine, involves perforating the casing of the well with explosive charges to allow fracturing fluids to enter a formation. EPA can therefore use the moment of casing perforation as the trigger point for NSPS applicability.

The underinclusivity problem, next, arises because fracturing may not always be conducted with water. Fracturing using foams,[146] gases, [147] or hydrocarbons[148,149] is also possible, and foam fracturing is used in U.S. plays. Although these methods may result in less immediate flowback, they may still generate significant produced water, which is a source of VOCs and methane, and may also result in increased emissions, relative to conventional wells, during the hydraulic fracturing process. EPA must investigate whether emissions from these processes are significant. If so, it must modify its definition to refer to these processes as well, or, to encompass other potential processes, could also refer simply to "pressurized substances," which "may" include water.

The fully corrected definition would, in other words, read:

> The process of directing pressurized substances, which may contain foam, gases, water, hydrocarbons, proppant, and any added chemicals, into a well whose casing is perforated, allowing these substances to leave the well bore.

[146] *See, e.g.*, EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (2004) at 4-5 – 4-6 (discussing these foam gels), attached hereto as Exhibit 69; Ken Little, Knoxville News, "Nitrogen-heavy gas drilling method common in Tenn." (Dec. 5, 2010), available at http://www.knoxnews.com/news/2010/dec/05/nitrogen-heavy-method-prevalent-in-tenn/?print=1, attached hereto as Exhibit 248.

[147] 76 Fed. Reg. at 52,757.

[148] *See, e.g.*, Hans. D. Linhardt, "LNG and LIN can be Alternative Fracturing Methods for Shale Gas" (Dec. 18, 2009), available at https://www.gplus.com/natural-resources/insight/lng-and-lin-can-be-alternative-fracturing-methods-for-shale-gas-45488, attached hereto as Exhibit 70.

[149] *See, e.g.*, Anna Driver, Reuters, "Propane Substitutes for water in shale fracking" (Nov. 22, 2011), available at http://www.reuters.com/article/2011/11/22/us-shale-propane-idUSTRE7AL1ML20111122, attached hereto as Exhibit 71.

Second, as we have indicated above, EPA's proposed language does not effectuate its intent to apply its standards to "completions associated with fracturing or re-fracturing of existing gas wells."[150]

We have already explained why EPA's definition of "modification" must be revised to refer simply to "hydraulic fracturing operations" at existing wells. EPA must also address a second definitional problem, which is that its proposed applicability language for its REC standard would attach that requirement to "each well completion operation with hydraulic fracturing."[151] This language does not clearly refer to fracturing and refracturing at *existing wells*. Stepping through the definitions, a "well completion operation means any well completion or well workover occurring at a gas wellhead affected facility."[152] A well "completion," next, is defined with reference to "newly drilled" wells, so EPA must have intended the "workover" term to encompass refracturing as a modification at existing wells. Indeed, the only explicit discussion of well modifications in the proposed regulation is the statement that a "workover" is a modification. [153] But the workover term itself is not defined, and is vague.[154] The result is that EPA has not clearly applied REC requirements to fracturing and refracturing at existing wells. [155]

A far simpler and more effective solution, which we urge EPA to adopt, is to amend proposed 40 C.F.R. § 60.5375 to impose REC and associated requirements on each "well completion, and any other hydraulic fracturing operation," using the fracturing of the well casing itself as the trigger point to apply standards, and as the indicator that a "modification" has occurred. With this definitional change, coupled with the revisions to the modification section we discuss above (which would make clear that each fracturing event is a modification), such operations at existing wells will be covered by the standards, as they must be.

Third, the proposed standard itself is dangerously unclear. EPA's proposed standard requires operators to "minimize" emissions by storing and then routing to pipelines as much recovered liquid and gas as possible, with the backstop of flaring or venting the remaining emissions, and to "minimize" releases to the environment.[156] But it does not define what "minimize" means, or how EPA will know when an operator is not "minimizing" in accordance with the standard. Likewise, though EPA provides that

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[150] 76 Fed. Reg. at 52,745-46.
[151] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. §60.5375).
[152] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).
[153] As we discuss above, EPA should clarify that by refracturing, recompletion or workover is a modification pursuant to CAA § 111(a) *per se*, such that the capital expenditure test adopted by EPA at 40 C.F.R. § 60.14(e)(2) does not apply. *See also* § 60.2 (defining "capital expenditure"), § 60.14(f) (EPA may adopt "special provisions" under part 60 that supercede the general provisions of § 60.14).
[154]
[155] We note that EPA's "hydraulic fracturing" definition also uses the undefined "workover" term. EPA must strike that term there as well, if it does not define it.
[156] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)).

resource recovery is to be "safely maximize[d]," it does not define that term either. Nor does EPA set any limit on how much gas may be flared, rather than captured, stating only that gas which "cannot be directed" to a gathering line is to be sent to flares. Similarly, salable gas is to be routed to a gathering line as "soon as practicable," a term that leaves considerable room for dispute. EPA must tighten these definitional holes.

EPA must resolve these problems by stating clearly that, except in the very narrow defined circumstances where safety considerations so warrant, *all* emissions from the wellhead must be either captured or flared, not vented, and that flaring is a disfavored secondary option, to be used only when it is not possible to capture the wellhead emissions for safety reasons. In doing so, EPA must avoid the use of the "maximize" and "minimize" terms which will otherwise cause substantial difficulties.

It must do so by revising proposed 40 C.F.R. § 60.5375(a) to read as follows, in pertinent part[157]:

> … (1) You must capture all gases and liquids emanating from each well subject to these regulations at all times following perforation of the well casing until flowback has ceased.
>
> (2) You must route all recovered liquids into storage vessels and route all recovered gas into a gas gathering line or collection system, except as specified in paragraph (a)(3).
>
> (3) Where direction of recovered gases or liquids into storage vessels or gas gathering lines is not possible due to material safety hazards, you must direct these materials to a completion combustion device, except in conditions that pose a material risk of fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

EPA must also add a requirement that operators record a specific reason for flaring or venting in lieu of capture, to the record-keeping requirements in the proposed rule, and provide advance notice of flaring or venting to permitting authorities where feasible.[158]

Finally, EPA must clarify the proposed regulation to reflect EPA's intention as stated in the preamble that the Administrator must be notified *before* well completions occur. The preamble states that "the proposed NSPS requires 30-day *advance* notification of each completion or recompletion of a hydraulically fractured gas well."[159] The proposed regulation, however, merely states that an operator must "notif[y] the Administrator within 30 days of the commencement of the well completion operation."[160] Read

[157] We recommend putting paragraph (a)(2) in the proposal before paragraph (a)(1), and have done so here, because (a)(2) describes how operators must recover the "recovered liquids" and "recovered gas" referred to in (a)(1).
[158] *See* 76 Fed. Reg. at 52,808 (Proposed 40 C.F.R. § 60.5420(c)(1)(iii)(A)).
[159] *Id.* at 52,749.
[160] *Id.* at 52,805 (Proposed 60 C.F.R. § 60.5410(a)(1)).

literally, the proposed regulation would be satisfied so long as the Administrator was notified no later than 30 days *after* the completion. EPA further requests comment regarding a two day follow-up notification.[161] We agree that if the 30-day advance notification does not commit the operator to a precise date for completion, once the date is determined, then follow-up notification (at least two days prior to commencement of completion operations) must be required, to allow for on-site inspection.

b. Exclusions

EPA has improperly excluded several classes of wells that can contribute to harmful levels of air pollution.

<u>First</u>, EPA proposes to exempt "wildcat" and "delineation" wells from the REC requirements (but not from the flaring standards) even when they are hydraulically fractured high flowback gas wells in tight sand or shale formations. The proposed regulations define a "wildcat well" as "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[162] A "delineation well" is "a well drilled in order to determine the boundary of a field or producing reservoir."[163] EPA asserts without support that "[b]ecause these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing."[164]

EPA does not support its conclusion and the exemptions unnecessarily and impermissibly allows excess emissions. Moreover, the exclusion invites enforcement difficulties, as operators and enforcement staff may dispute whether a well fits into either category, as the precise boundaries of a field – and the purpose for which a well is drilled – may be unclear.

To avoid these difficulties, and to extend the REC standards to as many wells as possible, EPA must eliminate its "delineation" well exemption, and sharply narrow its "wildcat" well exemption.

The "delineation" well concept is readily subject to misuse, as it turns on both the operators intent (e.g., was the well drilled "to determine" a boundary?), and upon the "boundary of a field or producing reservoir," which is a difficult and subjective line to draw. In a sense, each well drilled in a given field helps define that field's boundaries and extent, opening this exemption to confusion and gamesmanship. EPA must eliminate it.

[161] *Id.* at 52,749.
[162] *Id.* at 52,811 (Proposed 40 C.F.R. § 60.5430).
[163] *Id.* at 52,809.
[164] 76 Fed. Reg. at 52,759.

In doing so, EPA will be following the lead of the state of Wyoming, which has determined that, in areas covered by its green completion requirements, "lack of a pipeline connection due to reasons other than wildcat, exploratory or step-out well classification" does not excuse avoiding an REC.[165] Wyoming, in other words, lacks a "delineation" well exemption – the wells which it exempts are all in remote, undeveloped areas, unlike "delineation" wells, which are drilled in existing fields.[166] Remoteness is the hallmark. As EPA's own TSD explains:

> The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[167]

EPA must follow suit. The goal must be to define a narrow, easily-recognized category of exempt wells which truly cannot construct or access a gathering line, a subset which is likely quite narrow because, as EPA acknowledges, "[i]n instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC."[168]

We urge EPA, therefore, to define wildcat well narrowly, and ensure that only wildcat wells which cannot access a gathering line receive an exemption. To do so, it must first narrow its wildcat well definition, which as proposed applies to "a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."[169] Because multiple wells may be drilled "outside known fields," and companies can and should plan to capture emissions from later wells, EPA must narrow this exemption to mean "the *first* well *drilled* outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists."

Next, EPA must make clear, in Proposed 40 C.F.R. § 60.5375, that these wildcat wells can only be exempted from an REC if they are, in fact, not near a gathering line. EPA must set a reasonable distance from a gathering line below which even wildcat wells will be required to conduct an REC.

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[165] Wyoming Department of Environmental Protection, Green Completion Permit, available at: http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf, attached hereto as Exhibit 72.

[166] Wyoming, for instance, defines "wildcat" wells as "wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive." Wy. Oil & Gas Conserv. Comm'n Rule 1 §2(iii)., attached hereto as Exhibit 73.

[167] TSD at 4-14.

[168] *Id.*

[169] 76 Fed. Reg. at 52,809 (Proposed 40 C.F.R. § 60.5430).

EPA must consider three miles as such a reasonable distance. A typical Marcellus well, for instance, costs $3 million to drill,[170] while the costs of building a three-mile long gathering line to that well are far less, and, if the well is productive, eclipsed by the revenues the well produces.[171] If EPA deems this distance is not reasonable, it must explain why not, and propose an alternative distance.

Finally, we urge EPA to collect the information necessary to determine whether all wells, including wildcat wells, can use gas that would otherwise be flared as fuel for onsite operations, and the emissions consequences of such a diversion. If onsite fuel use produces more limited secondary environmental impacts than flaring, it must be required, where possible, and may be an especially attractive option for wells that are not near a gathering line.

Second, EPA needs to include hydraulically fractured oil wells that produced associated gas in its standards. These wells are excluded under the proposed standard, which applies only to gas wells.[172] EPA acknowledges that hydraulic fracturing at oil wells creates a period of flowback with increased natural gas and VOC emissions.[173]

EPA must require that the maximum amount of gas produced from hydraulically fractured oil wells during both flowback and normal production, be captured rather than vented or flared. Recent developments raise questions about EPA's estimates of low emissions from these wells. Specifically, the *New York Times* reports that very large amounts of gas are being flared daily in the hydraulically fractured Bakken Shale play in North Dakota. The *Times* reports gas discharges of over 150 million cubic feet per day being flared in that field, as **Figure 2**, on the right of this page, indicates.[174] This huge volume of flaring is undoubtedly producing significant air pollution, and is avoidable with RECs and connection to gas gathering lines.

This report, drawn from North Dakota government data, very strongly argues that REC, and continuing gas capture from

[170] PennState Live, *Unconventional natural gas reservoir could boost US supply* (Nov. 2008), available at http://live.psu.edu/story/28116, attached hereto as Exhibit 74.
[171] *See, e.g.*, Interstate Natural Gas Association of America, *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030* (2009) (offering pipeline cost figures) at 48, attached hereto as Exhibit 75.
[172] 76 Fed. Reg. at 52,757.
[173] 76 Fed. Reg. at 52,757, TSD §§ 4.1.1 – 4.1.2.
[174] *See* Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (Sept. 28, 2011), attached hereto as Exhibit 76.

producing oil wells, would be economically and environmentally beneficial.[175] Although producers may have to focus on expanding gathering line construction to prevent this waste, other options, including reinjection, must be explored. EPA must drive the process with a strong performance standard for such wells. As a start, EPA must require the productive capture and routing to a pipeline of vented associated gas at oil wells whenever natural gas gathering pipelines are within a reasonable distance (three miles, as we explain above) to an affected oil well. If reinjection, productive use onsite, or capture for sale of gas cannot be required, then EPA must ensure that emissions from flares are minimized.

Third, EPA is apparently considering exempting some coalbed methane wells from its REC requirement. EPA is concerned that low pressure in some coalbed methane reservoirs may present a technical barrier for performing a REC.[176] We have not found data in the record regarding the pressure in coalbed methane formations or demonstrating that these pressures render RECs infeasible. Indeed, BP has been using green completions in coalbed methane formations in the San Juan Basin for at least seven years.[177] Because RECs are possible in coalbed methane, EPA must not exempt coalbed methane wells from the NSPS's REC requirements.[178]

If EPA does, however, opt for an exemption in this area, it must ensure that the exemption is keyed specifically to the feasibility of conducting an REC at a specific coalbed methane well, and is not a blanket exemption for all such wells. Any exemption must be subject to public notice and comment.

Fourth, we are concerned that EPA has proposed no controls for other well-related activities. Liquids unloading and other well cleanup activities are dominant methane emissions sources, according to EPA's most recent greenhouse gas inventory.[179] Because VOCs are generally co-emitted with methane at natural gas production wells, we expect these activities to be significant VOC sources as well. Cost-effective technologies, including plunger lifts, are available to control these VOC emissions, and investments in such measures can be recouped within a year.[180] Yet, EPA has proposed no standards requiring these effective and widely-used measures. This decision is not consistent with EPA's obligations under section 111, as it fails to impose standards based upon an available and widely-demonstrated technology that could significantly reduce sector VOC emissions. It is our understanding that EPA believes technologies like

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[175] *See* Copeland and Williams Report at 18-20 (documenting these emissions).
[176] *See* 76 Fed. Reg. at 52,758.
[177] *See* Sahu Report at 12.
[178] *See also* Copeland and Williams Report at 15-16 (describing REC performed in Texas, Wyoming, and Colorado at low pressure well sites).
[179] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 (pp. A-149 – A-153), attached hereto as Exhibit 77.
[180] *See, e.g.* Sahu Report at 8, Copeland and Williams Report at 17-18.

plunger lifts are already in use at many facilities, and even a cursory investigation demonstrates that plunger lifts are, indeed, popular emissions control technology.[181]

Thus, BTSER controls must be based, at a minimum, upon plunger lifts. We note that EPA originally appears to have intended to require such activities, as "plunger lift system" is defined in the definitions section of the rule.[182] EPA must follow through. EPA must require that new wells drilled be equipped with plunger lifts or similar technology to reduce VOC emissions if they fill up with liquids. Furthermore, liquids unloading, a physical change to a gas well which substantially increases emissions of VOC from the well, must be treated as a modification of that well. This treatment is consistent with, and mandated by, EPA's recognition, in the context of hydraulic fracturing context, that such physical changes are modifications. Precisely the same legal logic applies here. EPA must therefore clarify its modification definition to include liquids unloading events, and develop standards to cover these events which, as we have demonstrated, must be based upon plunger lift technology, at a minimum.

c. Managing Flaring

EPA must also strengthen its flaring requirement. The proposed standard would channel emissions which it is not feasible to capture to a "completion combustion device, except in conditions that may result in a fire hazard or explosion."[183] These combustion devices "must be equipped with a reliable continuous ignition source over the duration of the flowback."[184] This standard is a useful start, but it does not minimize emissions risks.

First, as described above, EPA must tighten the requirements to capture gas, so it is not flared (or vented). As part of this tightening, EPA must require that operators document the reason that capture does not occur and venting *or flaring* occurs.

[181] *See, e.g.*, Methane to Markets, Oil & Gas Subcommittee Technology Transfer Workshop, *Reduced Emission Completions/Plunger Lift and Smart Automation* (Jan. 28, 2009) (describing successful plunger lift projects); INGAA Foundation, *Activities to Reduce Greenhouse Gas Emissions from Natural Gas Operations* (2000) at 33 (recommending plunger lifts),attached hereto as Exhibit 78; BP, *Plunger Well Vent Reduction Project* (2006) (describing "great success" with plunger lifts), attached hereto as Exhibit 79; IPS, *Plunger Lifts* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 80; Lufkin International Lift Systems, *Plunger Lift Systems* (last visited Nov. 2011) (vendor offering plunger lift systems, attached hereto as Exhibit 81;Weatherford, *Plunger Lift System Overview* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 82; Production Lift Systems, Inc, *Plunger Lift Principles* (last visited Nov. 2011) (vendor offering plunger lifts), attached hereto as Exhibit 83
[182] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[183] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5375(a)(3)).
[184] *Id.*

Second, EPA must tighten its venting exemption, which allows operators to avoid venting in conditions "that may result in a fire hazard or explosion." Safety is certainly an important consideration, but this language is vague – many conditions "may" have some degree of hazard, especially when dealing with inherently flammable gas. To avoid this problem, while retaining legitimate safety precautions, EPA must revise this passage to require combustion except in conditions "that pose a material risk of fire hazard or explosion" or similar.[185]

Third, EPA must enhance flaring requirements. The proposal allows use of a "completion combustion device," defined as "any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers."[186] EPA acknowledges that such devices will result in increased NO_x, carbon monoxide (CO) and PM emissions.[187] To our knowledge, there are no published studies on the emissions of pit flares consuming raw natural gas under field conditions. Such studies exist for refinery flares, but they may not be applicable due to the much more narrow operating conditions as opposed to pit flares. In the absence of appropriate studies, anecdotal evidence suggests that pit flares can emit significant amounts of NO_x, CO, PM (including black carbon), VOC, and methane as a result of incomplete combustion and other by-products of combustion as a whole. EPA must issue an information collection request under section 114 of the Act to gather data on this dangerous class of flares, and must also conduct field studies or sponsor field measurements of emissions from pit flares as operated in the oil and gas industry in order to quantify the public health and welfare impacts from this type of flaring.

EPA acknowledges that in practice, combustion at the wellhead is "rather crude, consisting of a horizontal pipe . . . fitted with a continuous ignition source and discharging over a pit near the wellhead."[188] This is because the flowback stream includes "periods of water, condensate and gas" that cannot be directly routed to a traditional control device.[189] EPA must minimize the use of these inefficient and polluting pit flares.

To reduce these pollutants, the proposal must require use of enclosed combustion devices where possible. In an enclosed combustion device, the flame is enclosed in a box at ground level and thus is not affected by the wind, resulting in higher combustion efficiency. An enclosed flare has many advantages including nonstructural support (ground level), straightforward erection, easy maintenance, negligible operating costs,

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[185] We have incorporated this language into our suggested revisions to Proposed 40 C.F.R. § 60.5375, above.
[186] 76 Fed. Reg. at 52, 809 (Proposed 40 C.F.R. § 60.5430).
[187] *See* 76 Fed. Reg. at 52,758; TSD at 4-20.
[188] 76 Fed. Reg. at 52,757-58.
[189] *Id.*

invisible flame, and low noise emission. The disadvantage is that they require considerable space and long interconnecting piping.

EPA also must consider the feasibility of requiring use of separators, dehydrators, and related equipment to render this stream suitable for less crude flaring devices with better pollution control characteristics.[190, 191] Such modifications would allow EPA to apply the flaring efficiency standards of 40 C.F.R. § 60.18 to field flaring operations. Although we understand that EPA is concerned that these standards may be difficult to apply to field flares as written,[192] the 98%-99% control efficiencies of well-managed flares,[193] are very likely significantly superior to the current performance of pit flares. Indeed, EPA's own methane emissions guidance documents discuss pipe flaring at well sites with 99% control efficiencies achieved through proper engineering.[194] By adding requirements to separate and dehydrate "multiphase slug flow," EPA can require well-managed flares.[195] It must do so.

B. Pneumatic Controllers

1. EPA's Proposal

EPA proposes to treat each pneumatic controller as an affected facility for NSPS purposes.[196] A "pneumatic controller" is "an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature."[197]

The proposed standard generally requires that each pneumatic controller at a natural gas processing plant "must have zero emissions of natural gas" while all other controllers "must have natural gas emissions of no greater than 6 standard cubic feet per hour."[198] There is an important exemption to this requirement. If an operator can demonstrate that "the use of a high bleed device is predicated," they will be exempt from the standards.[199] The proposal does not define "predicated."

2. BSER Determination

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[190] Sahu Report at 11-12.
[191] By adding these requirements to § 60.5375(a)(3), they would apply both to residual gas that could not be routed to a gathering line despite a REC and also in situations where a REC was infeasible.
[192] *See* TSD at 4-19.
[193] *See* Copeland & Williams Report at 21-22.
[194] EPA-600/R-96-080f, GRI-94/0257.23 June 1996 "Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary," p. 24, attached hereto as Exhibit 84.
[195] *See* 76 Fed. Reg. at 52,759; Copeland & Williams Report at 21-22.
[196] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5365).
[197] *Id*. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[198] Proposed 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390).
[199] *Id*.

We generally agree with EPA that no-bleed and (where necessary) low-bleed controllers constitute BSER for this facility type. The TSD compellingly demonstrates that controllers are a major emission source, and that the cost of control for these emissions is reasonable.[200] VOC emissions from a single high-bleed controller in the production sector reach 1.92 tons per year,[201] and thousands of controllers are installed annually.[202] The incremental cost of a low-bleed controller is just $165,[203] and no-bleed instrument-air systems are also manageably inexpensive.[204] According to EPA, low-bleed controllers in the production sector alone would *save* the industry over $20 million in the first year the rule becomes effective, with increasing savings in subsequent years.[205]

We strongly support the use of this effective, inexpensive, and profitable control technology as the basis for EPA's standards.[206] However, as we discuss below, EPA's proposed regulations do not implement the statute's requirements appropriately, setting illegally high emissions limits and allowing broad exemptions from the rules. Unless EPA corrects this error, its standards will not comply with section 111's mandates.

EPA did, however, properly include each pneumatic device in the proposed NSPS as an affected facility.[207] EPA also correctly concluded that each installation of a new pneumatic device is construction subject to the NSPS.[208] This conclusion is necessary and appropriate from a policy standpoint, and fully supported as a legal matter.

EPA regulations focus on the practical ability to apply control technology to a pollution source, defining "affected facility" as "any apparatus to which a standard is applicable."[209] EPA correctly notes that a pneumatic device is an "apparatus."[210] It is also clear that each installation of a new replacement pneumatic device is construction subject to the NSPS. The regulations define "construction" as "fabrication, erection or installation of an affected facility."[211]

Furthermore, these facilities are significant sources of emissions nationwide. As EPA stated in the TSD:

[200] *See* TSD at Ch. 5.
[201] *Id.* at 5-6
[202] *Id.* at 5-8
[203] *Id.* at 5-15
[204] *See id.* at 5-25
[205] *Id.* at 5-25.
[206] *See also* Sahu Report at 15-18 (detailing emissions rates); Copeland & Williams Report at 32-34. (documenting emissions reductions).
[207] *See* 76 Fed. Reg. at, 52,761.
[208] *Id*.
[209] 40 CFR. § 60.2.
[210] *See* 76 Fed. Reg. at 52,761.
[211] 40 CFR § 60.2 (2010).

> In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[212]

EPA estimates that a total of 17,124 new pneumatic devices will be installed each year emitting roughly 32,747 tpy of VOCs, 118,054 tpy of methane and 1,237 tpy of HAPs.[213]

It is important to note that the above figures for pneumatic devices represent only new incremental installations of that equipment. Although the proposed regulation will require that pneumatic devices installed after August 23, 2011 *as replacements of existing equipment* comply with the NSPS, the above figures do not include any estimate of the number of replacement devices or the emissions reductions that will occur as a result of their compliance with the NSPS.

3. Critiques

EPA's proposal must be improved by limiting an exemption for high-bleed devices, by extending the instances in which no-bleed devices are used, by defining "low-bleed" consistently with modern industrial practice, and by extending the standards to all pneumatic devices, including pneumatic pumps.

a. Limit The "High-Bleed" Exemption

EPA suggests that "[t]here may be situations where high-bleed controllers . . . are necessary due to functional requirements, such as positive actuation or rapid actuation."[214] It thus proposes to allow operators to "demonstrate, to the Administrator's satisfaction, that the use of a high-bleed device is predicated."[215] This demonstration "may include, but is not limited to, response time, safety and actuation."[216] This exemption is vague, will allow for excessive emissions, and is not properly enforceable.

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[212] TSD at 5-1.
[213] *See* TSD, Table 5-4 at 5-10.
[214] 76 Fed. Reg. at 52,761.
[215] 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a)),
[216] *Id.*

Initially, if EPA retains such an exemption at all, it must define the precise terms under which it can be granted. If there are particular circumstances where a particular high-bleed rate is *necessary* – not "predicated," which is an impermissibly unclear term – EPA must set out those circumstances in regulatory text, rather than providing a vague, non-exclusive list of qualities, like "safety," that any operator may cite in an attempt to avoid the standard. Instead, EPA must define particular requirements that only high-bleed controllers can meet, and require operators to prove that such circumstances are present before an exemption is granted. Unless EPA specifically defines the narrow circumstances in which it will consider allowing for excessive emissions, the exemption has the potential to overwhelm the rule.

Further, EPA must limit the upper bound of the exemption. As drafted, it allows operators to avoid *any* restrictions on the bleed rates of their high-bleed pneumatic controllers. But even the limited class of necessary high-bleed controllers must not be allowed to emit without limit. EPA must therefore draw a hard line for emissions rate above which no exemption will be granted.

EPA must also define the process by which such an exemption would be granted. It needs to specify when an operator must apply for an exemption, how it shall apply – by letter to the Administrator, for instance – how EPA will consider such requests, and how the public may be involved. The public, in particular, has a vital interest in such exemptions: Pneumatic controllers are a major source of harmful VOCs, and so directly implicate public health. Members of the public must be able to comment upon, and challenge, EPA's exemption decisions before the Environmental Appeals Board or a similar body. EPA has provided for such appeal rights in other air quality rulemakings, including in rulemakings focused solely on emissions *monitoring*.[217] Surely, such an appeal right is all the more important in rules focused upon emissions *control*.

b. Extend the Use of No-Bleed Controllers

EPA proposes to base its standard on the use of no-bleed instrument air systems only in natural gas processing plants because it believes that the electricity needed to power these systems will not be available in other settings.[218] This assumption is not supported by data in the record.

Natural gas is now produced in many developed areas, such as in Fort Worth, Texas, where significant production exists within the city borders, and southwestern Pennsylvania, in the vicinity of Pittsburgh. As a result, many pneumatic devices currently installed where electricity is readily available, and emissions of natural gas

[217] *See, e.g.*, 75 Fed. Reg. 76,060, 75,067 (Dec. 1, 2010) (revising EPA appeal provisions to allow members of the public to challenge EPA's approvals of certain greenhouse gas monitoring provisions before the Environmental Appeals Board), attached hereto as Exhibit 85
[218] 76 Fed. Reg. at 52,760.

from bleed devices, snap-acting pneumatics, and other pneumatic equipment (chemical injection pumps, etc.) are released in proximity to local populations.

EPA must set a zero-emissions standard based upon no-bleed pneumatic controllers when electricity is available within a reasonable distance, particularly when multiple devices are clustered within a single area.

For remote locations, as the Copeland and Williams report demonstrates, based upon EPA's own data, no-bleed systems are regularly being used in some instances where grid electricity is not available. Solar-powered controllers, fuel-cell powered controllers, and mechanically-controlled devices are all being used in the field. Most notably, BP reported using solar power panels to replace gas-powered devices, with a payback period of just four years.[219] Copeland and Williams also demonstrate that Colorado and Wyoming require production sector no-bleed systems, where feasible. These technologies may well constitute BSER for a broad class of production systems.

EPA must find as much and set a zero emissions standards based upon no-bleed devices wherever electricity, either from the grid or from field power sources, is available within a reasonable distance from the facility. To do so, it could structure the rule in ways parallel to its "high-bleed" exemption by establishing a rebuttable presumption that no-bleed devices must be used, except where low-bleed devices are necessary because no-bleed devices cannot feasibly be installed.

c. Properly Define "Low-Bleed"

EPA uses a 6 scf per hour bleed rate to define "low-bleed" controllers.[220] But, as the Sahu report discusses, this bleed rate, drawn from twenty-year old documents, is far higher than what modern technology can achieve in many circumstances.[221]

EPA itself states that "low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh."[222] Put differently, EPA apparently acknowledges that the *least* effective low-bleed device "on the market today" has an emission rate that is 1 scfh *lower* than the 6 scfh standard it proposes to set.

A 6 scfh standard therefore cannot constitute BSER for this facility type. We remind EPA that BSER is to be set based upon "what may be fairly projected for the regulated future, rather that the state of the art at present."[223] EPA has not even adopted a standard based upon "the state of the art at present," much less what the regulated future may hold.

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[219] *See* Copeland and Williams Report at 34-36.
[220] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(c))
[221] Sahu Report at 15-16.
[222] TSD at 5-3.
[223] *Lignite Energy Council v. U.S. EPA*, 198 F.3d at 934.

Instead, a more carefully-drawn standard is warranted. Different bleed rates among pneumatic devices correspond to different functions for those devices. As EPA recognizes, higher bleed rates may be associated with devices with shorter response times, for instance.[224] This means that controllers in some situations may be able to achieve the minimum bleed rate identified in EPA's TSD of 0.2 scfh, while some other classes of controllers may hover closer to the 5 scfh upper limit. Although *no* "low-bleed devices on the market today" has emissions of 6 scfh, according to EPA's analysis, this functional variation means that EPA must set standards by class of control device.

EPA must therefore define a maximum bleed rate for each functional class of pneumatic controller, setting each bleed rate to force technological improvements, consistent with the goals of the NSPS program. This range of allowable bleed rates must, of course, extend no higher than 5 scfh, the highest bleed rate supported in the record. For each class of controller, EPA must fully justify that its standard is no higher than the lowest emission rates that each class of controller can achieve.

Finally, we understand that some purported low-bleed pneumatics may not perform as advertised under all circumstances, or if poorly maintained. This heightens the importance of including rigorous leak detection and monitoring standards in the final rule in order to ensure that EPA captures the full benefits of its proposal.

d. Extend Control Standards to All Pneumatic Devices

EPA uses both the terms pneumatic "device" and pneumatic "controller" in the preamble, but the control standards apply only to pneumatic controllers.[225] This is a serious oversight, which EPA must correct, because the category of well-field pneumatics devices is broader than "controllers," and includes snap-acting devices, chemical injection pumps, and other devices.

In particular, pneumatic *pumps* are a significant emissions source, and those emissions can be controlled. Wyoming, for instance, requires that such pumps achieve a 98% control efficiency, or route all their emissions into closed loop systems.[226] Thus, controls which can achieve this level of reduction are not only available, but are actually in use. EPA must require them here.

In fact, EPA appears to have considered doing so, as a definition of "pneumatic pump" remains in Proposed 40 C.F.R. § 60.5430. EPA must now follow through and control this

[224] 76 Fed. Reg. at 52,761.
[225] *See* Copeland & Williams Report at 37-38.
[226] *See id.* at 37 n. 141 (citing See Wyoming Department of Environmental Quality, Air Quality Division, Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, Revised March 2010 ("Wy. Guidance") at 9, 19.

emissions source or, at a minimum, provide a legally sufficient rationale as to why it will not do so.

Above we assert that EPA must base the standard on "zero-bleed" pneumatic *controllers* unless operators demonstrate that electricity is not feasibly available on site. In general EPA's standards should require that these other pneumatic *devices* be converted to "zero-bleed" (instrument air, electrical actuation, mechanical actuation, etc.) in conjunction with requirements for zero-bleed pneumatic controllers.

C. Compressors

1. EPA's Proposal

EPA proposes to treat each centrifugal or reciprocating compressor located between the wellhead and the city gate, except those located at the well site, as an affected facility.[227] EPA determined, for both reciprocating and centrifugal compressors, that fugitive emissions from these sources cannot be reliably measured or controlled. It therefore set a design and work practice standard under section 111(h) for these sources (and hence is bound by that section's BTSER standard, as we discuss above).[228]

EPA estimates that new centrifugal compressors at processing and transmission and storage sites, if uncontrolled, will annually emit 5,408 tons of methane, 377.9 tons of VOCs, and 13.25 tons of HAPs; non-wellhead reciprocating compressors will annually emit 8,100 tons of methane, 2,090.73 tons of VOCs, and 78.63 tons of HAPs.[229] Clearly, these emissions are significant.

Under the proposed NSPS, all new or modified centrifugal compressors must use a dry seal system upon initial startup.[230] New or modified reciprocating compressors must replace rod packing before the unit reaches 26,000 hours of operation, and units must continuously monitor hours of operation to ensure compliance with this standard.[231]

2. BTSER Determination

We generally agree that among centrifugal compressors, use of dry seals as opposed to wet seals is BTSER. Dry seals are a better option than the option to use "wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device" because of the adverse collateral impacts of flares.[232] We further

[227] 76 Fed. Reg. at 52,799. (Proposed 40 C.F.R. § 60.5365(b)-(c)).
[228] *See* 76 Fed. Reg. at 52,762-63 (explaining these determinations); 42 U.S.C. § 111(h) (providing for such standards).
[229] TSD at 6-10.
[230] 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5380(a)).
[231] *Id.*. at 52,800. (Proposed 40 C.F.R. § 60.5385(a)).
[232] *Id.* at 52,746.

agree that among reciprocating compressors, frequent rod packing replacement is BTSER.

We also agree that each compressor is properly considered an affected "facility," subject to EPA's proposed standards. As we explained above, each compressor is plainly an "apparatus" properly regulated under section 111, and installation of a new replacement compressor is construction subject to the NSPS because the regulations define "construction" as "fabrication, erection or installation of an affected facility."[233]

As we explain below, however, we disagree with EPA's treatment of the two compressor technologies as inherently distinct. EPA must investigate whether dry seal centrifugal compressors represent BTSER for compressors generally. If dry seal centrifugal compressors are determined to have the lowest emissions, then EPA must use that emission rate as its "achievable" emission limitation standard. Indeed, because EPA is setting "design, equipment, work practice, or operational standards,"[234] it should be able simply to require centrifugal compressors as a design standard for new installations, such that new installations of reciprocating compressors would be prohibited by the NSPS. In this event, EPA must nonetheless also promulgate a rod-packing standard, which must apply to existing reciprocating compressors that are "modified" under CAA § 111(a).

We also disagree, in several regards, with how EPA has proposed to implement its requirements. As occurs throughout the proposal, EPA has allowed for improperly broad exemptions, and impermissibly high emissions rates. It must correct these errors in order to promulgate legal final standards.

***3. Critique*s**

a. Centrifugal Compressors

Although we support the use of dry seals as BSER, EPA must specifically require the use of "tandem" or double dry seal systems.[235]

As EPA has explained, wet seals may leak between 40-200 scf per minute (scfm), while dry seals can reduce emissions to 6 scfm or below (some EPA estimates put such leaks at just 0.5-3 scfm).[236] These replacements can pay for themselves in as little as 11 months,

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[233] 40 C.F.R. § 60.2 (2010).
[234] 42 U.S.C. § 7411(h)(1).
[235] Copeland and Williams 30-32.
[236] EPA Natural Gas STAR, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors,* attached hereto as Exhibit 86; *see also* EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 12 (showing low emissions from dry seals and concluding that such seals "often used in tandem" are profitable to install in many circumstances), attached hereto as Exhibit 87.

according to EPA, and can then generate hundreds of thousands of dollars in savings annually.[237] Dry seals are readily available, and are used throughout the industry.[238]

All dry seals are not equivalent, however. Tandem seals substantially improve emissions control. According to EPA, such seals are "very effective in reducing gas leakage," as "[t]his type of seal has less than one percent of the leakage of a wet seal system vented in to the atmosphere and costs considerably less to operate."[239] Indeed, according to one prominent vendor, tandem dry seals are now "[t]he most popular configuration used in the industry."[240]

Nonetheless, EPA's proposal does not specify the use of tandem dry seals, or, indeed, even provide a definition of the "dry seal system" that EPA requires.[241] EPA must correct this error. EPA needs to require all centrifugal compressor sources to use *tandem* dry seals, and to clearly define "dry seal system" accordingly.

b. Reciprocating Compressors

For new facilities, EPA must investigate whether the NSPS should require the use of centrifugal compressors instead of reciprocating compressors as BTSER.

As a threshold issue, EPA must more thoroughly examine reciprocating compressor emissions. The data EPA has provided, however, permits the following extrapolation. EPA's posits that the average reciprocal compressor with newly installed but worn-in rod packing will leak 11.5 scfh per cylinder.[242] Other sources have indicated that reciprocating compressors with newly installed rod packing can leak as much as 60 scfh, apparently from a single cylinder.[243] EPA has also stated that a compressor with worn rod packing may leak 900 scfh from a single cylinder.[244] Although EPA did not specifically explain how much use led to this level of wear, EPA has also stated that "conventional bronze-metallic packing rings wear out and need to be replaced every 3

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[237] *See id.* at 1.

[238] *See, e.g.*, Dresser-Rand, *Dry Gas Seals* (vendor offering seals and noting that "[b]ecause of their advantages, dry gas seals are now installed on 95% of new compressors for varied service throughout the world"), attached hereto as Exhibit 88; Trem Engineering, *Mechanical Seals and Dry Gas Seals for Oil and Gas* (2010) (vendor offering dry seals and tandem dry seals), attached hereto as Exhibit 89; Globalspec, *Dry Gas Seal Configuration* (explaining how "state-of-the-art tandem gas seal designs" have become popular), attached hereto as Exhibit 90; Rolls-Royce, *Centrifugal Compressors* (describing availability of tandem dry seals in Rolls Royce designs), attached hereto as Exhibit 91.

[239] *Id.* at 4.

[240] Kaydon Ring & Seal Inc., *Dry Gas Seals* at 2. attached hereto as Exhibit 92.

[241] *See* 76 Fed. Reg. at 52,800. Proposed 40 C.F.R. § 60.5380.

[242] Copeland and Williams at 24 n.96 (citing TSD 6-12 to 6-14).

[243] Sahu Report at 20 n.80 (citing Reducing Emissions from Compressor Seals, Lessons Learned from Natural Gas Star, September 22, 2004. Available at www.epa.gov/gasstar).

[244] Natural Gas Star (2006), "Reducing Methane Emissions from Compressor Rod Packing Systems" Available at http://www.epa.gov/gasstar/tools/recommended.html, attached hereto as Exhibit 93.

to 5 years, depending on the compressor's rate of usage."[245] Absent further detail, we assume that 900 scfh represents the leak rate of a reciprocating compressor cylinder at the end of this 3 to 5 year lifecycle.[246] We further assume, for purposes of this comment, that rod packing emissions increase linearly across their lifespan, absent specific information about the trajectory of emissions. Based on these figures and assumptions, we estimate that a reciprocating compressor cylinder emits an average of 456 scfh across its lifespan when rod packing is replaced after three years of operating time.[247] Each compressor has an average of 2.5 – 4.5 cylinders,[248] so a conservative estimate is that an average compressor emits about 1,500 scfh.

This estimate suggests that centrifugal compressors equipped with dry seals (even a single dry seal) have fewer emissions than even well maintained reciprocating compressors.[249] As explained in Dr. Sahu's report, dry seal centrifugal compressors are observed to emit the equivalent of 30 to 180 scfh, while reciprocating compressors, again, may be emitting 1,500 scfh or more. *Id.* Furthermore, data from the US Greenhouse Inventory shows that the average centrifugal compressor is many times larger (higher horsepower) than the average reciprocal compressor.[250] As a result the comparison above underestimates the lower emissions of centrifugal compressors. Accordingly, BTSER-level emissions are set by the centrifugal compressors. Therefore, as EPA sets equipment standards for this industry, it must require the use of centrifugal compressors instead of reciprocating compressors wherever such use will not impose unbearable costs on industry.[251]

If EPA does not take this course, it must strengthen the rod packing standard for reciprocating compressors. As noted, wear and tear on rod packing assemblages can increase emissions from 12 scfh to 900 scfh. EPA proposes to require replacement before 26,000 hours of use, the equivalent of three years of continuous usage. EPA should have evaluated a more aggressive rod packing replacement schedule. A more aggressive schedule might result in further cost *savings* to operators by avoiding methane losses. For example a "120 scfh leak reduction rate would require roughly 2 years payback assuming a gas cost of $7/Mcf, a 10% interest rate and 8,000 hours of operation."[252] Of course, the BTSER standard must go beyond only requiring those emission reductions that are actually profitable to the operator. The above merely

[245] 76 Fed. Reg. at 52,762.
[246] Sahu Report at 26.
[247] *Id.*
[248] TSD at table 6-2, page 6-4.
[249] Sahu Report at 20.
[250] Comparison based on emissions factors and activity data in tables A-121 and A-122, pp. A-153 – A-154, *US Greenhouse Gas Inventory*.
[251] As we later discuss, a rod-repacking standard should, however, be retained for existing reciprocating compressors if and when EPA regulates those facilities.
[252] Copeland and Williams Report at 30 n.125, *see also* Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", p. 8 (October 2006) http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

demonstrates that EPA must investigate whether to shorten the 26,000-hour replacement schedule.

We also ask that EPA consider whether a leak-detection based emissions regime, requiring replacement when emissions cross a certain threshold, constitutes BSER. Because rod packing replacement quickly pays for itself in many scenarios, such a threshold could be low. Some compressors may begin to leak significantly long before the 26,000 hour operation time, but EPA's time-based replacement standard will not address these leaks. If such early failures are at all common, EPA's proposal will unnecessarily allow excess emissions, and so will not constitute BSER. EPA must evaluate this possibility, and, if it declines to adopt a leak-based threshold, must explain why it does not do so.

Beyond rod packing replacement, EPA must evaluate requiring installation of advanced rod packing materials.[253,254]

c. Scope of the Standard

EPA must revisit its decision to exclude wellhead compressors from the NSPS. Wellhead compressors represent a significant fraction of the number of compressors; for example, EPA's figures indicate that 13% of all emissions from new reciprocating compressors are predicted to come from reciprocating compressors at wellheads.[255] With the rapid growth in gas production in recent years, this fraction will grow.

EPA excluded reciprocating wellhead compressors from the standard on the basis of the low VOC emissions from these compressors.[256] EPA has not explained how it determined the level of these emissions. It must do so. EPA appears to have relied, in part, on the conclusion that wellhead compressors are typically "small."[257] A compressor engine survey conducted in Texas states the following: "Some of the findings of this . . . study include: 1. Generally, less than 1% of the well-head engine capacity is comprised by engines smaller that 50 hp; and 2. Generally, 50 to 73% of the well-head engine capacity is comprised by engines greater than 500 hp, depending on

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[253] Copeland and Williams, 30.

[254] Rod repacking materials are readily available. *See, e.g.*, EPA, *Methane Savings from Compressors and VRUs* (July 27, 2006) at 5-6 (quantifying emissions reductions and cost savings from rod repacking); EPA, *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems* at 3 (concluding that "[m]onitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions to the atmosphere and save money"); CECO, *Reduce Gas Emissions: Install CECO Low Emission Packing* (vendor offering rod repacking); CECO, *Low Emission Packing* (2010) (same), attached hereto as Exhibit 94.

[255] Copeland and Williams at 26-39.

[256] 76 Fed. Reg. at 52,762.

[257] *Id.*

the region."[258] We do not consider engines greater than 500 hp as "small." Thus, EPA's assertion regarding the size of the typical wellhead compressor appears unwarranted. We are similarly unable to verify EPA's calculations of the emission rate for wellhead reciprocating compressors (estimated by EPA as 0.044 tpy VOC) or the cost per ton of reducing these emissions (estimated at $84,000).[259] Thus, although EPA purports to distinguish wellhead reciprocating compressors from other reciprocating compressors, this distinction is unsupported, and unreasonable. If EPA wishes to retain the exemption, it must justify it on the record.

EPA has provided no explanation whatsoever regarding its decision to exclude wellhead *centrifugal* compressors from the standard.[260] It must do so. In the absence of a compelling rationale to the contrary, wellhead compressors (of both varieties) must be subject to the same standards as other compressors in the production sector. While EPA does not report methane emissions from wellhead centrifugal compressors in its Greenhouse Gas inventories, implying that there were few or zero centrifugal compressors at wellheads when the basic research behind the inventory was carried out some time ago, this may no longer be true. In any case centrifugal compressors may be installed at wellheads in the future.

d. Compressor Exhaust

EPA has also failed to set a standard for emissions from compressor exhaust. Exhaust from reciprocating internal combustion engines (RICE) and turbines which drive natural gas compressors is a very significant source of methane emissions. In 2009, compressor exhaust accounted for 552,000 metric tons of methane emissions, or 4.6% of the total methane emissions from the oil and gas sector.[261]

While exhaust from some new compressor engines and turbines is addressed under existing standards such as 40 CFR Part 60 Subparts JJJJ and KKKK, according to EPA, these standards do not address methane. EPA offered no evidence that the emissions controls that those standards do require effectively reduce methane. Methane is less reactive than many hydrocarbons[262] and may escape destruction via catalytic oxidation, demonstrating that these other existing standards may be inadequate. Below, we discuss, at length, EPA's obligation to control methane as a pollutant from this sector.

[258] Houston Advanced Research Center, *Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities, H68 Final Report* (October 2006) pp. 3, attached hereto as Exhibit 95.
[259] 76 Fed. Reg. at 52,762, Sahu at 20-24.
[260] *See* 76 Fed. Reg. at 52,761.
[261] US EPA (2011), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, tables A-120 – A-123 (pp. A-149 – A-155). Figures include scaling for emissions reductions reported to Natural Gas STAR.
[262] Sander, S. P., J. Abbatt, J. R. Barker, J. B. Burkholder, R. R. Friedl, D. M. Golden, R. E. Huie, C. E. Kolb, M. J. Kurylo, G. K. Moortgat, V. L. Orkin and P. H. Wine (2011), "Chemical Kinetics and Photochemical Data for Use in Atmospheric Studies, Evaluation No. 17," JPL Publication 10-6, Jet Propulsion Laboratory, Pasadena. http://jpldataeval.jpl.nasa.gov, attached hereto as Exhibit 96.

Compressor exhaust provides a clear instance where such controls are necessary, and EPA must, therefore, regulate methane from compressor exhaust.

According to emissions factors in the US Greenhouse Gas Inventory, turbines produce less methane (per horsepower-hour) than RICE engines by about a factor of 25.[263] Above, we demonstrate that because centrifugal compressors leak less than reciprocating compressors, centrifugal compressors are the BTSER for VOC emissions from certain compressors. Centrifugal compressors are powered by turbines, unlike reciprocating compressors that are driven by RICE (either can alternatively be powered by electric motors, with zero emissions). Therefore, requiring centrifugal compressors as BTSER will have a substantial co-benefit for methane reductions in the engine/turbine exhaust. A requirement for compressors to be driven by turbines (or electric motors where electricity is available) would therefore be a logical compliment to the centrifugal compressor requirement.

EPA has previously recognized that this is a cost-effective methane abatement option.[264] It must impose standards to control compressor exhaust here.

D. Storage Vessels

1. EPA's Proposal

Because EPA has also proposed (substantively identical) storage vessel standards for new and existing vessels under its proposed NESHAP, the proposed NSPS covers only new and modified vessels not addressed by the NESHAP.[265]

The NSPS standard applies to storage vessels, defined as:

> a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 [tons per year].[266]

Under that standard, storage vessels would essentially have to comply with the NESHAP standard (which is incorporated into the NSPS). That standard requires vessels to be equipped with a cover and closed-vent system, or control device, that channels all

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[263] See emissions factors list in US EPA (2011), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, tables A-120 – A-122 (pp. A-149 – A-154).
[264] US EPA (2003), *International Analysis of Methane and Nitrous Oxide Abatement Opportunities: Report to Energy Modeling Forum, Working Group 21*, Appendix B, available at http://www.epa.gov/methane/appendices.html, attached hereto as Exhibit 97.
[265] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(b)). *See also id.* at 52,769 (proposing to expand the existing NESHAP to cover all storage vessels, not just those with the potential for flash emissions).
[266] *Id.* at 52,810 (Proposed 40 C.F.R. § 60.5430).

emissions to either a combustion device (or flare) or vapor recovery unit ("VRU") with at least 95% control efficiency by weight.[267]

2. BSER Determination

EPA estimates that uncontrolled VOC emissions from storage vessels, in the absence of the NSPS, would be 21,373 tons per year for condensate storage and 23,421 tons per year for crude oil storage.[268] Vapor recovery units, or combustion devices with 95% control efficiency, can reduce VOC emissions by 29,654 tons per year (in 2015).[269]

Assuming, as EPA does, that half of facilities use combustion devices and half use VRUs, EPA's proposed rule would achieve significant VOC reductions at just $143/ton (accounting for additional revenues from recovered condensate).[270]

This is an eminently reasonable control cost, and is reflected in the wide use of vessel emissions control measures throughout the industry. As the Copeland and Williams Report discusses, similar (and more rigorous) control technologies are already in wide use, including in Wyoming, where a 98% control efficiency is required.[271]

EPA Natural Gas STAR documents also support these emissions controls. EPA partners report significant emissions reductions and financial gains. Chevron USA Production Company, for instance, installed VRUs on eight crude oil storage tanks and recovered over $1.2 million in savings, while reducing methane emissions by 21,900 Mcf per year from each unit. The project paid for itself in three months.[272]

We therefore agree with EPA that some combination of combustion devices and VRU on storage tanks, at am minimum, constitutes BSER for this class of facilities. As we discuss below, however, the statute requires EPA to look further, toward emerging control options and improperly excluded sources, in order to set legal emissions standards for this part of the industry..

3. Critiques

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[267] *Id.* at 52,815-16 (Proposed 40 C.F.R. §§ 63.766, 63.771).
[268] TSD at 7-12.
[269] RIA at 3-17.
[270] As we discuss below, it seems likely that combustion devices will be used more frequently than VRUs. This will somewhat raise control costs (though they will remain eminently reasonable). Below, we urge EPA to work to reduce the use of flares, as they produce additional air pollution, while VRUs do not.
[271] Copeland and Williams Report at 54. *See also* Wy. Guidance at 5, 11, 18 (requiring such controls).
[272] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 10, available at: http://www.epa.gov/gasstar/documents/ll_final_vap.pdf, attached hereto as Exhibit 98.

Field data and state regulations demonstrate that EPA must raise control efficiency requirements, and minimize flaring, in order to ensure that the proposed standards reflect BSER. In addition, EPA must limit exemptions to these standards and cover all storage vessels and similar impoundments, pits, sumps, and well cellars, including those that contain produced water. EPA must also revise the regulatory text to eliminate confusing cross references which may impede compliance and enforcement efforts.

a. Tighten Emission Control Requirements

EPA must raise its control efficiency requirements and limit, or eliminate, the use of combustion devices.

Initially, EPA provides only limited support for the proposition that a 95% control efficiency constitutes what may be "fairly projected for the regulated future."[273] On the contrary, EPA's own Natural Gas STAR documents report that VRUs can "recover *over* 95 percent of the hydrocarbon emissions that accumulate in storage tanks."[274] A 98% control efficiency is, again, achievable, and is required in Wyoming.[275] Because these controls are widely-used, their level of control is plainly "[a]n achievable standard."[276] EPA's proposal thus falls below BSER, and must be strengthened.[277]

We are also unpersuaded that EPA has achieved the right balance between VRUs and flares, in light of the serious adverse environmental impacts of flaring. As EPA explains:

> A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well . . . . A VRU also does not have secondary air impacts that flaring does . . . .[278]

These flaring impacts include NO_x, SO_2, and PM emissions, as well as emissions of other pollutants.[279] EPA must avoid these impacts wherever feasible.

We recognize that EPA determined it could not simply select VRUs as reflecting BSER for storage vessels because "a VRU cannot be used in all instances."[280] But that is not the statutory standard for new source emissions under 111(b). EPA must ensure that VRU-

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[273] *Lignite Energy Council*, 198 F.3d at 934.
[274] EPA Natural Gas STAR, *Lessons Learned from Natural Gas STAR Partners: Installing Vapor Recovery Units on Crude Oil Storage Tanks* (2006) at 1.
[275] *See* Wy Guidance at 5, 11, 18 (requiring such controls).
[276] *See Essex Chem. Corp.*, 486 F.2d at 433.
[277] *See also* Copeland and Williams Report at 50 (describing these higher control efficiencies).
[278] 76 Fed. Reg. at 52,763.
[279] *See id.*; *see also* TSD at 7-17 (listing flaring emissions, including THC, CO, CO_2, NOx, SO_2, and PM).
[280] 76 Fed. Reg. at 52,763.

level control efficiencies are achieved in all applications so long as that does not impose exorbitant costs on industry (EPA now predicts that only 50% of new sources will use VRUs, while the remainder will flare.)[281] It must do so by requiring all affected sources to achieve control efficiencies of 98%, with no secondary emissions of NO_x, except where the operator can demonstrate to EPA that it cannot install a VRU. In that case (and only that case) EPA could allow a 95% control efficiency (which can be met either by VRU or flare), with that exemption subject to review or challenge. Such an approach is structurally similar to EPA's efforts to construct an exemption from its "low-bleed" standard for controllers,[282] and would similarly hold operators to a higher standard, with limited exemptions. EPA must adopt it.

b. Limit Exemptions

EPA proposes to exempt "small throughput" storage vessels – that is, vessels with either an average condensate throughput of less than 1 barrel per day per vessel or average oil throughput of less than 20 barrels per day per vessel.[283] These throughput rates translate into a 6.1 ton per year per tank VOC emission rate for condensate tanks and a 5.8 ton per year per tank VOC emission rate for crude oil tanks.[284] This exemption is not lawful.

Initially, EPA's own calculations show that the annualized cost of installing a VRU is $18,983 and $8,909 for a flare – translating into control efficiencies of about $3,000 per ton of VOC emissions reduced for a VRU (depending on the tonnage of emissions captured).[285] These are not exorbitant costs – certainly far less than the greatest that "the industry could bear and survive."[286] In exchange for these costs, EPA would significantly reduce VOCs at these facilities – by 5.77 tons per year per tank for condensate tanks and 1.4 tons per year per tank for crude oil tanks.[287] These are substantial emissions reductions at fairly low costs. EPA must, therefore, either abandon or strictly limit the exemption.

If the exemption is limited, however, rather than abandoned, it must be revised in several respects:

First, in order to avoid exempting substantial cumulative emissions from tank farms that contain numerous tanks which may fall below EPA's applicability threshold, EPA must structure its exemption (whatever the thresholds) to apply to tank batteries, rather than

[281] TSD at 7-24
[282] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5390(a))
[283] *Id.* at 52,800 (Proposed 40 C.F.R. § 60.5395(a)(1)-(2)).
[284] TSD at 7-19, 7-21.
[285] These projected costs are likely too high. *See infra* Section VII(B)(2)(f).
[286] *See Portland Cement II*, 513 F.2d at 508.
[287] *See* TSD at 7-19, 7-21.

to individual tanks.[288] This may be what EPA intended the current proposal to accomplish, because its proposed storage vessel definition includes a "series of stationary vessels that are either manifolded together or are located at a single well site."[289] This intent is not clear from the preamble, however. EPA must therefore either confirm that its standards (and exemptions) are intended to apply to vessels both individually and cumulatively, or must revise them accordingly.

Second, EPA must, at a minimum, limit the exemption to truly small tanks with truly small emissions. Because the public experiences adverse impacts from *emissions*, rather than throughput, EPA must base its exemption on emissions thresholds. These thresholds must be set at the lowest reasonable point, which is below the current thresholds.

Specifically, for condensate storage vessels, a 3 ton/year emissions rate would reach 1,782 tanks, reducing each tank's emissions by 95%, at a cost of only $6,576 per ton of VOC. For crude oil tanks, a 1.5 ton/year emissions cut-off would trigger 95% emissions reductions at 825 tanks for $13,686/ton. These costs are clearly reasonable, and will produce substantially greater benefits than those flowing from the thresholds that EPA proposes to use. We therefore assert that EPA must limit its exemption to tanks with these lower emissions rates.

We further note in this regard that EPA's cut-off in proposed 40 C.F.R. § 60.5395 appears to be in tension with its underlying storage vessel definition. That definition defines storage vessels as including only those tanks that "have potential for VOC emissions equal to or greater than 10 tpy."[290] But even using EPA's proposed thresholds, the smallest emissions rate tanks covered by the standards would have emissions of 6.1 tons per year (condensate) and 5.8 tons per year (crude oil).[291] EPA presumably does not intend to exempt tanks with these emissions from all control just because their emissions are below 10 tons per year of VOC. EPA must therefore delete the "10 tpy" language from its definition section, as it conflicts with the lower emissions threshold it sets in the substantive storage vessel standard itself.

Third, EPA should further condition its exemption by limiting it to only small throughput tanks with low vapor pressure. Such an exemption would ensure that only tanks which do not contain significantly volatile substances are exempt.

Such vapor pressure limitations are used in certain California air quality districts. The Santa Barbara County Air Pollution Control District, for instance, exempts tanks whose vapor pressure is below 0.5 lb/sq. in,[292] and the Ventura County Air Pollution Control

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[288] *See* Sahu Report at 24-25.
[289] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[290] 76 Fed. Reg. at 52,810 (Proposed 40 C.F.R. § 60.5430).
[291] TSD at 7-19, 7-21.
[292] SBAPCD Rule 325(B)(1)(a), attached hereto as Exhibit 99.

District takes a similar approach (using VOC content rather than vapor pressure), and exempts tanks with a VOC concentration of 5 mg/L of water or below.[293] EPA must follow suit and condition its exemption similarly.

c. Address Additional VOC Sources Arising from Liquid Storage

Storage vessels are not the only liquid storage systems that emit VOCs. Well cellars, sumps, and even pools of oil can and do emit substantial VOCs, which are controlled by several different state regulators. EPA must include standards for such sources based upon these available controls.

Examples of such controls are plentiful, especially among the California air districts. In particular:

- The South Coast Air Quality Management District prohibits well cellars with a total organic compound concentration of greater than 500 ppm,[294] bars organic liquid storage in well cellars, and requires regular monitoring,[295] Since 2006, no well cellar may vent any natural gas to the atmosphere.[296]

- The Santa Barbara County Air Pollution Control District requires regular pumping of well cellars.[297] It also bars all "primary sumps" – that is, any sump that receives oil and produced water directly from field gathering or production systems – and requires that all pits and post-primary sumps (which receive their liquids after separation processes) be replaced with tanks or covered, with a vapor recovery unit.[298]

- The Ventura County Air Pollution Control District likewise bars "first stage production sumps" and requires all other sumps, pits, and pounds to be covered.[299]

- The San Joaquin Valley Air Pollution Control District requires all sumps to be covered with a material impervious to VOCs.[300]

- The Bay Area Air Quality Management District bars all "open liquid pools of crude oil or condensate" and all uncovered vessels larger than 250 ml; it also requires that all well cellars be covered.[301]

[293] VCAPCD Rule 71.4(C)(1)(c), attached hereto as Exhibit 100.
[294] SCAMD Rule 1148.1(d)(1), attached hereto as Exhibit 112
[295] Rule 1148.1(d)(2)-(3).
[296] Rule 1148.1(d)(6).
[297] SBCAPCD Rule 344(D)(3), attached hereto as Exhibit 113
[298] Rule 344(D)(1)-(2).
[299] VCAPCD Rule 71.4(B)
[300] SJVAPCD Rule 4402(5), attached hereto as Exhibit 114

EPA neither discusses these precedents, nor acknowledges the existence of VOCs from sumps, pools, and well cellars. As a result, it has unreasonably left these sources unregulated.

In the final rule, EPA must include standards for each liquid storage source, including, but not limited to, sumps, pools, pits, pounds, and well cellars, or provide a legally-supportable rationale as to why it will not follow the (decades-old) control precedent set by the California air quality control districts.

d. Address Produced Water

Produced water storage (including ponds and tanks) constitutes an important subset of the liquid storage systems we discuss above. Produced water is a significant VOC source, and EPA must control it properly.

First, at an absolute minimum, EPA must make clear that its proposed standards apply to produced water tanks. Wyoming already requires new produced water *tanks* to achieve the same 98% emissions control that it requires of crude oil and condensate tanks.[302] The Santa Barbara County Air Pollution Control District likewise requires produced water tanks to be controlled to a 90% efficiency.[303] These examples demonstrate that controls are plainly available and effective, but EPA has not included produced water tanks in its storage vessel definition. It must do so.

Second, EPA needs to develop controls for produced water ponds and sumps, holding these sources to a similarly rigorous control efficiency standard.

EPA "believes that produced water ponds are . . . a potentially significant source of emissions," and is seeking comment on control options for these ponds.[304] We agree that produced water can produce significant VOC emissions. Some reports do establish that these ponds emit harmful pollution. EPA research has shown that produced water ponds used by the oil and gas industries can emit VOCs including the hazardous pollutants benzene, toluene, xylenes, and methanol.[305] New York State has also gathered data on emissions from impoundments, and concluded that these impoundments could be significant sources of the hazardous air pollutant methanol:

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[301] BAAQMD Rules 8-37-302 & 8-37-303, attached hereto as Exhibit 115
[302] Wy Guidance at 16, 20.
[303] *See* SBCAPCD Rules 344(D)(2)(a); 325(D).
[304] 76 Fed. Reg. at 52,756.
[305] Thoma, E. (2009) *Measurement of Emissions from Produced Water Ponds: Upstream Oil and Gas Study #1. Final Report.* EPA Report EPA/600/R-09/132. Available at http://www.epa.gov/nrmrl/pubs/600r09132/600r09132.pdf, attached hereto as Exhibit 101.

> Analysis of air emission rates of some of the compounds used in the fracturing fluids in the Marcellus Shale reveals potential for emissions of hazardous air pollutants (HAPs), in particular methanol, from the recovered (flowback) water stored in central impoundments. This methanol is present as a major component of the surfactants, cross-linker solutions, scale inhibitors and iron control solutions used as additives in the frac water. Current field experience indicates that an approximately 25% recovery of fracturing water from Marcellus shale wells may be expected. Thus, using a 25% recovery factor of a nominal 5,000,000 gallons of frac water used for each well, an estimated 6,500 pounds (3.25 tons) of methanol will be contained in the flow- back water. Since methanol has a relatively high vapor pressure, its release to the atmosphere could possibly occur within only about two days after the recovered water is transferred to the impoundment. Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission of 32.5 tons (i.e., "major" quantity of HAP) is theoretically possible at a central impoundment.[306]

Because VOCs and hazardous air pollutants are likely co-emitted from these sources, they appear to be potentially significant emissions sources, warranting coverage by these standards.

Pit emissions can be estimated using EPA's own test methods. The Ventura County Air Pollution Control District uses EPA Method 8015, which requires sampling of only a small portion of the pit surface.[307]

As we discuss above, California air districts in areas with oil and gas production have long controlled emissions from produced water ponds, by, for instance, requiring such ponds to be covered, or that their emissions be captured or flared, or simply by requiring ponds to be replaced by tanks.[308] These standards are described in the section above, on liquid storage.

The Santa Barbara County Air Pollution Control District, the Ventura County Air Pollution Control District, and the Bay Area Air Quality Management District, in particular, have all banned at least certain forms of open liquid storage (such as "primary sumps"), ordering that they be replaced with well-controlled tanks (equipped with appropriate

[306] *Draft New York Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program* (Sept. 30, 2009) at section 6.5.1.8, attached hereto as Exhibit 102. New York's recent revised impact statement (Sept. 2011) does not contain this statement, but only because "[t]he Department was informed in September 2010 that operators would not routinely propose to store flowback water either in reserve pits on the wellpad or in centralized impoundments" and therefore did not address "these practices" in the revised document. *See* Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (September 2011) at section 1.1.1.1, attached hereto as Exhibit 103.
[307] VCAPCD Rule 71.4(F).
[308] See VCAPCD Rule 71.4 & SBCAPCD Rule 325.

flares or VRUs). Tanks are inherently more readily managed then pits, so the lowest-possible emissions rate from a tank constitutes BSER.

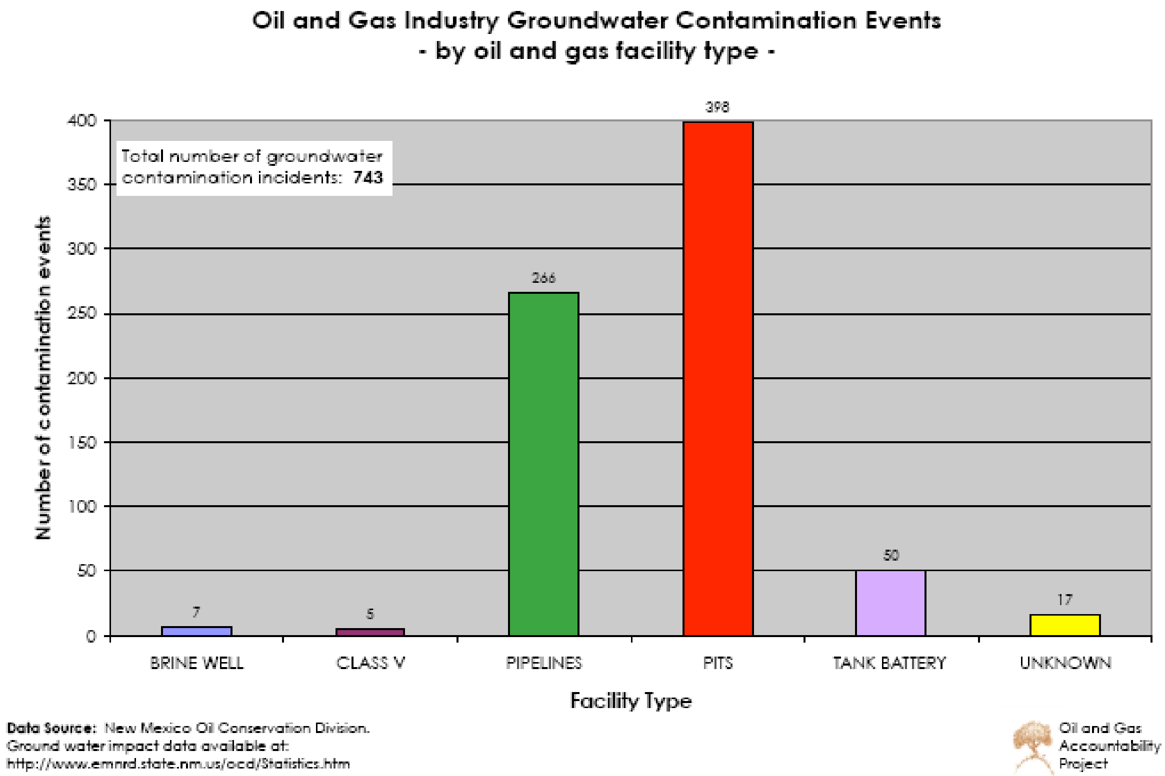
Because this technology is available, and in use, it plainly constitutes BSER for liquids storage. EPA must therefore set emissions standards for produced water based upon the emissions rate from well-controlled tanks. (And, to the extent it determines that some classes of produced water storage cannot be managed in tanks, EPA must continue to follow the path blazed by the California air districts, and set BSER standards based, at a minimum, upon *covered* and well-controlled impoundments).

Such a standard also would produce significant "non-air quality health and environmental" benefits, especially to the extent that operators opted to avoid using pits, in lieu of tanks, and because covers help prevent spills and falls into pits. Surface spills and leaks from waste pits pollute water across the country, so eliminating these pits would greatly reduce water pollution issues associated with oil and gas extraction. The open pits and ponds also pose a significant risk to livestock and to wildlife, such as birds that alight on them and small animals that use them for drinking water.

For instance, New Mexico data, summarized by the Oil and Gas Accountability Project, show 743 instances of ground water contamination, almost all of it occurring over the last three decades. 398 of those incidents – over half – are linked to faulty pits.[309]

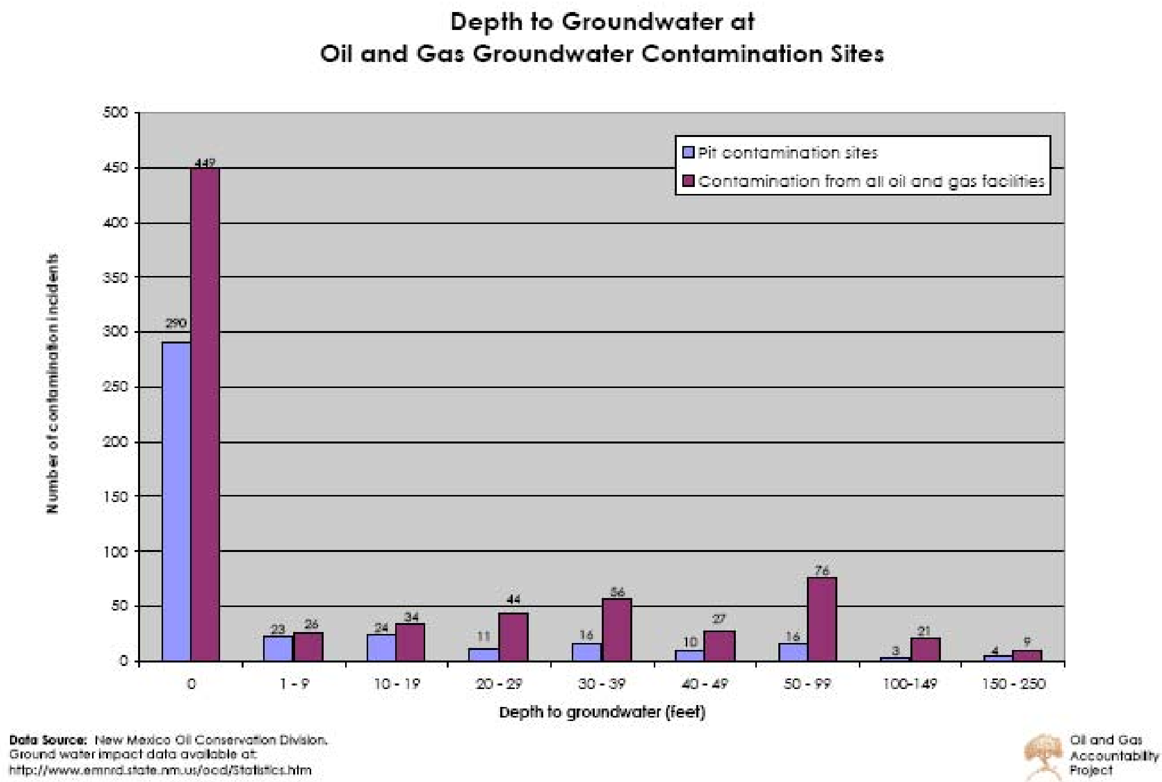
Figure 3

[309] OGAP Analysis of data provided in New Mexico Energy, Minerals and Natural Resources Dep't, Oil and Conservation Div., *Cases Where Pit Substances Contaminated New Mexico's Ground Water* (2008). OGAP Analysis and raw data available at http://www.earthworksaction.org/NM_GW_Contamination.cfm, attached hereto as Exhibit 104.



The bulk of pit contamination is associated with shallow groundwater, of the sort which can readily flow into drinking water wells, as the New Mexico data demonstrate:

Figure 4



Similar incidents are occurring across the country. [310] In Pennsylvania, for instance, state authorities were forced to quarantine cattle after a pit leaked into their field, collecting in a smelly pool that killed the grass.[311] In Colorado, leaky pits with torn liners spilled more than 6,000 barrels of waste,[312] and one leaking pit contaminated drinking water with benzene. In state after state, poorly-regulated and inspected pits are imperiling the public.

Thus, EPA rules requiring produced water to be sequestered in tanks, or, at a minimum, discouraging the use of uncovered pits by setting rigorous emission control standards, would not only control VOCs, but also make important progress on controlling water pollution from these sources.

To the extent that EPA needs additional data to support such a requirement, e.g., data on emissions from pits, available controls for achieving substantial emission control

[310] *See generally*, Natural Resources Defense Council, Petition for Rulemaking to Regulate Oil and Gas Waste (Sept. 8, 2010) (collecting these incidents), attached hereto as Exhibit 105.
[311] Pro Publica, Nicolas Kusnetz, *A Fracking First in Pennsylvania: Cattle Quarantine* (July 2, 2010), available at http://www.propublica.org/article/a-fracking-first-in-pennsylvania-cattle-quarantine, attached hereto as Exhibit 106.
[312] *See* Colorado Oil and Gas Conservation Commission, Inspection/Incident Inquiry, Spill Reports Doc. Nos. 1630424, 1630436, 1630427, 1630428, 1630429, 1630430, all attached hereto as Exhibit 107.

from pits, and/or costs of converting from pits to tanks, it must specifically request such information from companies under section 114.

e. Textual Issues

Finally, EPA must revise the rule text to avoid cross-references to its NESHAP standard. At present, the proposed rule simply cites to the NESHAP for its emission standards,[313] but this cross-citation is confusing, as the cited sections – and the sections that they, in turn, cite – are rooted in section 112 concepts, and include references to hazardous air pollutant control requirements. EPA must, therefore, place its NSPS emission control standards directly in the text of the NSPS rule.

E. Leak Detection

1. EPA's Proposal

In proposing the revised NSPS, EPA evaluated potential leak detection and repair ("LDAR") requirements for all facilities in the oil and gas production sector. EPA considered four potential LDAR programs: (1) monthly monitoring in accordance with 40 C.F.R. subpart VVa; (2) annual monitoring to the standard imposed by subpart VVa plus monthly optical monitoring; (3) monthly optical monitoring alone; and (4) annual optical monitoring alone.[314] Based on this evaluation, EPA proposes to adopt subpart VVa for processing plants but not to adopt any LDAR requirement for other oil and gas production facilities.

Specifically, under the existing regulation, 40 C.F.R. subpart KKK, § 60.632(a), onshore natural gas processing facilities must comply with subpart VV, but EPA proposes to update the standard to require compliance with subpart VVa.[315] All other facilities are currently unregulated, and EPA concluded that no LDAR program was "cost effective" for these facilities, accordingly declining to adopt a standard.[316]

2. Critique

We agree that subpart VV no longer reflects BSER for onshore natural gas processing plants, and that subpart VVa presents a feasible and cost-effective improvement. Nonetheless, EPA must go further before it is compliant with the statute. It must consider various combinations of subpart VVa and optical monitoring. State programs and consent decrees EPA has entered both demonstrate the efficacy and feasibility of stricter programs with fewer exemptions, and EPA must adopt a stronger standard here.

[313] *See* 76 Fed. Reg. at 52,800 (Proposed 40 C.F.R. § 60.5395(a))
[314] 76 Fed. Reg. at 52,754-55 (discussing processing plants), 52,764-66 (discussing other facilities).
[315] 76 Fed. Reg. at 52,800, (Proposed 40 C.F.R. § 60.5400). Both VV and VVa were developed for the Synthetic Organic Chemicals Manufacturing Industry.
[316] 76 Fed. Reg. at 52,766.

As to other facilities, although EPA determined that an overall LDAR program was unwarranted, EPA must have examined whether LDAR was warranted for particular device types.

a. Processing Plants

The existing VOC regulations for natural gas processing facilities, 40 C.F.R. subpart KKK, incorporate the LDAR provisions of 40 C.F.R. subpart VV. The subpart VV standards were developed in 1981, and subpart KKK was adopted in 1985.[317] Since that time, much has been learned about what it takes to have an effective leak detection program. Notably, investigations by EPA Regional and National Enforcement Investigations Center personnel detected massive fraud in the conduct of LDAR inspections and in the reporting of results.[318] Enforcement action induced negotiations with operators of most of the nation's refineries led to consent decrees that substantially improved the real-world effectiveness of those programs and the development of Best Practice Guidelines.[319] Similarly, various states and regional entities have adopted LDAR programs.[320,] Many of these consent decrees and state regulations are more stringent than the subpart VVa regulation EPA proposes to adopt for processing plants. Yet EPA's BSER review did not examine these activities and practices. EPA must either adopt elements of these more stringent programs as BSER or explain why these elements are infeasible.

The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. Subpart VVa improves upon subpart VV by reducing the leak detection threshold: for pumps in light liquid service, the leak threshold is lowered from 10,000 ppm to 2,000 ppm, and for valves in gas/vapor and

[317] 50 Fed. Reg. 26122 (June 14, 1985) (Exhibit 1); *see also* 50 Fed. Reg. 40158 (Oct. 1, 1985) (Exhibit 2).

[318] In the late 1990's EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation's refineries. Among the most significant violations were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators over 90 percent of the refining capacity in the country. These settlements required improved LDAR practices, $82 million in fines and $75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution. In the absence of a sustained Federal focus on this issue and recognizing the likely lack of state resources in the near future, it would seem that MACT should include some form of independent auditing of LDAR programs. EPA could require an independent audit of sources with large number of components, perhaps once every five years.

[319] See, e.g., Leak Detection and Repair, A Best Practices Guide, p. 22-23, http://www.epa.gov/compliance/resources/publications/assistance/ldarguide.pdf (discussing these consent decrees), attached hereto as Exhibit 108

[320] *See, e.g.*, Bay Area Air Quality Management District regulation 8-18 (adopted Sept. 15, 2004), attached hereto as Exhibit 109

light liquid service, where the leak threshold is lowered from 10,000 ppm to 500 ppm.[321] EPA does not propose to strengthen the monitoring frequency and repair times. The Bay Area Air Quality Management District ("BAAQMD") has demonstrated that stricter regulation is feasible. The BAAQMD supervises LDAR programs at 5 refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than the proposed rule, as summarized in Table 1, below.

Table 1

	Current Rule	Proposed Rule	BAAQMD Rule 8-18
Leak definition – valves in gas/vapor/light liquid services	10,000 ppm	500 ppm	100 ppm
Leak definition – pumps in light liquid service	10,000 ppm	2,000 ppm	500 ppm
Inspection frequency	Monthly/quarterly[322]	Monthly/quarterly	Quarterly/annual[323]
Repair schedule	15 days[324]	15 days	7 days[325]

In addition to having a lower leak threshold, the BAAQMD rule is stricter than the VV and VVa rules because it requires monitoring for methane leaks. Subparts VV and VVa (with incorporation of EPA Method 21) do not specifically require the use of leak detection equipment which is sensitive to methane. Since methane is the main component of natural gas, this oversight can potentially significantly diminish the effectiveness of leak detection at a specified threshold. EPA should therefore either specify that leak-detection equipment be sensitive to methane and adopt BAAQMD's lower threshold or explain why these steps are infeasible for natural gas processing plants.[326]

[321] It should be noted that the 10,000 ppm limit is an absolute limit; while the limit of 500 ppm is "500 ppm above background." Reportedly, background concentrations can be expected to be approximately 100 ppm.

[322] If a component is not found to be leaking in two consecutive months; the inspection frequency is reduced to once per quarter. Thus, the majority of components are inspected quarterly

[323] Pumps are subject to daily visual inspection. If a valve has not been found to be leaking during five quarterly inspections, the inspection frequency is reduced to once per year.

[324] An initial attempt to repair must be made within 5 days.

[325] If the leak is detected by BAAQMD personnel during an inspection it must be repaired within 24 hours. The BAAQMD rules also require that leaks detected by the source be minimized within 24 hours.

[326] As noted, BAAQMD has applied these rules to refineries, chemical plants, and terminals. Although BAAQMD does not appear to regulate any natural gas processing plants, EPA has historically subjected natural gas processing plants to the same regulations as these other facility types.

Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. Subpart VV exempts devices from monitoring if it is "unsafe" or "difficult" to monitor them.[327] Subpart VV further allows operators to delay repair of leaking devices: an operator may delay repair of devices where repair would require a shutdown of the process, and an operator may forgo repairs of 2% of the total number of devices provided the operator conducts weekly rather than monthly monitoring.[328] These exemptions were carried over into Subpart VVa.[329] EPA must review these exemptions in light of the experience in California and elsewhere and determine whether exemptions at these levels continue to be consistent with the notion of "best system of emission reductions." For example, BAAQMD does not recognize an exemption for devices that are unsafe to monitor. Similarly, whereas the proposal would allow 2% of devices to be designated as nonrepairable, BAAQMD limits the number of nonrepairable devices to 0.025% to 1%, depending on the device category.[330]

A particularly troubling exemption in EPA's proposed standard is that EPA proposes to waive LDAR requirements where the gas stream is less than 10% VOC by weight. Proposed subsection 60.5400(f) states that:

> [e]ach piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process.

EPA's preamble provides no discussion of this exemption, and we are aware of no basis for it. This LDAR exemption will likely apply to many, if not all, compressors, valves, pressure relief devices and connectors downstream of processing unit dehydrators; indeed, EPA reports that processed gas is only 2.8% VOC by weight.[331] Although devices used with low-VOC gas streams will by definition have lower VOC emissions, VOC leaks from these devices may still be significant. Addressing these leaks will certainly have important methane benefits. Accordingly, EPA must either remove the exemption or provide a justification for continuing to provide it.

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[327] 40 C.F.R. §§ 60.486(f), 60.482-2(g), 60.482-7(g)-(h), 60.482-10(j)-(k).
[328] 40 C.F.R. §§ 60.483-1, 60.482-7(a)(2)(ii).
[329] 40 C.F.R. §§ 60.486a(f), 60.482-2a(g), 60.482-7a(a)(2)(ii), (g), (h), 60.482-10a(j)-(k), 60.482-11a(e), 60.483-1a, 60.483-2a(b).
[330] The BAAQMD limit on the number of non-repairable components it 0.3 percent for valves, 0.025 percent for valves with major leaks (leaks greater than 10,000 ppm, including methane) and 1.0 percent for pumps and compressors. It also requires mass emission testing for non-repairable components with high leak rates and places an emission limit of 15 pounds per day on non-repairable components. The SCAQMD limit is 0.5 percent for valves and 1.0 percent for pumps.
[331] *See* TSD at 6-2.

The LDAR program furthermore must incorporate elements beyond thresholds and schedules. The alternate compliance option and allowable level of designated “difficult to monitor” valves must be reviewed in light of the performance of best performing LDAR programs. For example, EPA must limit the exemptions for devices that are difficult or unsafe to monitor or repair by providing that when such devices are replaced, they must be replaced with hermetically sealed (leakless) designs. Use of advanced “leakless” components in these locations should be cost-effective since (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations; (2) the conversion to leakless technology would only occur when a new valve is being installed; and (3) the potential emissions from leaking “inaccessible” components is greater since a leak is less likely to be observed visually or by sense of smell and instrumented monitoring only occurs annually. Since the NSPS only applies to newly installed components, advanced technology components must be required at the time of initial installation for those components that, if they leaked, would require a plant shutdown to repair. EPA must also explore whether optical scanning provides a way to monitor devices that would be difficult or unsafe to monitor using traditional monitoring techniques.

Another approach EPA must use is to require "repeat offenders" to be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than, *e.g.*, 5 times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.[332]

Finally, EPA must ensure the integrity of the LDAR program. As EPA's history of enforcement actions demonstrates, this integrity cannot be taken for granted.[333] EPA has, as we note above, encountered significant fraud in previous leak detection efforts. To avoid this, it must include safeguards in its rules, including requiring a professional engineer to sign off on all LDAR reports. EPA must also explore requiring periodic independent audits of LDAR programs, at least for larger processing plants.

Optical Scanning

In three of its four options, EPA considered the use of optical scanning devices as a means of reducing LDAR inspection frequencies, and EPA specifically requested comment on the role of optical scanning. Current and even advanced LDAR programs

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[332] See, SCAQMD Rule 1173(g)(3), attached hereto as Exhibit 110 and Ventura County APCD Rule 74.7, attached hereto as Exhibit 111. Under the Ventura County rule, for example, if a valve is found to have suffered 5 major leaks in a year is shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

[333] For a more recent example, see EPA’s recent refinery settlements. See, e.g. http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html, attached hereto as Exhibit 116.

have been shown to be cost-effective BSER. EPA is correct that optical scanning devices have not been shown to be as effective as LDAR programs, and, as pointed out, cannot quantify emissions. Optical scanning programs can, however, be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low cost means of filling the gaps in the LDAR program. Daily or weekly scans can identify plant areas containing gross emitters (including "unsafe to monitor" or "difficult to monitor" components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks early, while improving the environmental performance of the facility. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For this reasons these options must be considered in addition to and not *in lieu of* existing programs.

Defining affected facilities

The Clean Air Act provides that NSPS apply to "stationary source[s]," which include individual "facilit[ies]." CAA §§ 111(a)(3), (b)(1). Each individual NSPS defines the "affected facilities" it regulates. *Star Enter. v. EPA*, 235 F.3d 139, 142 (3d Cir. 2000), *Sierra Pac. Power Co. v. EPA*, 647 F.2d 60, 66 (9th Cir. 1981).

The proposed regulation, as it applies to onshore natural gas processing plants, defines "affected facility" to include two things: an individual "compressor in VOC service or wet gas service," or "[t]he group of all equipment, except compressors, within a process unit." Proposed 40 C.F.R. § 60.5365(f)(1)-(2). "Process unit" is defined as "components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products." § 60.6430.

Operators and enforcement staff are likely to disagree over what constitutes a "process unit." The definition must be expanded to include all common gas processing processes, as follows:

> Gas processing plant process unit means equipment assembled for dehydration of natural gas, the sweetening of gas, the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

b. Non-Processing-Plant facilities

EPA does not propose any form of LDAR for non-processing-plant facilities, including the wellheads, compressors, pneumatics, and storage facilities otherwise regulated by the proposal.[334] EPA concluded that the two options involving subpart VVa-type monitoring were not "cost effective." [335] For the two options involving solely optical monitoring, EPA was "unable to estimate their cost effectiveness" because EPA could not estimate the amount of VOC reductions these programs would achieve.[336]

At a minimum, EPA must evaluate whether monitoring is BSER for specific components, and justify its decision not to apply it. For example, EPA concluded that Subpart VVa had a cost of control of $6,079 per ton of VOC as applied specifically to valves at gathering lines and boosting stations, and that modified subpart VVa as applied to these same valves had a cost effectiveness of $5,221 per ton.[337] Although EPA has not articulated a cutoff for reasonable control costs, these numbers resemble other figures that EPA has concluded are cost effective. For example, in discussing LDAR for processing plants, EPA concluded that switching from subpart VV to subpart VVa would have a cost-effectiveness of $3,352 per ton of VOC, including $4,360 for connectors, and that this was cost-effective.

Furthermore, it appears that EPA's cost estimates are unduly conservative, in that two prior studies found LDAR programs to be more cost-effective than does the current proposal. EPA's own 2009 Methane to Markets presentation identified drastically lower LDAR costs per device monitored.. A separate Canadian study determined that, *inter alia*, 75 to 85 percent of leaks are economic to repair. Thus, EPA may be overstating the cost of LDAR programs for non-processing-plant facilities, and EPA must at least reconcile its current cost estimates with those in EPA's 2009 Methane to Markets report.

F. SO_2 Emissions from Gas Processing Plants

1. EPA's Proposal

Gas processing plants are significant SO_2 sources because the removal of H_2S from "sour" gas results in SO_2 emissions.[338] EPA's Subpart LLL control standards, which are calibrated by the sulfur feed rate at a given facility, set a maximum required control efficiency of 99.8% for facilities with sulfur feed rates greater than 5.0 long tons/day

[334] 76 Fed. Reg. at 52,766.
[335] *Id.*
[336] *Id.* at 52,765-66.
[337] 76 Fed. Reg. at 52,765.
[338] *See* 49 Fed. Reg. 2,656, 2,658 (Jan. 20, 1984) (describing these emissions), attached hereto as Exhibit 117.

(LT/D) and a gas stream with greater than 50% H_2S content.[339] These standards were set in 1984, and EPA now proposes to update them. A database search shows two facilities which meet EPA's feed rate and H_2S content standards which can achieve a 99.*9*% control efficiency.[340] EPA therefore proposes to raise its maximum control efficiency to 99.9%, consistent with these achieved emissions reductions.

2. BSER Determination

We agree with EPA that, as facilities with high sulfur feed rates can achieve a 99.9% control efficiency, the existing 99.8% feed rate no longer reflects BSER/BDT. We therefore support EPA's decision to raise the maximum required control efficiency consistent with control rates achieved by the sources in EPA's database.

G. Conclusion

In sum, EPA's proposal is a substantial improvement over the status quo, but must be improved to be fully compliant with section 111's forward-looking technology forcing requirements as we describe above.

III. EPA MUST ADD SEVERAL MISSING SOURCE TYPES TO THE NSPS

Throughout these comments, we have noted opportunities for EPA to control certain source categories which the rules do not now appear to cover, including conventional well liquids unloading and produced water ponds and tanks. Three other omitted source types are also important here, and must be included in the standards because section 111, as we discuss above, requires EPA to comprehensively regulate each listed source category (or justify its failure to do so) upon each eight year review and revision. These source categories are: (a) offshore sources, (b) heater-treaters; and (c) oil and gas field engines, including rig engines.

A. Offshore Sources

EPA has the authority, and the obligation to regulate the emissions of portions of the offshore oil and gas production sector. The Outer Continental Shelf Lands Act ("OCSLA") explicitly *extended* the "laws and civil and political jurisdiction of the United States" to the Outer Continental Shelf, cementing the relevance of domestic environmental law to that region.[341] In doing so, Congress recognized that the shelf is "a vital national resource reserve held by the Federal Government for the public," and which is "subject to environmental safeguards."[342] In fact, Congress even ordered the Secretary of the

[339] *See* 40 C.F.R. § 60.642.
[340] 76 Fed. Reg. at 52,755-56.
[341] *See* 43 U.S.C. § 1333(a)(1).
[342] *See* 43 U.S.C. § 1332(3).

Interior, who oversees leasing programs in the region, to “cooperate with the relevant departments and agencies of the Federal Government” to enforce “environmental laws.”[343]

The Clean Air Act provides, in turn, that following the passage of the 1990 Amendments, EPA:

> [s]hall establish requirements to control air pollution from Outer Continental Shelf sources located offshore of the States along the Pacific, Arctic, and Atlantic Coasts, and along the United States Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes (“OCS sources”) to attain and maintain Federal and State ambient air quality standards *and* to comply with the provisions of [the Prevention of Significant Deterioration Program].[344]

Section 111 standards are, of course, designed to “supplement” ambient air quality standards by ensuring that new and modified sources of air pollution in all areas comply with rigorous emissions controls.[345] As such, EPA must extend these regulations to “attain and maintain” air quality to OCS sources.

The Act goes on to specify that, for OCS sources “located within 25 miles of the seaward boundary of such states”:

> such requirements shall be the same as would be applicable if the source were located in the corresponding onshore area, and shall include, but not be limited to, State and local requirements for emission controls, emissions limitations, offsets, permitting, monitoring, testing, and reporting.[346]

The NSPS clearly fit within this inclusive collection of requirements, even though they are federal requirements, as they are, again, regulations designed that support attainment and maintenance of air quality standards. And the use of “shall” in the directive from Congress to establish regulations aimed at attaining and maintaining the NAAQS and comply with the PSD program indicates that EPA must extend the NSPS in over Outer Continental Shelf sources.

Significantly, Congress declared that EPA “shall update such requirements as necessary to maintain consistency with onshore regulations.”[347] Because EPA is updating the NSPS for onshore sources, it must therefore update and extend the NSPS to corresponding offshore sources within the 25 mile boundary.

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[343] *See* 43 U.S.C. § 1334(a).
[344] 42 U.S.C. § 7627(a)(1).
[345] *See*, *e.g.*, *NRDC v. Train*, 545 F.2d 320 (2nd Cir. 1976), attached hereto as Exhibit 118.
[346] 42 U.S.C. § 7627(a)(1).
[347] *Id.*

It is particularly important that EPA do so because emissions from offshore sources are significant. Indeed, according to EPA's most recent greenhouse gas inventory, in petroleum systems:

> The most dominant sources of emissions, in order of magnitude, are *shallow water offshore oil platforms*, natural-gas-powered high bleed pneumatic devices, oil tanks, natural-gas powered low bleed pneumatic devices, gas engines, *deep water offshore platforms*, and chemical injection pumps. These seven sources alone emit about 94 percent of the production field operations emissions. Offshore platform emissions are a combination of fugitive, vented, and unburned fuel combustion emissions from all equipment housed on oil platforms producing oil and associated gas.[348]

Because VOCs are generally co-emitted with methane, especially in the production segment, offshore sources also will be significant VOC sources.

Yet, EPA neither proposes standards for offshore oil and gas production, nor justifies its failure to do so. The Clean Air Act requires EPA propose and finalize such standards.

B. Heater-Treaters

Heater-treaters, which are small boilers used to separate oil and gas emulsions, are common in both oil and gas fields, but EPA has not proposed standards for them. It must do so.

Although individual heater-treaters are relatively small sources of NO_x and CO, thousands of them are used in the production process. As the Colorado Department of Public Health and Environment explained in its recent regional haze state implementation plan, although individual heater-treaters "often fall below regulatory thresholds," there are huge numbers of such sources in use and projected for the future – 26,000 are projected by 2018 in Colorado alone.[349] As a result, heater-treaters will be the largest single area source NO_x emitters in Colorado by that year, emitting 22,901 tons per year of NOx, plus 4,809 tons per year of CO.[350]

To address these emissions, EPA has recommended voluntary use of operational standards, and numerous California air districts have set emissions standards. To wit:

- EPA recommends that operators reduce heater-treater temperatures to the minimum effective temperature. EPA notes that these combustion savings will

[348] EPA, *Inventory of U.S. Emissions and Sinks 1990-2009* (2011) at 3-49.
[349] Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011)
[350] *Id.*

reduce methane emissions by 142 Mcf per year per heater-treater, paying for themselves in fuel savings.[351]

- The San Diego County Air Pollution Control District sets emissions standards for small boilers and process heaters (with heat inputs between 600,000 BTU to 2 million BTU/hr) of 30 ppm NOx (for gaseous fuels), 40 ppm NO_x (for liquid fuel), and 400 ppm CO. .[352]

- The South Coast Air Quality Management District sets emissions standards for NOx from boilers, steam generators, and process heaters with heat inputs between 2 million and 5 million BTU. By 2008, operators were required to cut their emissions to 30 ppm NO_x (or 0.037 lb NO_x /mmBTU for gas-fired units). By 2015, emissions must fall further, to 12 ppm for atmospheric units, and 9 ppm for natural-gas fired units. CO emissions are limited to 400 ppm.[353]

- The San Joaquin Valley Air Pollution Control District sets emissions standards for small boilers, steam generators, and process heaters with heat inputs between 75,000 BTU and 2 million BTU/hr. As of January 2011, units below 400,000 BTU were limited to 0.024 lb NO_x /hr (for gas-fired units) and 0.093 lb NOx/hr (for non-gas units); larger gas units must meet the same standard, while larger non-gas units must meet a 0.036 lb NO_x /hr standard. All units are limited to a 400 ppm CO standard.[354]

- The Ventura County Air Pollution Control District's small boiler, steam generator, and process heater rules apply to units with heat inputs between 1 million and 5 million BTU/hr. Such heaters are limited to a 30 ppm NO_x standard and a 400 ppm CO standard.[355]

- The Santa Barbara County Air Pollution Control District small boilers, steam generators, and process heaters rules covers units with heat inputs between 2 million and 5 million BTU/hr. It, too, imposes a 30 ppm NO_x and 400 ppm CO standard.[356]

[351] EPA Natural Gas STAR, *Lower Heater-Treater Temperature, PRO Fact Sheet No. 906*, attached hereto as Exhibit 119.
[352] SDCAPCD Rule 69.2.1, attached hereto as Exhibit 120
[353] SCAQMD Rule 1146.1, attached hereto as Exhibit 121.
[354] SJVAPCD Rule 4308, attached hereto as Exhibit 122.
[355] VCAPCD Rule 74.15.1. attached hereto as Exhibit 123.
[356] SBCAPCD Rule 361, attached hereto as Exhibit 124.

Controls can be imposed in various ways, running from simply lowering heater-treater temperatures and insulating units to tuning heater-treaters regularly to increase combustion efficiency, as many of the California air districts require.[357]

In short, heater-treaters are extremely numerous NO_x and CO emissions sources found throughout oil and gas fields. These emissions are readily subject to control and have been controlled, for years, by California regulators. But because each individual heater-treater's emissions will be relatively minor, heater-treaters are unlikely to be directly regulated in many states, or under federal major source permitting programs. Section 111 regulation is necessary, as a practical matter, to ensure that this cumulatively major emissions source is properly controlled.

Yet EPA fails even to recognize this facility type, much less set standards. EPA must set standards no less stringent than those employed in the California air districts (that is, at least no less stringent than the common 30 ppm NO_x and 400 ppm CO standard).

C. Field Engines and Turbines, Including Drilling Rig Engines

EPA acknowledges that "[s]ignificant emissions of [NO_x] . . . occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors through the system, and from combustion of natural gas in heaters and boilers."[358] But EPA declines to control these emissions because it asserts that these sources, though "co-located" on production sites, are "not in the Oil and Natural Gas source category" and instead are addressed by the subpart JJJJ and KKKK performance standards. EPA also, without discussion, excludes drilling rig engines from its standards. EPA does not support its decision to exclude these sources from its proposal, nor show that other standards are sufficient to control their emissions.

Emissions from this equipment have been implicated in significant air quality problems in several areas. For example, in the Pinedale Anticline supplemental environmental impact statement in Wyoming, NO_x emissions from drill rigs were estimated at 2,590 tons per year (tpy) in 2005 and 3,232 tpy in 2009 under the proposed action.[359] This represents more than six times the NO_x emissions from compression activities and 5.8 to 6.1 times the fugitive NO_x emission rates from pad construction, traffic, and completions.

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[357] *See, e.g.*, VCAPCD Rule 74.15.1 Att. 1 (describing tuning procedure); SCAQMD Rule 1146.1 Att. 1 (same).
[358] 76 Fed. Reg. at 52,756.
[359] *Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Proje*ct at 11 (Table 2.1), "Pinedale SEIS TSD," attached hereto as Exhibit 125.

NO_x emissions are a significant precursor of very harmful ozone events and of visibility impairment in nearby Class I areas. Ozone levels have exploded in the Pinedale, Wyoming area, reaching 8-hour averages of 122 parts per billion in February, 2008.[360] Emissions from natural gas production, particularly NO_x, have been implicated in these highly unusual winter-time ozone extremes.[361] Visibility impairment due to direct project source emissions has reached 45 days per year with over 1 dv of visibility impairment—6.1 dv maximum visibility impact—in 2005 in the Bridger Wilderness Area.[362]

Thus, EPA must address NO_x emissions (and emissions of other pollutants) from these sources, or demonstrate that they are sufficiently addressed by other Clean Air Act standards. It must take further action to do so, in several regards:

First, EPA must close relevant gaps in coverage of the performance standards for engines and turbines used in the oil and gas sector, such as NSPS Subparts IIII, JJJJ, and KKKK, and the non-road mobile source engine rules. One clear gap is the current exemption for turbines with heat inputs below 10 million BTU per hour.[363] These sources are plainly part of the oil and gas source category, and EPA must include them in its standards, yet it has not.

Second, as we discuss above, subparts IIII, JJJJ, and KKKK do not address all pollutants from engines and turbines used on production sites. Most notably, compressor exhaust contains significant amounts of methane,[364] which is not controlled by the subpart JJJJ and KKKK standards. These emissions will go uncontrolled unless EPA issues revised standards, perhaps in a supplemental proposal.

Third, because EPA is obligated to ensure that its review and revision of its standards for the oil and gas sector is complete, it must demonstrate on the record that all significant pollution sources from the sector have been addressed. As such, EPA must provide a clear analysis of emissions from drill rigs and other oil and gas field engines, showing (1) the types and numbers of engines that are not regulated under other provisions; (2) the emissions resulting from any gap in regulatory coverage, and (3) a description of how EPA plans to address these emissions, if it declines to promulgate standards in this

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[360] Wyoming Dept. of Enviro. Quality, (2008) "Air Pollution Advisory: Ozone For Upper Green River Basin/Sublette County," 27 February 2008. http://www.pinedaleonline.com/news/2008/02/AirPollutionAdvisory.htm, attached hereto as Exhibit 126.

[361] Schnell, R.C, et al. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415.

[362] Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project, Vol. 2, at 16-9 (Table 16.9) and 18-13 (Table 18.16). attached hereto as Exhibit 127.

[363] 40 CFR § 60.4305.

[364] *See supra* Section X.

rulemaking. In other words, EPA may not simply assert that these emissions are controlled elsewhere; it must demonstrate that that is the case.

IV. EPA MUST ADD STANDARDS FOR SEVERAL MISSING POLLUTANTS TO THE NSPS

EPA must regulate each dangerous pollutant emitted by sources in the oil and gas source category in more than *de minimis* quantities,[365] for which controls are available. It has failed to do so. This failure is serious: It leaves dangerous pollutants unregulated. In particular, EPA must regulate methane, particulate matter, hydrogen sulfide, and nitrogen oxides from oil and gas operations. EPA's explanation of why it declined to regulate certain pollutants does not even discuss particulate matter or hydrogen sulfide, or address the most important sources of nitrogen oxides, and does not offer a legal justification for its failure to regulate methane.

EPA's duties to regulate these pollutants arise directly from the statutory text, and from decades of agency practice.

Congress clearly intended Section 111 to address the full scope of air pollution emitted by a source category. The plain language of section 111 requires no less, repeatedly referring to the regulation of "any" air pollutant emitted by sources subject to regulation under this section. For example, Congress defined stationary sources to which NSPS apply as including facilities that emit or may emit "any air pollutant."[366] Likewise, Congress defined "modification" of existing sources – which in turn become subject to the NSPS – as "any physical change in, or change in method of operation of, a stationary source which increases the amount of *any* air pollutant emitted . . . or which results in the emission of *any* air pollutant not previously emitted."[367] That Section 111 applies to sources of "any" air pollutant is strong evidence that the Section is designed not only to *apply* to those sources but to *control* pollution resulting from "any" pollutant.[368]

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[365] Any such de minimis exemption would have to be thoroughly justified on the record; such exemptions are not routinely available.
[366] 42 U.S.C. § 7411(a)(3).
[367] *Id*. § 7411(a)(4) (emphases added).
[368] The Act provides additional evidence of Congress's intent to require EPA to establish NSPS for all pollutants emitted by a source category. Section 111(f) was inserted in response to EPA's prior challenges in promptly establishing NSPS for source categories listed under section 111(b). Under section 111(f), Congress placed EPA on a timetable to complete a specified number of delinquent NSPS by dates certain. To determine which categories should be dealt with first, Congress gave EPA three factors to consider:

> (A) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;
> (B) the extent to which *each such pollutant* may reasonably be anticipated to endanger public health or welfare; and
> (C) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new sources standards of performance

EPA must, likewise, consider "any" air pollutant emitted by a source when it reviews an existing NSPS. Section 111 provides that EPA "*shall*, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[369] Accordingly, if in EPA's judgment a category of sources "causes, or contributes significantly to" emissions that result in air pollution that may be reasonably anticipated to endanger public health or welfare, the Act requires EPA to add the category to a list, issue standards of performance applicable to that category, and review such standards on a prescribed schedule. Section 111 therefore creates an explicit, time-bound requirement for periodic review and updating of the performance standard for each category of stationary sources for all emitted air pollutants.

EPA must, in short, every eight years, (1) review its standards (as it has done here), (2) determine whether it is "appropriate" to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly. Again, because Congress intended EPA to reach each and any pollutant emitted by a regulated source category, this review must encompass all pollutants emitted by that source category.

EPA has long interpreted this "appropriateness" determination to turn on two (and just two) factors: (1) the amount of emissions of a given pollutant from that source category and (2) the availability of demonstrated control measures.[370,371] As EPA explained in its recent NSPS for the cement industry: "We have historically declined to propose standards for a pollutant where it is emitting in low amounts or where we determined that a BDT analysis would result in no control *National Lime Assoc'n v. EPA,* 627 F.2d at 426."[372,373] In 1985, for example, EPA decided not to revise the cement kiln standards to regulate NO_x and SO_2 emissions, based on the absence of demonstrated control technology.[374] By 2010, however, EPA found that circumstances had changed such that

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Congress thus ordered EPA to focus upon "each" pollutant emitted by these sources. Because section 111(f) standards are no different than any other NSPS – the section merely required EPA to complete unfinished standards – Congress's focus on "each" pollutant emitted by tardy sources speaks to section 111 generally, demonstrating that Congress, indeed, intended EPA's standards to control *each* pollutant emitted by such sources.

[369] *Id.* (emphasis added).

[370] *See, e.g.*, 50 Fed. Reg. 36,959, 36,961 (Sept. 10, 1985) (making negative determination based on lack of demonstrated control technology), attached hereto as Exhibit 128; 75 Fed. Reg. 54,994–95 (Sept. 9, 2010) (making positive determination based on significant emissions and existence of demonstrated control technology), attached hereto as Exhibit 129.

[371] *See also Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n. 27 (discussing these factors)

[372] 75 Fed. Reg. 54,970, 54,996-97 (Sept. 9, 2010), attached hereto as Exhibit 129

[373] *See, e.g.*, 41 Fed. Reg. 3,826, 3,827 (Jan. 26, 1976) (finding that carbon monoxide and SO_2 standards were not appropriate for aluminum smelters because technology was not demonstrated (SO_2) and emissions were insignificant (CO)), attached hereto as Exhibit 130.

[374] 50 Fed. Reg. 36,959, 36,961.

it was now appropriate to set standards for NOx and SO_2 because cement kilns emitted substantial quantities of each pollutant and demonstrated control technologies were available[375]

Thus, inherent in EPA's duty to review the oil and gas NSPS is the duty to determine, with regard to "any" air pollutant emitted by the industry, whether it was "appropriate" to regulate that pollutant. This determination, again, turns on whether the pollutant is emitted in more than *de minimis* quantities and whether control technology is available.

EPA here has failed to carry out this duty with regard to methane, particulate matter, hydrogen sulfide, and nitrogen oxides. For each of these pollutants, it has either made an unlawful decision not to regulate, or unlawfully and unreasonably omitted any consideration of the issue. It must correct these errors.

A. EPA Must Regulate Methane

1. The Clean Air Act Requires EPA to Promulgate NSPS for Methane

Methane is a potent greenhouse gas that contributes to climate change. The Supreme Court recently found that methane comes within the broad scope of the Act's definition of "air pollutant" as defined under the Act, 42 U.S.C. § 7602(g), stating: "On its face, the definition embraces all airborne compounds of whatever stripe, and underscores that intent through repeated use of the word 'any.'" *Massachusetts v. EPA,* 549 U.S. at 529. As a result, EPA has explicitly found that methane is a component of an air pollutant that endangers public health and welfare within the meaning of the Clean Air Act.[376]

EPA acknowledges, as it must, that the oil and gas sector "emit[s] significant amounts of methane" – the equivalent of 251.55 million metric tons of CO_2 according to EPA's most recent inventory.[377] Indeed, EPA has identified the oil and gas industry as the "single largest contributor to United States anthropogenic methane emissions."[378] These emissions make the industry the second largest stationary source of greenhouse gas pollution in the country, and the largest single industrial source of methane pollution. Control technologies for methane are readily available. EPA's decision not to regulate a major category of emissions of this potent greenhouse gas therefore is illegal.[379]

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[375] 75 Fed. Reg. 54,994–95.

[376] *Endangerment and Cause or Contribute Findings for Greenhouse Gases*, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding")

[377] 76 Fed. Reg. at 52,756.

[378] 76 Fed. Reg. at 52,792 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011)) .

[379] Though it discussed a different industry – fossil-fuel fired power plants – the Supreme Court recently recognized that the NSPS program is an appropriate mechanism for regulating CO_2, another greenhouse gas. *See AEP v. Connecticut*, 131 S.Ct. 2527, 2537-38, __ U.S. __ (2011), attached hereto as Exhibit 131, ("We think it equally plain that the Act 'speaks directly' to emissions of carbon dioxide from the defendants' plants. . . . Once EPA lists a category, the agency must establish standards of performance for

EPA offers no reasonable rationale for its failure to set standards for methane. It says only:

> Although this proposed rule does not include standards for regulating the [methane] emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.[380]

This rationale, such as it is, cannot be squared with either the statute or EPA's regulatory practice.

EPA cannot decline to complete its review duty, nor defer making an appropriateness finding. As we explain above, section 111 requires EPA to "at least every 8 years" review and, "if appropriate" revise its standards.[381] EPA must, on this review, make a final appropriateness finding, and either include methane or determine it is not appropriate to do so. It cannot delay its decision because the NSPS are designed to force pollution controls, and concomitant air quality improvements, on a statutorily-mandated timeline.

Thus, for purposes of completing its mandatory review duty as set forth above, EPA has made an affirmative decision *not* to regulate methane that both fails to apply the agency's own criteria for determining whether such a revision is appropriate, and runs directly counter to the evidence in the record. Again, EPA, as a matter of long-settled practice, has interpreted the "appropriateness" finding to turn on only two factors – the quantity of pollutant emitted and whether control technology exists to control that pollution. It cannot alter this long-standing statutory interpretation without rulemaking, and it has issued no proposal to do so. Thus, EPA is bound by its own interpretation. *See, e.g. Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 41 (1983).

On that interpretation, EPA can make only a positive appropriateness finding. The agency itself concedes that "processes in the Oil and Natural Gas source category emit significant amounts of methane." 76 Fed. Reg. at 52756. Indeed, this industry is

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emission of pollutants from new or modified sources within that category. § 7411(b)(1)(B); *see also* § 7411(a)(2). And, most relevant here, § 7411(d) then requires regulation of existing sources within the same category [unless sources of the pollutant in question are regulated under the national ambient air quality standard program, §§7408-7410, or the HAP program, § 7412].").

[380] 76 Fed. Reg. at 52,756.

[381] 42 U.S.C. § 7411(b)(1)(B).

responsible for over 40% of total U.S. methane emissions.[382] This amounts to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[383]

Moreover, in describing why it chooses not to regulate methane, EPA acknowledges that technology exists that that would enable an emission limit for methane.[384] Indeed, there are numerous demonstrated control technologies for regulating methane from the oil and gas industry that consistent BSER, many of them endorsed or developed by EPA itself through its Natural Gas STAR and Methane to Markets programs.

These control technologies not only substantially reduce emissions, but also in many cases produce profits for industry.[385] EPA has recognized that the control technologies it has proposed for VOCs will indirectly reduce baseline methane emissions for the oil and gas sector by 26%.[386] EPA also predicts industry will make $45 million annually by implementing the rules.[387] For example, EPA notes that the ability to sell natural gas captured by using the proposed equipment and work practices for "green completions" would produce a net *savings* of $99 per ton of VOC reduced.[388] Moreover, according to EPA, the climate co-benefits of the methane reductions amount to as much as $1.6 billion by 2015.[389]

Finally, EPA's statement that many of its VOC controls will also yield *de facto* methane reductions, though true, is beside the point. Not only does this assertion have nothing to do with the appropriateness factors, it also ignores the fact that methane and the VOCs which EPA *has* regulated do not overlap in ways that ensure reliable and complete methane controls. The pollutants are emitted in different ratios from various devices and sources, and so simply are not interchangeable. Further, as discussed above, some measures that EPA has rejected as having unreasonable control costs for VOC reduction, have reasonable costs when the value of methane reductions is considered.

In short: Methane is emitted in significant amounts by sources in this industry even though there is control technology readily available to reduce such emissions. Moreover, EPA has already determined that methane, an air pollutant under the Act, endangers public health and welfare.[390] Based on the plain language of section 111,

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[382] *See* 76 Fed. Reg. at 52,756, 52,791-92; *see also* EPA, Sources and Emissions/Methane, *available at* http://www.epa.gov/outreach/sources.html, attached hereto as Exhibit 132.
[383] *Id.* at 52,791–92 (citation omitted).
[384] *See* id. (explaining that some methane reduction will occur because "many of the proposed requirements for control of VOC emissions also control methane emissions").
[385] *See, e.g.*, MEGAN WILLIAMS & CINDY COPELAND, METHANE CONTROLS FOR THE OIL AND GAS PRODUCTION SECTOR at 1 (2010) (submitted to EPA under separate cover on November 23, 2010)at 1.
[386] 76 Fed. Reg. at 52,792.
[387] 76 Fed. Reg. at 52,791.
[388] 76 Fed. Reg. at 52,758.
[389] *Id.* As our discussion above indicates, these benefits may be even larger.
[390] 74 Fed. Reg. at 66,516, attached hereto as Exhibit 134.

EPA is required to include methane standards in the final rule NSPS for new and modified sources from oil and natural gas operations, as well as standards under section 111(d) for existing sources of methane within the industry.

2. EPA's Failure to Regulate Methane is Unreasonable

While section 111 requires EPA to regulate methane emissions from oil and natural gas operations, to the extent EPA possesses any discretion in the matter, its decision not to regulate methane in this rulemaking is an abuse of such discretion and must be corrected in the final rule or a supplemental rule. EPA has not attempted to justify its decision not to regulate methane emissions in the proposed rule, except to say that it "continue[s] to assess these significant emissions and evaluate appropriate actions for addressing these concerns."[391] This "justification" is not just unlawful, but unreasonable.

First, it bears repeating that EPA's standards, as proposed, fail to capture the lion's share of methane emissions from the industry. EPA estimates that co-benefit methane reductions from its rules will amount to about 26% of the industry's methane emissions.[392] The remaining 74% of methane (much, but not all, of it from existing sources) goes uncontrolled. Moreover, even the 26% reduction that EPA cites is not enforceable, as it arises only incidentally from VOC reductions.

Given the demonstrated cost-effective nature of the control technologies for regulating methane, EPA could go much further to capture a large percentage of the remaining 74% of methane emissions left on the table with this rule. As noted above, the varying ratios of VOC to methane of various devices and sources in the gas industry mean that VOC regulations cannot serve as a surrogate for methane controls. Opportunities for EPA to achieve additional methane reductions are summarized below and explained in detail in the attached report by Megan Williams and Cindy Copeland.

Moreover, failing to directly regulate methane emissions also poses serious threats to public health and welfare: Methane, as we have explained, is a potent greenhouse gas, causing climate change that will threaten public health and welfare, as EPA recognized in its Endangerment Finding. Methane contributes significantly to ozone formation.[393] In order to protect the public by ensuring substantial, enforceable methane reductions, EPA must promulgate standards to control both of these pollutants at all sources.

Finally, EPA's decision not to regulate a major category of emissions of this potent greenhouse gas is simply bad policy. Based on EPA's own estimates, the oil and gas sector within the U.S. is responsible for over 40% of the country's total methane

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[391] 76 Fed. Reg. at 52,756.
[392] *Id.* at 52,792.
[393] *See, e.g.*, *id.* at 52,791.

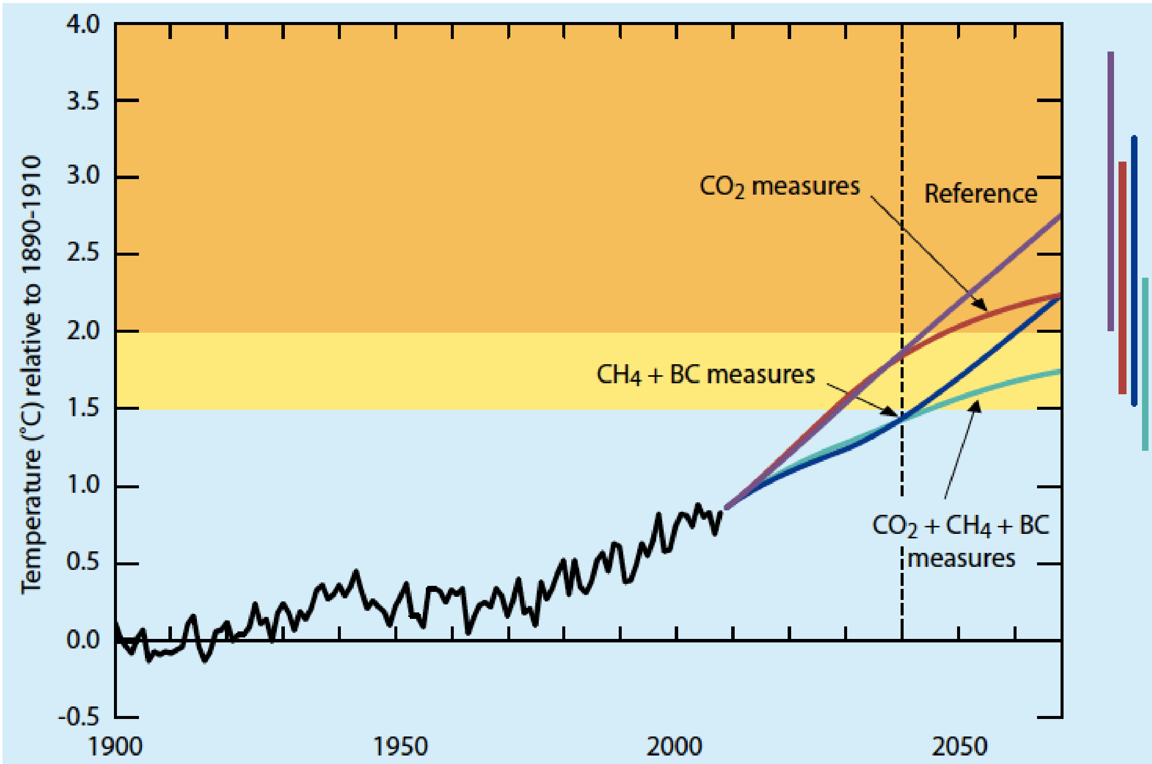
emissions.[394] Though the proposed rule will result in some reductions in methane emissions as an indirect byproduct of regulating VOC emissions, significant amounts of methane emissions will continue uncontrolled. Control technology that represents BSER within the oil and natural gas sector is available for capturing these emissions. While we commend EPA on its efforts to reduce VOC emissions, the Clean Air Act and EPA's own practices require the direct regulation of methane. The Agency's own finding that the greenhouse gas pollution of which methane is a part endangers human health and welfare demonstrates the significance of failing to regulate significant sources of methane

Methane is a potent greenhouse gas that contributes to climate change. As EPA explains in the proposed rule, "once [methane is] emitted into the atmosphere, [it] absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change."[395] Methane also reacts in the atmosphere to form ozone, which increases global temperatures.[396] Methane has 25 times the global warming potential of carbon dioxide over a 100 year time frame, and 72 times the global warming potential of carbon dioxide over a 20-year time frame.[397] The impacts of warming cause by methane and other greenhouse gases include "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."[398]

Methane's climate potency and short lifetime makes controlling methane emissions now particularly critical. While reductions of carbon dioxide emissions are essential to mitigate climate change, CO_2 *already emitted* will continue to warm the climate at dangerous rates and to dangerous levels (due to it's long lifetime in the atmosphere) if other climate warmers with shorter lifetimes are not addressed. Figure XX, from the recent UNEP report, illustrates how mitigating short-lived forcers (in this case both methane and black carbon (BC)) is an essential approach to reducing temperature rise in the coming decades. Reductions of BC and methane are essential to slow down rapid warming, *and* to reduce the peak of the warming. Conversely, if we allow methane emissions to continue to significantly increase (as they will do if the oil and gas industry is allowed to operate without a strong methane NSPS), those emissions will substantially increase the pace and severity of climate change.

Figure 5

[394] 76 Fed. Reg. at 52,756.
[395] 76 Fed. Reg. at 52,791.
[396] 76 Fed. Reg. at 52,791.
[397] IPCC 2007—The Physical Science Basis, Section 2.10.2.
[398] *Id.* at 52,791–92



Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).

Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.[399]

Methane's near term contribution to climate change is expected to have dire consequences on human health heat-related mortalities, the spread of infectious disease vectors, greater air and water pollution, and increase in malnutrition, and greater casualties from fire, storms and floods. Increased average temperatures are also expected to increase the number of heat waves.[400] This will have a particularly detrimental effect on vulnerable populations "such as those with heart problems, asthma, the elderly, the very young and the homeless."[401] Moreover, climate change is expected to play a role in worsening air quality problems that already impact human health through climate-induced increases in ozone and particulate matter levels.[402] Again, the vulnerable populations are expected to be impacted the most. Additionally,

[399] UNEP Report, Figure 3 at 12.
[400] EPA, *Climate Change, Health and Environmental Effects* (available at http://www.epa.gov/climatechange/effects/health.html) (last viewed Nov. 9, 2011)
[401] *Id*.
[402] *Id*.

the risk of contracting infectious diseases that are sensitive to climate, from malaria and yellow fever to tick-born Lyme disease, may increase with climate change.[403]

By failing to regulate methane, EPA is ignoring the recommendations of the Secretary of Energy's Advisory Board studying shale gas production. The Board recommended that regulators "expand immediately" efforts to reduce methane emissions using proven technologies.[404] The Government Accountability Office also recognized that requiring the oil and gas industry to control methane has numerous benefits, including (1) decreased greenhouse gas emissions, (2) economic benefits the industry by keeping more natural gas in the system for sale, and (3) for oil and gas development on federal lands, increased royalty payments to the federal government.[405]

B. EPA Must Regulate Particular Matter (PM)

EPA's proposed rule also fails to establish limits on particulate matter pollution from oil and gas development. Particulate matter is a "criteria pollutant" known to endanger public health and welfare. As discussed above, EPA has long evaluated whether it is "appropriate" to revise new source performance standards to include new pollutants based on (1) the amount of emissions from that source category, and (2) the availability of demonstrated control measures.[406] Both factors dictate regulation with respect to particulate matter from oil and gas development.[407] Yet, EPA does not even offer a rationale for failing to regulate this pollutant.

The first factor dictates regulation because oil and gas development is a major source of particulate matter. Particulate matter is produced during every phase of a drilling project. During road and well pad construction, particulate matter is generated by "equipment producing fugitive dust while moving and leveling earth" and by "vehicles generating fugitive dust on access roads."[408] Wind also kicks up particulate matter from

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[403] *Id.*
[404] SEAB Interim 90-Day Report, at 2.
[405] Government Accountability Office, "Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions," *Report to the Honorable Jeff Bingaman, Ranking Minority Member, Committee on Energy and Natural Resources, U.S. Senate*, July 14, 2004, attached hereto as Exhibit 135.
[406] *See, e.g.*, *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n.27.
[407] Section 111 applies broadly to categories of stationary sources including "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3). As the D.C. Circuit has recognized, this may include emissions from roads that are "constituent parts" of a stationary source. *See Ala. Power Co. v. Costle*, 606 F.2d 1068, 1079 (D.C. Cir. 1979), *superseded by Ala. Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979), attached hereto as Exhibit 136. In this case, EPA has defined the oil and natural gas sector broadly to include all "operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas." 76 Fed. Reg. at 52,744. Particulate matter pollution from construction of roads and well pads and vehicle trips necessary to drill for oil and natural gas and produce and distribute natural gas are encompassed within this definition.
[408] West Tavaputs FEIS at 4-16 to 4-17; *see also* BLM, *Revised Near-Field Air Quality Technical Support Document for the GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental*

well pads, dirt roads, and other disturbed areas susceptible to erosion.[409] Drilling and completion activities and subsequent well operations also require significant vehicle traffic, which generates additional particulate matter.[410] For example, trucks are necessary to transport fracking fluids, produced condensate, and water from storage tanks.[411] A 2008 study by the Utah Department of Transportation ("UDOT") estimated a range of 375 to 1,375 truck trips per well, depending on the depth of the well and its location.[412] That translated to 7,585 truck trips per day in the Uinta Basin during 2005-2006.[413] Similarly, in 2006, BLM predicted 851 round-trip truck trips for drilling and operation of each of the 3,100 wells approved by the Jonah Infill Drilling Project in Wyoming.[414]

Construction of wells and roads and vehicle traffic leads to considerable particulate matter pollution. For example, BLM estimates that natural gas operations on the West Tavaputs Plateau will generate more than 8,000 tons of fugitive dust each year from construction, drilling, and development activities and more than more than 1,800 tons each year from operations activities.[415] For the Gasco Energy Inc. Project in the Uinta Basin in Utah BLM estimates emissions of more than 4,000 tons of particulate matter each year.[416] In fact, road traffic associated with the extensive oil and gas development in Uinta County, Utah is expected to push PM_{10} concentrations to 99.7% of the NAAQS standard.[417]

The second factor relevant to EPA's determination whether to establish a standard of performance for particulate matter is also met because there are numerous methods

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Impact Statement, at 9, 17 (Apr. 2010) ("GASCO TSD") ("The major pollutant associated with development activities would be PM_{10} and $PM_{2.5}$ generated by earth-moving and traffic activities."), attached hereto as Exhibit 137; BLM, *Final Supplemental Environmental Impact Statement for the Pinedale Anticline Oil & Gas Exploration & Development Project*, at 4-74 (June 2008) ("Pinedale Anticline SEIS") (noting that particulate matter pollution would be produced by earthmoving equipment and vehicle traffic fugitive dust)

[409] *See, e.g.*, *Air Quality Impact Analysis Technical Support Document for the Pinedale Anticline SEIS*, at 9-11 (June 2008) (noting that substantial PM_{10} and $PM_{2.5}$ emissions would occur from construction of well pads and roads, traffic, and wind erosion)

[410] *See, e.g.*, *West Tavaputs FEIS* at 4-16 to 4-17.

[411] *See, e.g.*, *id.*

[412] *See* ENVIRON, *Oil and Gas Mobile Source Emissions Pilot Study: Background Research Report*, at 3-7 (June 2010) ("ENVIRON Report") (reviewing and summarizing UDOT's 2008 study, *Highway Freight Traffic Associated with Development of Oil and Gas Wells*), attached hereto as Exhibit 138

[413] *Id.* at 7.

[414] *Id.* at 19 (summarizing BLM's 2006 Jonah Infill Drilling Project Environmental Impact Statement).

[415] *See Near-Field Air Quality Technical Support Document for the West Tavaputs EIS*, at 44, 70 ("West Tavaputs TSD"), attached hereto as Exhibit 139.

[416] *GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement*, at 4-7 (Oct. 2010) ("GASCO DEIS"); *see also* ENVIRON Report, at 19 (noting that for the Jonah Infill Drilling Project BLM predicted nearly 4,000 pounds of fugitive PM_{10} per well from the unpaved road traffic necessary just for well completion testing); *id.* at 35 (noting that for drilling in the Little Snake Resource Management Area in Colorado BLM predicted tens of thousands of pounds of particulate matter from the traffic associated with each well pad or project).

[417] *See GASCO DEIS* at 4-27.

available to significantly reduce fugitive dust emissions. For example, application of water or other dust suppressants limits the amount of fugitive dust produced during construction and by vehicle traffic.[418] Watering haul roads can reduce particulate matter emissions by up to 95% during the first half hour after watering and by 74% during the three-to-four hours following watering.[419] Speed and traffic restrictions can also reduce particulate matter pollution from oil and gas vehicles.[420] Other control methods include minimizing road networks by clustering development, and designing and constructing roads with surface materials, drainage, and other characteristics to reduce erosion and sources of fugitive dust.[421] Prompt reclamation and vegetative surfacing of disturbed areas can further limit sources of fugitive dust.[422]

Given the significant amounts of particulate pollution from various stages of oil and gas development and the controls available to limit that pollution, the EPA must promulgate a new source performance standard pursuant to Section 111. EPA has established methods for estimating particulate matter emissions associated with oil and gas development, and could set control efficiencies for those emissions.[423] At a minimum, EPA must establish work practice standards that "reflect the best technological system of continuous emission reduction . . . adequately demonstrated."[424] For example, work practice standards could include requirements for operators to prepare a fugitive dust plan and mandate available control methods for the construction, use, and maintenance

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[418] *See* W.R. Reed & J.A. Organiscak, *Haul Road Dust Control: Fugitive Dust Characteristics from Surface Mine Haul Roads and Methods of Control*, at 4 (Oct. 2007) ("The use of water on haul roads is the most common dust control method used."), attached hereto as Exhibit 140; *see also* EPA, *AP-42: Compilation of Air Pollutant Emission Factors*, Ch. 13.2.2 at 10 (Nov. 2006) ("EPA AP-42") (wet suppression and other forms of surface treatments "increase[] the moisture content, which conglomerates particles and reduces their likelihood to become suspended when vehicles pass over the surface"), attached hereto as Exhibit 141; BLM, *Atlantic Rim Natural Gas Development Project Record of Decision*, at B-5 to B-6 (Mar. 2007) ("Atlantic Rim ROD") (operators required to apply water for dust abatement), attached hereto as Exhibit 142.

[419] *See* Reed & Organiscak, at 4.

[420] *See* EPA AP-42, Ch. 13.2.2 at 8 (vehicle restrictions to control fugitive dust include "lower[ing] the mean vehicle speed"); BLM, *Jonah Infill Drilling Project Record of Decision*, at B-16 (2006) ("Jonah Infill ROD") (requiring contractors and employees to obey speed limits, in part, to reduce fugitive dust concerns), attached hereto as Exhibit 143.

[421] *See, e.g.*, *Jonah Infill ROD* at B-14, B-16 (operators to conduct transportation planning "to identify the minimum road network necessary" and centralize infrastructure and operations); *Atlantic Rim ROD* at B-5 to B-6 (operators to control fugitive dust by "us[ing] appropriate road design including shape, drainage, and surface material to project road bed from being eroded"); AP-42, Ch. 13.2.2 at 10 (describing surface improvements that permanently alter the road surface to reduce fugitive dust emissions).

[422] *See, e.g.*, *Jonah Infill ROD* at B-17 (operators to expeditiously "establish plant cover" for disturbed areas).

[423] *See, e.g.,* AP-42, Ch. 13.2.2 at 4 (EPA equation for estimating fugitive dust emissions per vehicle mile travelled on unpaved surfaces based on surface material silt and moisture content, and mean vehicle weight and speed); BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Record of Decision*, Att. 2 at 36 (July 2010) (condition of approval requiring a minimum of 50% control efficiency for particulate matter from well pad and road construction).

[424] *See* 42 U.S.C. § 7411(h)(1).

of all access roads and well pads.[425] Notably, any standard for application of chemical dust suppressants would require the EPA to assess associated "non-air quality health and environmental impact[s]."[426]

C. EPA Must Regulate Hydrogen Sulfide (H_2S)

Hydrogen sulfide (H_2S) is an extremely dangerous air pollutant which is emitted in significant quantities from the oil and gas industry. Although EPA has issued other Section 111 standards controlling H_2S, and control technologies are available to manage its emissions, EPA has failed to include H_2S in its proposed NSPS, or even to discuss the matter. It must correct this error.

1. Background on H_2S Exposure and Toxicity

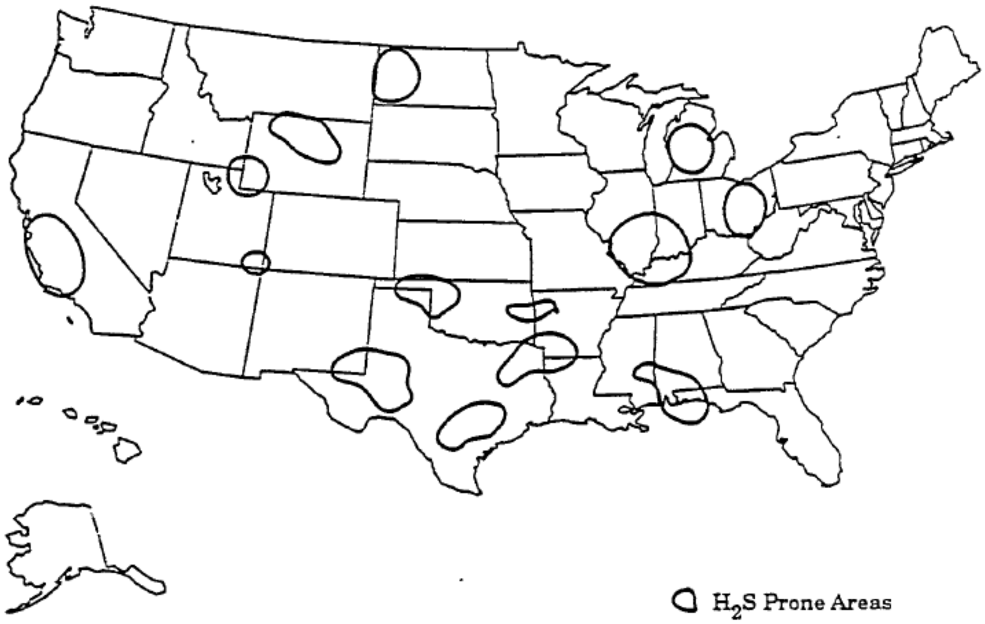
According to EPA, "H_2S is the most common impurity in hydrocarbon gases," and there are at least "14 major H_2S prone areas found in 20 states," including some fields where H_2S is 42% (by volume) of the gas produced.[427] The problem is national in scope, as this the figure below, taken from EPA's own report, demonstrates:

Figure 6

[425] *See, e.g.*, 74 Fed. Reg. 25,312-13 (May 27, 2009) (proposing work-practice standards for roads within coal-preparation operations, including a requirement for "fugitive dust plan[s]" that "require the owner/operator to pave the roads, wet the road surface, sweep up excess coal dust, or install tire washes to remove entrained dust to control PM emissions").

[426] 42 U.S.C. § 7411(h)(1). EPA's own internal report on chemical dust suppressants identifies several potential impacts, such as impacts to surface and groundwater quality, soil contamination, and toxicity to humans. Thomas Piechota et al., *Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach,"* at v (2002), attached hereto as Exhibit 144. The report warns that chemical suppressants "should be avoided near sensitive environments, near water bodies and fractured rock, in areas with a shallow groundwater table, and other areas where water could quickly reach the saturation zone" and that "[s]ite specific characteristics should be considered when approving the use of dust suppressants." *Id.* at 17.

[427] *EPA Hydrogen Sulfide Report* at ii.



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

"Between 15 and 25 percent of natural gas in the U.S. may contain hydrogen sulfide."[428] There is substantial overlap between H_2S-prone areas and active oil and gas plays, meaning, according to EPA, that, with hundreds of thousands of wells at least potentially implicated in H_2S emissions, "the potential for routine H_2S emissions is significant."[429]

This potential is extremely concerning because hydrogen sulfide is toxic even at very low concentrations. The Agency for Toxic Substances and Disease Registry (ATSDR) has established a "minimal risk level" (MRL) – an "estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects" – of 0.07 ppm for acute inhalation exposure to H_2S. ATSDR's intermediate-duration inhalation MRL is 0.02 ppm. EPA, similarly, calculated a chronic reference concentration (RfC) – the threshold below which it would not expect deleterious effects over a lifetime of daily exposure – of 0.001 ppm (that is, 1 part per billion, or "ppb") [430] There is substantial evidence that long-term low-level exposure can cause significant community health problems. As one researcher summarized, these long-term effects are substantial, and are particularly severe in children:

[428] Skrtic Report at 6 (May 2006).
[429] EPA Hydrogen Sulfide Report at III-35.
[430] ATSDR, *Toxicological Profile for Hydrogen Sulfide* at 14, 153 (2006), attached hereto as Exhibit 145.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H2S (with peaks of 100 ppb), 4 ppb, dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H2S from crude oil desulfurization…..

In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H3CSH) were estimate to be 8 μg/m3 (6 ppb) and 2 - 5 μg/m3 (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 μg/m3 (71 ppb) and 50 μg/m3 (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical

> significance…. In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.[431]

The oil and gas industry offers ample opportunities for such exposures, as EPA explained in its 1993 study of its H_2S emissions:

> In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline), and refining. . . . Potential sources of emissions include flares/vapor incinerators, heater-treaters (an oil/water/gas separation device), storage tanks, equipment (valves, flanges, etc.), and both active and abandoned wells.[432]

Although direct monitoring data of H_2S emissions around oil and gas extraction sources is limited, the data that does exist suggest that these sources are substantial. North Dakota, for instance, reported 3,300 violations of an odor-based H_2S ambient air quality standard around wells in that state, likely due to incomplete combustion of H_2S in wellhead flares.[433] Community monitoring in 2011 around gas wells in the Four Corners region of New Mexico and Colorado, likewise detected H_2S in one sample at levels 185 times safe levels.[434]

2. EPA Must Regulate H_2S Under Sections 112 of the Clean Air Act, or, at the very least, Section 111

In view of these risks, EPA must use its Clean Air Act authority to control H_2S emissions from the oil and gas industry.

At present, EPA makes only limited use of that authority. Although H_2S is controlled from major sources under the Prevention of Significant Deterioration program, the oil and gas industry is otherwise largely regulated only to prevent large-scale, emergency releases of H_2S, under Section 112(r) of the Clean Air Act, 42 U.S.C. § 7412(r). This provision focuses on efforts to "prevent the accidental release" of H_2S, and is not a substitute for baseline technological standards, applicable to all sources in the industry, and designed to prevent *ambient*, and long-term exposures to lower levels of this pollutant.

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[431] James Collins & David Lewis, Report to CARB, *Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protection of Children* (Sept. 1, 2000).
[432] *EPA Hydrogen Sulfide Report* at ii; *see also id.* at II-5 – II-11 (listing sources).
[433] *Id. at* III-35.
[434] Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development* at 21

Ultimately, H_2S must be re-listed as a hazardous air pollutant ("HAP") under Section 112 of the Act, and controlled under its standards. [435] Several of the commenting groups have so petitioned EPA, and EPA staff has independently recommended that result, writing that:

- [The EPA OAQPS] Workgroup recommends listing because:
  - H_2S emission tonnage would rank among highest of HAPs
  - In terms of toxic potency, H_2S would rank in the top third of HAPs
  - Both ambient monitoring and modeled exposures show significant exceedances of health benchmarks, chronic and acute
  - Investigations of multiple complaints have demonstrated adverse health effects associated with exceedances of health benchmarks
  - If listed, H_2S would likely rank among top 6 noncarcinogens in [the National-Scale Air Toxics Assessment]
- In combination, these data suggest a "reasonable" likelihood that H2S presents a threat of adverse human health effects for both chronic and acute exposures, and meets the requirements under 112(b)(2) to list.[436]

To date, EPA has not taken action on either this recommendation or upon the petitions before it. In the absence of such action, it is appropriate, and, indeed, necessary, for EPA to control H_2S under the Section 111 program, which, though not as well-suited as Section 112 for the task, is available and can be used immediately. By accepting as much, we of course do not abandon our continued view that Section 112 regulation is ultimately necessary.

H_2S meets both "appropriateness" criteria under Section 111. First, as described above, it is emitted in substantial quantities from the oil and gas industry, in fields across the country.[437] Second, control technologies are readily available, and are in use in the oil and gas industry. Vendors offer, for instance, membrane-based removal systems,[438] a

[435] Hydrogen sulfide was removed from the section 112 list, without explanation, by Congress after significant industry pressure; its removal continues to put public health and welfare at unacceptable risk. Nothing prevent EPA from correcting this problem by re-listing hydrogen sulfide.

[436] EPA OAQPS Sector Based Assessment Group, *Should Hydrogen Sulfide be a HAP?* at 23 (Sept. 2007), attached hereto as Exhibit 146.

[437] Significantly, in this regard, state regulations are not uniformly or adequately limiting these emissions. As EPA staff recently summarized, state rules are highly variable, and many states (including major oil and gas producers like Louisana, and states containing important new plays, like Ohio, lack H_2S standards entirely). *See id.* at 16. Although the presence or absence of state regulation does not bear on EPA's Section 111 regulations, it is notable that exposure risks are going uncontrolled in many regions at both the state and federal levels, and underlines the unreasonableness of EPA's failure to act.

[438] Membrane Technology and Removal, H_2S Removal from Natural Gas: Soursep (vendor offering wellhead bulk removal system), attached hereto as Exhibit 147.

wide range of amine-based removal systems to scavenge H_2S at wells and in tanks,[439] and compounds designed to prevent bacteria from producing H_2S.[440]

EPA moreover has demonstrated that it can regulate H_2S emissions from a wide range of sources under Section 111. EPA has promulgated several NSPSs which control either H_2S or "total reduced sulfur" (a catchall term that includes H_2S) including for pulp and paper mills and petroleum refineries – but not for gas processing plants or oil and gas production. The most significant of these standards are the Subpart J and Ja standards, which control emissions from new and modified petroleum refineries. EPA's sulfur standards bar flaring any fuel gas which contains more than 230 mg/dscm of H_2S, as a sulfur oxide control measure, 40 C.F.R. § 60.104(a)(1), and bars emissions of any gas from Claus sulfur recovery plants which is more than 300 ppm by volume of reduced sulfur compounds or more than 10 ppm H_2S.[441] The standards also require periodic H_2S monitoring.[442] Yet, the NSPS program does not control H_2S from oil and gas sector sources.

It is time for EPA to correct this omission. Because both Section 111 appropriateness factors are met, EPA must propose, and then finalize, H_2S standards covering each H_2S source in the oil and gas sector.

To the extent EPA believes it requires more data to issue such standards, it must issue a Section 114 information collection request gathering data from the industry. This information request is particularly important because much of our information about the industry's emissions is rooted in EPA's 1993 report to Congress on H_2S. That report was drafted long before the shale gas boom saw the industry expand substantially, including into many urban and heavily-settled semi-rural areas. Now, wells are being built throughout the Dallas-Forth Worth area, for instance, as well as in and around cities in Pennsylvania. Properly assessing the health impacts of this increasing interweaving of oil and gas development with dense settlement is critical to accurately understanding H_2S exposure risks. EPA must properly assess these risks, and, in view of these changed circumstances, cannot rely upon its earlier assessments to assert that ambient exposure to H_2S is limited. Without waiving any claim that EPA was required to collect such information in the context of this rulemaking in order to timely complete its review duties, we ask that EPA state, in the final rule, whether and when it will issue such an information collection request.

[439] Weatherford, *Hydrogen Sulfide Control* (vendor offering amine-based removal system), attached hereto as Exhibit 148; Baker Hughes, *White Paper: Hydrogen Sulfide Management: Mitigation Options in Petroleum Refining, Storage, and Transportation* (discussing a wide range of solutions for reducing H_2S formation and venting in tanks), attached hereto as Exhibit 149

[440] Yara United States, *PetroCare* (vendor offering chemical compounds for use in well construction to prevent H_2S formation), attached hereto as Exhibit 150.

[441] 40 C.F.R. § 60.104(a)(2); 40 C.F.R. § 60.102a(f)(1)(ii).

[442] 40 C.F.R. 60.105(f).

D. EPA Must Regulate Nitrogen Oxides (NO_x)

As we discuss above, certain oil- and gas-field combustion sources, including heater-treaters, are major NO_x emissions sources. Heater-treaters, in fact, may become dominant NO_x emissions sources in many regions, because they are so numerous. EPA must regulate this source, and, hence, must regulate this pollutant.

Once again, it is "appropriate" to do so under Section 111. As we discuss above, heater-treaters emit significant amounts of NO_x, and these emissions are controllable. As a result, EPA must include appropriate NO_x regulations in the final rule.

V. EPA MUST REGULATE METHANE AND VOCS FROM EXISTING SOURCES

Although the emissions reductions secured by EPA's proposal are significant, they represent only a relatively small fraction of the industry's total air pollution, because they do not address the extensive network of existing sources. As a result, as we note above, EPA is capturing only about 26% of the total methane emissions from the industry, and is likely capturing roughly similar percentages of the VOC emissions.[443] Although the proposed NSPS achieves significant VOC reductions from new and modified sources, it fails to control emissions from non-well existing sources, aside from refractured wells, even though these emissions are substantial. EPA must issue standards under section 111(d) of the Clean Air Act to control these emissions.

Unless these existing sources are regulated, the industry will continue to be a major source of significant air pollution for years to come. For this reason, the Secretary of Energy's Advisory Board Shale Gas Production Subcommittee, charged by the President with developing recommendations to control the industry's impacts, directly called on EPA to regulate existing sources in this rulemaking, writing:

> On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. *However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.*[444]

[443] *See* 76 Fed. Reg. at 52,792.

[444] Shale Gas Production Subcommittee Second 90-Day Report (Nov. 18, 2011) at 5 (emphasis added), attached hereto as Exhibit 151.

EPA must correct this crucial gap. It is required to do so by statute, for both methane and VOC sources, as we explain below. Because much pollution from existing sources can be controlled using variations of the same methods EPA has already proposed for new sources in this rulemaking, such existing source standards can be developed and implemented quickly. After setting out EPA's legal obligations, we describe how such standards can and must be designed.[445]

A. EPA Must Regulate Existing Sources of Methane

We have already described why EPA must regulate methane from new and modified sources under Section 111(b): It is an abundant (indeed, the most abundant) pollutant from the oil and gas industry, and is readily controlled with available technology. Once EPA promulgates such new and modified source standards, it will be required to control existing sources as well, under Section 111(d) of the Act.

Section 111(d) of the Act provides that EPA "shall prescribe regulations" which establish a process, mirroring that for State Implementation Plans pursuant to section 110, under which states establish standards of performance for existing sources that emit certain pollutants.[446] These pollutants, referred to as "designated pollutants," 40 C.F.R. § 60.21(a) include:

> Any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[447]

Methane will be such a "designated pollutant" as soon as EPA issues 111(b) standards controlling it. This is because methane is, first, not a criteria pollutant (that is, it is not "on a list published under section 7408(a)" and EPA has not issued an air quality standard for it). Nor is methane a critical air pollutant "regulated under section 7412."[448] As a result, once "a standard of performance under this section" is

[445] We note the proposal does apply to some existing sources through its modification provisions. Specifically, we applaud EPA's proposal to define the completion and recompletion of a hydraulically fractured gas well as a modification. It appears from the preamble that other existing sources, including pneumatic controllers and centrifugal compressors, are also subject to the new source performance standards, in a manner of speaking, in that the NSPS dictates how they must be replaced. 76 Fed. Reg. at 52738, 52761-62. We agree that replacement of an existing source constitutes new construction and therefore requires compliance with the NSPS. The final rule language must clarify that replacement of any and all affected facilities triggers compliance with the NSPS.
[446] 42 U.S.C. § 7411(d)(1).
[447] 42 U.S.C. § 7411(d)(1).
[448] Although the statute refers to pollutants "emitted from a source category which is regulated under section 7412," EPA has made clear in its rules that this restriction on 111(d) applicability applies to

promulgated for the industry, regulating methane, methane will also be subject to Section 111(d) regulation.

Such regulation is implemented via a state-implementation-plan like process "under which each State shall submit to the Administrator a plan which establishes standards of performance for any existing source" of a designated air pollutant.[449] To speed this process, EPA sets forth standards of performance for these pollutants covering existing sources in "emission guidelines," which the states must then adopt.[450] Emission guidelines specify how the states shall reduce air pollution from existing sources that emit certain air pollutants to which a standard of performance would apply if such existing source were a new source.[451]

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology" and the "Best System of Emissions Reduction."[452] Emission guidelines can be tailored to the remaining useful life, of existing sources, as well as other relevant factors.[453] EPA "shall" issue such emissions guidelines for pollutants that are neither hazardous air pollutants listed under section 112 nor criteria pollutants listed under section 108.[454]

This process moves forward once EPA has promulgated Section 111(b) standards. EPA rules provide that "*[c]oncurrently* upon or after proposal of standards of performance for the control of a designated pollutant [from sources subject to an NSPS]," EPA "*will* publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities [existing sources]," and "a final guideline document *will be published*" "*upon or after*" promulgation of standards of performance for new sources.[455]

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pollutants listed under Section 112, not every pollutant emitted from a Section 112 source category (as some of these pollutants may not be listed HAPs, but will still warrant control under other programs).

[449] 42 U.S.C. § 7411(d)(1).

[450] *See* 40 C.F.R. §§ 60.21(e) and 60.22.

[451] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.21(b) (defining facilities to which emission guidelines apply as those "which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility").

[452] 40 C.F.R. § 60.22(b)(5) (providing that guideline documents "will" include "an emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities…"). *See also* 40 C.F.R. § 60.21(e) ("Emission guideline means a guideline set forth in subpart C of this part, or in a final guideline document published under § 60.22(a), 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 such reduction) the Administrator determines has been adequately demonstrated for designated facilities.")). Of course, in situations where EPA has set a section 111(h) BTSER standard, existing source regulations must parallel this standard as well.

[453] 42 U.S.C. § 7411(d)(1); 40 C.F.R. § 60.22(b) (describing content of emission guidelines).

[454] *See* 42 U.S.C. § 7411(d)(1).

[455] 40 C.F.R. § 60.22(a) (emphases added).

Thus, EPA regulation of new and modified sources will trigger regulation of existing sources. This process will take time. Once a guideline document has been published, the states generally have nine months to submit their plans,[456] and the plans themselves may not become effective immediately for all sources. The longer EPA delays even proposing *new* source standards, the longer it will take to complete the existing source process, during which time approximately three-quarters of the industry's methane emissions will continue to go uncontrolled. EPA therefore must begin the process as soon as possible in order to timely address this major emissions source.

B. EPA Must Regulate Existing Sources of VOCs

Like methane, VOCs are "designated pollutants" for Section 111(d) purposes and EPA must promulgate existing source standards for them.

VOCs are designated pollutants because they are neither criteria pollutants nor hazardous air pollutants. For NSPS purposes, "Volatile Organic Compound" means, simply, "any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an alternative method, or which is determined by procedures specified under any subpart."[457] There are no 42 U.S.C. § 7408 criteria for VOCs so defined, and VOCs are not listed as section 112 HAPs.[458] Moreover, when EPA finalizes its current proposal, VOCs will be "subject to a standard of performance for new stationary sources" in the oil and gas industry.[459] As such, the plain language of the statute, and of EPA's implementing regulations,[460] renders VOCs designated pollutants.

Thus, once EPA finalizes its 111(b) standards, it must immediately move on to proposing and finalizing 111(d) standards for existing VOC sources.[461] Although the regulations provide that EPA must act "concurrently or thereafter," we urge EPA to offer proposed guidelines simultaneously with its final new source standards, to ensure that the process to control this major pollution source moves forward rapidly, and to provide the industry with a clear regulatory calendar.

Such progress is particularly important because existing facilities are such significant VOC sources. Although new and modified VOC sources emit a total of 2.24 million tons of VOC per year,[462] and, according to EPA, the proposed NSPS and NESHAP, acting

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[456] 40 C.F.R. § 60.23
[457] 40 C.F.R. § 60.2; *see also* Proposed 40 C.F.R. § 60.5430 (adopting the definitions in § 60.2 and in Subpart VVa); 40 C.F.R. § 60.481a (Subpart VVa, adopting the § 60.2 definition).
[458] *See* 42 U.S.C. § 7412(b)(1) (HAP list)
[459] See 40 C.F.R. § 60.21(a).
[460] *See* 40 C.F.R. § 60.21(a),
[461] 40 C.F.R. § 60.22(a).
[462] RIA at 3-1.

together, will reduce VOC emissions from these sources by 540,000 tons of VOC or more in 2015,[463] but existing sources account for a substantial portion of the remaining VOC inventory. While EPA does not include an estimate of the total amount of emissions from existing sources in the proposed rulemaking, estimates from others demonstrate such emissions are substantial. As Table 2 demonstrates, VOCs from existing sources in five basins in the Intermountain West are projected to equal 259,051 tons in 2012.[464] Without regulation to reduce emissions from existing equipment, these emissions will continue for many years.

Table 2

Oil & gas emissions source	**Denver-Julesburg basin**		**Uinta basin**		**Piceance basin**		**North San Juan basin**		**South San Juan basin**		**Wind River basin**	
VOC	2006	2010	2006	2012	2006	2012	2006	2012	2006	2012	2006	2012
Condensate tanks	53,510	53,109	6,195	21,719	3,405	1,895	0	0	3,964	3,790	710	519
Oil tanks	0	0	14,357	20,722	0	0	165	165	2,430	2,359	449	486
Dehydrators	506	332	19,470	30,665	2,929	2,371	14	10	11,372	10,896	1,324	1,010
Well blowdowns	1,744	2,207	292	460	2,172	2,444	0	0	13,145	12,595	2,018	1,861
Fugitives	8,024	10,498	1,910	3,212	1,330	1,871	0	0	4,137	4,631	296	415
Pneumatic devices & pumps	12,381	16,342	23,301	39,404	2,532	3,835	0	0	1,726	1,925	6,351	7,303

In short, if EPA developed standards for existing sources it would achieve substantial health and environmental benefits. It must do so.

We recognize, of course, that VOCs are also treated as ozone precursors, and that ozone is a criteria pollutant, which could not itself be regulated under Section 111(d). Although they are not defined as precursors for NSPS purposes, EPA's regulations governing the Prevention of Significant Deterioration program,[465] and those governing state implementation plans,[466] do so define them. Ozone is generally regulated

[463] 76 Fed. Reg. at 52,791.
[464] Western Regional Air Partnership Phase III *2006 and 2012 Activity Emission Estimates for the Denver-Julesburg, Piceance, Uinta, South San Juan, North San Juan, and Wind River Basins*, available at http://www.wrapair.org/forums/ogwg/PhaseIII_Inventory.html, attached hereto as Exhibit 152.
[465] *See* 40 C.F.R. §§ 51.15(a)(1)(xxxvii)(c)(1), 51.166(b)(49)(i), 52.21(b)(50)(i)(A).
[466] *See* 40 C.F.R. § 51.100(s)

primarily through state implementation plans implementing the National Ambient Air Quality Standards (NAAQS) for ozone, as directed by Section 108 of the Act and by the special ozone regulatory program in subpart 2 of part D of the Act, addressing ozone nonattainment areas.[467]

Although some commenters may argue that this precursor status precludes section 111(d) regulation of VOCs, this is not the case. Initially, as a purely textual matter, the statute simply does not refer to "precursors" to criteria pollutants themselves as included in the Section 111(d) ban. Nor do EPA's implementing regulations. So, to the extent that EPA has any authority to decline regulation of VOCs as 111(d) pollutants, that authority does not arise from section 111(d).

If EPA claims such authority, it could be found only in section 302, which provides that the term "air pollutant":

> [I]ncludes any precursors to the formation of any air pollutant, *to the extent* the Administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used.[468]

Put differently, section 302, if anything, grants EPA the discretion to identify particular precursors and incorporate those substances into the definition of an "air pollutant" for particular regulatory purposes.

EPA has used this discretion previously. In a series of rulemakings implementing the PM 2.5 NAAQS, it explained that it would treat each PM 2.5 precursor distinctly for regulatory purposes because "the Administrator has discretion to identify which pollutants must be classified as precursors for particular regulatory purposes."[469]

Thus, nothing about section 302 obligates EPA to decline to regulate VOCs under section 111(d). On the contrary: section 302 authorizes EPA to identify distinct "particular purpose[s]" in its various regulatory definitions of precursor pollutants. The agency therefore need not treat VOCs the same way for section 111(d) regulation as it does for ozone NAAQS regulation, because in each instance, the regulations "address different aspects of the air pollution problem" caused by VOCs. Specifically, although sections 108 and 182 of the Act requires state implementation plans to include some control of existing sources of VOCs in ozone nonattainment areas, they do not extend to sources in attainment areas, and also do not necessarily reach every important source in each industry source category.[470] Section 111(d), by contrast, can reach existing sources of

[467] *See, e.g.*, 42 U.S.C. § 7511.
[468] 42 U.S.C. § 7602(g).
[469] 73 Fed. Reg. 28,322, 28,326 (May 16, 2008) (final rule on using the PM 2.5 standards in the NSR program), attached hereto as Exhibit 153; 72 Fed. Reg. 20,586, 20,590-91 (Apr. 25, 2007) (Clean Air Fine Particle Implementation Rule, making the same points), attached hereto as Exhibit 154.
[470] *See* 42 U.S.C. § 7511a.

VOC pollution in attainment and in nonattainment areas, and can provide a uniform, clear regulatory standard for actors across the oil and gas industry, which is a major source of VOC pollution.

These distinct statutory purposes and distinct air pollution problems support treatment of VOCs as 111(d) pollutants, even were the plain language of the statute and regulations not so clear. Indeed, it would be unreasonable for EPA *not* to use its discretion to regulate VOCs under section 111(d).[471]

C. EPA Has Used Its 111(d) Authority to Functionally Regulate VOCs and Methane Before

Although EPA has not previously issued section 111(d) standards that explicitly control VOCs, its standards of performance for municipal solid waste landfills are, functionally, 111(d) VOC standards, and provide a useful model here.

Landfills are significant sources of methane, VOCs, and other pollutants. To address existing landfills, EPA promulgated 111(d) control guidelines concurrently with its new source performance standards. These guidelines are based upon a pollutant mixture of "non-methane organic compounds" (NMOC).[472] NMOC is 80% VOC by mass, so NMOC controls are fundamentally VOC controls, which happen to also control some non-VOC pollutants.[473,474] Likewise, though EPA, as a legal matter, excluded methane from regulation as part of "NMOC", methane is co-emitted with NMOC, meaning that NMOC controls reduce methane emissions as well as non-methane organic compounds.[475]

EPA emphasized the benefits of VOC and methane control (along with control of hazardous air pollutants co-emitted with NMOC at existing sources) in its rulemaking. As it explained:

> NMOC includes [VOC], hazardous air pollutants (HAPs), and odorous compounds. VOC emissions contribute to ozone formation which can result in adverse effects

[471] It is true that EPA has once declined to use its 111(d) authority to regulate VOCs in its 2007 NSPS for VOC leaks from synthetic chemical manufacture and refineries (subpts. VV, VVa, GGG, and GGGa), 72 Fed. Reg. 64,680, 64,868 (Nov. 16, 2007), attached hereto as Exhibit 155. It did so without detailed explanation or analysis, however, and is free to change that position by rulemaking here, particularly in view of the industry's extraordinarily high VOC emissions.

[472] 61 Fed. Reg. 9,905, 9,905 (Mar. 12, 1996) (final 111(d) standards); 40 C.F.R. §§ 60.751 & 60.754 (regulatory NMOC definition), attached hereto as Exhibit 156.

[473] *See* 61 Fed. Reg. at 9,912 (stating that NMOC emissions of 50 tpy "correspond[] to a VOC emission rate of 40 tpy.").

[474] See also EPA, Municipal Solid Waste Landfill New Source Performance Standards (NSPS) and Emissions Guidelines (EG)—Questions and Answers (1998) at 19 (explaining that "NMOC is non-methane organic compounds, which include volatile organic compounds (VOC) as well as other organic compounds"), available at http://www.epa.gov/ttnatw01/landfill/landfq%26a.pdf, attached hereto as Exhibit 157.

[475] Of course, as discussed above, we do not agree with EPA's failure to regulate methane here.

> to human health and vegetation. Ozone can penetrate into different regions of the respiratory tract and be absorbed through the respiratory system. The health effects of exposure to HAPs can include cancer, respiratory irritation, and damage to the nervous system. Methane emissions contribute to global climate change and can result in fires or explosions when they accumulate in structure on or off the landfill site . . . . Today's rules will serve to significantly reduce these potential problems with [landfill gas] emissions.[476]

EPA further specified the benefits of reducing existing source emissions of VOCs and methane in its proposed rule, listing five benefits: (1) reduced ozone formation; (2) incidental control of HAPs; (3) managing the "well-documented danger of fires and explosions"; (4) controlling unpleasant odors; and (5) reducing the severity of global climate change.[477]

To address these harms, EPA issued 111(d) standards embracing all large existing landfills,[478] requiring them to install emissions control systems that collect and destroy escaping landfill gas.[479] These standards, which covered hundreds of existing landfills,[480] halved NMOC emissions from those sources, and reduced methane emissions by about 40%.[481]

EPA can and must take several lessons from this experience:

<u>First</u>, as discussed above, EPA has authority to set and direct section 111(d) standards for VOCs although VOCs are precursors of the 108 pollutant ozone. VOCs are an important precursor to ozone, a listed 108 pollutant. Without 111(d) regulation, not all important existing sources of these precursor pollutants will be subject to emissions controls. For instance, although section 182 of the Act requires state implementation plans to include some control of existing sources in ozone nonattainment areas, it does not extend to sources in attainment areas, and also does not necessarily reach every important source in each industry source category.[482] Section 111(d) is thus an important adjunct to controlling these existing sources. In the landfill standard, EPA took this view. Although EPA opted to regulate VOCs as part of NMOC, this distinction is not practically important, whatever its legal significance: NMOC controls regulate VOCs, and

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[476] 61 Fed. Reg. at 9,905-06. *See also* 56 Fed. Reg. 24,468 (May 30, 1991) (proposed rule), attached hereto as Exhibit 158.
[477] *Id.* at 24,472-75.
[478] We do not take a position here as to the appropriateness of EPA's emissions threshold decisions for landfills.
[479] 61 Fed. Reg. at 9,907-9,908.
[480] *Id.* at 9,914.
[481] *Id.* at 9,908-9.
[482] *See* 42 U.S.C. § 7511a.

the regulation is founded on these benefits.[483] EPA could just as readily have regulated VOCs alone.

Second, section 111(d) controls may incidentally control hazardous air pollutants, or criteria pollutants. Although section 111(d) may not be relied on to *satisfy* section 112 requirements due to the differing statutory requirements between the two programs, regulations targeted at non-HAPs may produce important HAP co-benefits, but the existence of those co-benefits does not eliminate the requirement to directly regulate the pollutant in question. Thus, though landfill gas contains several HAPs,[484] and regulating NMOC would help reduce their emissions, EPA did not view this benefit as an impediment to section 111(d) regulation. Instead, it emphasized HAP control as an important additional benefit to section 111(d) control.[485]

Third, section 111(d) regulations for existing sources can be designed to rapidly produce significant emissions reductions. The landfill standards were designed to reduce NMOC emissions by 7 million megagrams in the first four years of their operation.[486]

Oil and gas production sources offer similar opportunities. Once again, EPA has the opportunity of regulating a class of existing sources whose emissions are cumulatively large. Existing source controls would produce all five of the benefits EPA identified for its earlier landfill section 111(d) rules, as controlling VOCs would reduce VOC and methane emissions, along with some HAP emissions.[487] And, once again, existing sources can readily adopt cost-effective controls (and, in fact, already do so as set forth elsewhere in these comments). We outline some of these potential controls below.

D. Design Approaches for a Section 111(d) Standard for VOC and Methane

Like standards of performance for new sources, emission guidelines must reflect "Best Demonstrated Technology."[488] New source standards are the starting point for existing source standards, but those rules may be modified to "take into account the remaining useful life of the existing sources to which such standard applies."[489]

Many of the standards EPA has proposed for new sources can be readily and cost-effectively applied to existing sources without losing rigor, as demonstrated by the standards in place in Wyoming and Colorado for storage vessels, gas processing plants

[483] 61 Fed. Reg. at 9,906.
[484] 56 Fed. Reg. at 24,474
[485] *Id.*
[486] *Id.* at 9,908.
[487] *See* RIA at 4-18 – 4-35.
[488] 40 C.F.R. § 60.22(b)(5).
[489] 42 U.S.C. § 7411(d)(1); *see also* 40 C.F.R. § 60.24(c) (providing that 111(d) standards generally "shall be no less stringent than the corresponding emission" standards for new sources).

and pneumatic devices, described above.[490] Similar approaches could be used to control methane and VOCs for each facility type, so we sketch these design principles for both pollutants, recognizing that separate regulations must be promulgated for each pollutant in order to fully regulate these sources. We discuss each facility type in turn.

Notably, although the same general *technology* can control methane and VOCs, allowing us to describe these standards jointly, these technologies will not necessarily be *applied* across the sector – and nor can their use be enforced -- unless EPA issues section 111(d) standards for both VOCs and methane. This gap occurs, as we have explained above, because VOCs and methane are not co-emitted in equal proportions across the sector. Instead, the proportion of methane to VOC emissions grows steadily as gas moves from the wellhead to the distribution sector, meaning that VOC standards are unlikely to operate rigorously further down the production chain, and that, as a result, methane-specific controls are needed to fully achieve the existing source benefits we describe below.

1. Standards for Existing Pneumatic Devices

Pneumatic devices in the production sector are responsible for 17% of production sector emissions emitting 67 Bcf of methane annually. Pneumatics in the transmission sector emit another 12 Bcf.[491] Because methane is co-emitted with VOCs, these controllers are also significant VOC sources. According to EPA, a single year's worth of new bleed devices (about 17,000 controllers) will emit 32,739 tons per year of VOCs, along with 117,766 tons of methane.[492] New controllers, however, are only a small fraction of the existing population of controllers. The latest EPA GHG Inventory estimates that 564,842 pneumatic controllers exist in the production, processing, transmission and storage sectors as of 2009.[493] Using EPA's estimates of the percentage of existing controllers that are high versus low or no-bleed, approximately 243,976 and 27,481 high-bleed controllers existed in 2009 in the production and transmission/storage sectors respectively.[494] This existing population emits 556,373 tons of VOCs annually. Applying EPA's assumption that 80% of high-bleed devices can be replaced with low or no-bleed devices, a 111(d) standard that requires replacement of high-bleed controllers would

[490] Elsewhere in these comments, we discuss ways that the new source standards should be improved. We expect that corresponding improvements would also appear in the proposed existing source standards.
[491] Copeland & Williams Report at 32-33.
[492] EPA, TSD at 5-10.
[493] EPA, *Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011*, Table A-120, p. A-149, http://epa.gov/climatechange/emissions/usinventoryreport.html. This is a more recent estimate than that provided in the TSD which estimates the pneumatic controller population for 2004 to be 498,000. TSD, 5-1. We refer here to the estimate of existing source population contained in the Inventory because it is more recent and also because it breaks out the number of controllers per industry segment (i.e.: production, processing and transmission).
[494] EPA estimates the number of bleed devices in the production and transmission sectors to be 51% and 32%, respectively. TSD at 5-7

thenceforth annually remove approximately 1,288,195 tons of methane and 351,326 tons of VOCs from the atmosphere from the production sector and 6,508 tons of methane and 1,759 tons of VOCs from the transmission/storage sector.[495] Since these figures represent the existing population as of 2009, the actual pollution reductions are likely much greater since oil and gas production has increased since 2009. EPA could, therefore, achieve significant benefits by applying controls to existing pneumatics.

The proposed new source controls provide a useful model. As proposed, the rules define each affected facility as a "single pneumatic controller."[496] As a result, each new controller must meet the performance standards, which generally require no-bleed valves at processing plants, and low-bleed controllers elsewhere.[497] As a result, replaced controllers must be no or low-bleed.[498] Given enough time, as old controllers wear out, this requirement will therefore gradually cause the entire population of controllers to turn over.

But without 111(d) standards, replacing the existing collection of controllers will take a great deal of time. EPA estimates pneumatic controllers have a ten-year expected lifetime for amortization purposes, but controllers may last even longer in practice – and EPA has developed no data showing otherwise.[499] Existing source standards could usefully accelerate replacement of polluting controllers.

Therefore EPA must set emissions standards which drive operators to timely replace their existing controllers with no-bleed controllers or (if no-bleed controllers cannot be used), low-bleed controllers in a timely fashion. These replacements are highly likely to be cost-effective. EPA determined that, thanks to increased natural gas capture from replacement devices, its new source controller standards will generate annualized net savings of $1,159 per controller in the production sector, and costs of only $23 per controller in the transmission and storage sector.[500] Because these estimates *already* include the costs of replacing controllers at existing sources where sources voluntarily undertake replacement, EPA can be sure that such replacements are both feasible and cost-effective.

Notably, Colorado and Wyoming have reached similar conclusions regarding the efficacy and cost-effectiveness of replacing high-bleed devices with low or no-bleed ones. Colorado requires that, "when new, replaced, or repaired pneumatic devices are

[495] TSD at 5-12 (assuming 80% of high-bleed controllers can be retrofit as low or no-bleed)
[496] Proposed 40 C.F.R. § 60.5365.
[497] Proposed 40 C.F.R. § 60.5390.
[498] *See id.*
[499] TSD at 5-16.
[500] RIA at 3-15. Note that the net positive cost in transmission and storage, in contrast to the negative cost in the production segment, arises because pipeline firms typically do not own the gas conserved with no-bleed or low-bleed controllers (since they do not own the gas in their pipelines). We believe that the industry as a whole, therefore, will save money from installation of less wasteful controllers.

installed, low or no bleed valves must be used, where technically feasible,"[501] and Wyoming requires all new and modified controllers to be low or no-bleed.[502] Moreover, in certain ozone non-attainment areas, Colorado also requires all high-bleed pneumatic controllers to "be replaced or retrofit such that VOC emissions are reduced to an amount equal to or less than a low-bleed pneumatic compressor". Colorado required such replacements within months of the time the regulation was promulgated.[503] Colorado determined that such retrofits were highly cost-effective, resulting in savings of $747 per controller including gas savings.[504]

To be sure: although replacement costs are either negative or very small, there may well be nontrivial labor and logistics costs associated with replacing the entire population of existing controllers on an accelerated schedule. EPA could reflect that logistical challenge by designing the existing source standard around the "remaining useful life" of these devices, staggering or extending a replacement requirement to reflect instrument failure rates and repair frequencies. For instance, an existing source standard might require that all existing controllers be replaced within three years or some other reasonable period, allowing for a manageable compliance period. Alternately, EPA might further calibrate a replacement time period by comparing replacement costs with the cost savings resulting from a new no-bleed or low-bleed controller, and then setting the replacement period at the point at which, on average, savings from a new controller balance out the labor costs of an early replacement. Finally, EPA might simply seek to take advantage of repair visits to existing facilities, and specify that, when a facility is visited for planned maintenance; existing controllers are to be replaced at the same time as other work is to be done.

Whichever of these options EPA ultimately proposes and evaluates, the core concern is the same: The existing fleet of controllers is a significant methane and VOC source. If EPA accelerates the replacement frequency for these devices, the public will capture major emissions benefits –controlling just new devices would reduce VOCs by 90,685 tpy and achieve equally significant methane benefits. Swiftly replacing existing devices will yield far greater reductions.

2. Standards for Existing Compressors

EPA estimates suggest that there are over 12,000 existing reciprocating compressors[505] and 1,400 existing centrifugal compressors.[506] Leaks from these compressors make

[501] Co. Oil and Gas Conserv. Commission Rule 805(b)(2)(E), attached hereto as Exhibit 159.
[502] Wy. Dept. of Envt'l Quality, *Oil and Gas Production Facilities* (Mar. 2010) at 10, attached hereto as Exhibit 160.
[503] Co. Department of Public Health and Environment Regulation 7, XVIII.C.2 (promulgated Dec. 12, 2008. High-bleed controllers had until May 1, 2009 to comply), attached hereto as Exhibit 161.
[504] Revised final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-only Revisions to the Air Quality Control Commission's Reg. Number 7 (Dec. 11, 2008), attached hereto as Exhibit 162.
[505] TSD, 6-8, 9.

them dominant emissions sources,[507] emitting on the order of 105 Bcf of methane across the production, processing, and transmission and storage sectors.[508] Compressor VOC emissions are, unsurprisingly, also substantial. EPA states that just the *newly installed* compressors (not including compressors installed to replace existing compressors) now covered by the proposed standards would emit 2,798 tons of VOCs annually in the absence of the proposed standard.[509] Emissions from existing reciprocating compressors in the processing and transmission sectors alone equal approximately 37,000 Tpy.[510] EPA has low-cost options to extend controls to these existing sources. Emission guidelines that require replacement of rod-packing from existing compressors in the processing sector would remove approximately 25,258 tons of VOCs and 90,694 tons of methane. Similar reductions can be achieved from compressors in the transmission and storage sector, namely 5,010 tons of VOCs and 181289 tons of methane. These reductions, which total 30,268 tons of VOC and 271,983 tons of methane, do not include reductions from the 34,930 compressors located at wellheads, gathering and boosting stations. Emissions reductions from these sources are not estimated since EPA's GHG Inventory does not disaggregate wellhead compressors from those located at gathering and boosting stations yet EPA applies different emission reductions to each type of compressor.[511]

Beginning with reciprocating compressors, which are by far the more common compressor type, EPA can directly extend its new source performance standard. That standard would require operators to replace reciprocating compressor rod-packing "before the compressor has operated for 26,000 hours."[512] This simple maintenance standard, applied at new sources, saves 1,759 tons per year of VOCs,[513] and does so at a low cost. EPA estimates cost per ton of VOC controlled (with saved natural gas offsets) at a few thousand dollars or less (including savings in some cases) for gathering, processing, transmission, and storage compressors.[514] Nothing prevents operators from immediately applying an identical maintenance approach to existing compressors, and EPA must so require.

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[506] EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122. EPA does not provide an estimate of the number of existing centrifugal compressors in the TSD.

[507] This emissions source is both under-controlled and under-measured: In 2010, for instance, EPA uprevised its emissions factor for leaks from centrifugal compressor from 0 to 233 metric tons CH_4/year. TSD at 9.

[508] *See* EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011) at Table A-120., p. A-122.

[509] TSD, Table 6-5.

[510] These calculations are based on EPA's baseline VOC emissions for reciprocating compressors in Table 6-3 of the TSD. Note because EPA does not provide estimates of the number of reciprocating compressors at wellheads or in the storage sector, and this information is also not provided in EPA's GHG inventory, we do not here estimate emissions from compressors in these sectors.

[511] See TSD 6-6, noting that the GHG Inventory does not separate wellhead from gathering and boosting compressors and Table 6-6 applying emission reductions to different types of compressors.

[512] Proposed 40 C.F.R. §60.5385.

[513] TSD, Table 6-6.

[514] TSD, Table 6-7.

Centrifugal compressors also offer significant control opportunities. Requiring dry seals for non-wellhead compressors alone, as EPA now proposes for new sources, would reduce VOC emissions by 329 tons per year (this number is low because EPA assumes few new installations of centrifugal compressors each year, and replacements of existing compressors are not included in this figure).[515] Using the estimate of existing centrifugal compressors in the 2009 GHG Inventory, replacement of wet seals with dry on compressors would remove 13, 926 tons per year of VOCs (11,628 from the processing sector and 2298 from the transmission/storage sectors).[516] The resulting savings are substantial: For each ton of VOC avoided, operators recover over $25,405 in avoided natural gas loss and O&M costs annually at transmission and storage compressors, and another $6,892 at processing compressors.[517] The result is millions of dollars in avoided costs each year.[518]

If EPA's emissions standards drove operators to replace wet seals with dry seals at existing compressors, operators would capture far more benefits, as existing centrifugal compressors greatly outnumber new compressors. We therefore recommend that EPA set these standards to drive such replacements in existing compressors.

3. Standards for Existing Storage Vessels

Under the proposed NESHAP, EPA has already proposed a 95% emissions control requirement for new and existing storage vessels at major sources of HAPs.[519] For new storage vessels not covered by the NESHAP, EPA has proposed an NSPS requirement that would apply an identical standard at wellsite storage vessels which have the potential to emit 6 or more tons per year of VOCs, at a cost of $143 per ton of VOCs captured for large vessels.[520,521,522] Combined, these standards cover many tanks, but likely leave a population of existing vessels which are not major HAP sources.

These remaining existing tanks must be subject to the same degree of emissions control as is required for all other tanks. EPA estimates the existing population of condensate tanks in 2008 to be 57, 8447.[523] Such a standard would be cost-effective, especially if phased in over a reasonable time period. Colorado, for instance, developed cost data for retrofits of condensate tanks, concluding that condensate tanks could be retrofitted for

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515 TSD, Table 6-8.
516 EPA, *U.S. National Inventory of Sources and Sinks 1990-2009* (2011), Table A-120., p. A-122.
517 TSD, Table 6-22.
518 RIA, Table 3-3.
519 76 Fed. Reg. at 52,813. (Proposed 40 C.F.R. §63.766).
520 *Id.*
521 76 Fed. Reg. at 52,800. (Proposed 40 C.F.R. § 60.5395).
522 EPA has proposed to exempt some small throughput vessels from this standard.
523 TSD 7-4. Note the most recent GHG Inventory does not provide an estimate of the population of tanks used in the natural gas sector so this analysis relied on the information contained in the TSD rather than EPA's most recent GHG Inventory.

roughly $6,921 per tank.[524] Using the average VOC emissions for condensate and oil tanks presented in Table 7-12 of the TSD (103 Tpy) in 2008 the existing tanks population was responsible for the emission of 59,580,041 Tpy of VOCs into the atmosphere. If the NSPS 95% control requirement were extended to these sources, it would result in the removal of 56,601, 039 Tpy VOCs, and would also achieve substantial methane reductions.

In view of the potential for cost-effective emissions savings, Colorado requires existing tanks emitting more than one ton per year of VOCs within certain ozone nonattainment area to retrofit to meet a 95% emissions control requirement[525] within the first 90 days of producing a newly drilled, re-completed, re-fractured or otherwise stimulated well.[526] After that, controls may be removed provided the owner or operator can demonstrate that all of the tanks within his or her control meet system-wide emission limits.[527] EPA must apply the same approach nationally. Whatever control efficiency requirement it ultimately applies to new tanks must be extended to existing vessels which are not already covered by the NESHAP, and must be applied on a reasonably strict retrofit schedule.

4. Standards for Existing Wells

Well completions of hydraulically fractured wells[528] and liquids unloading from conventional wells[529] are two of the largest sources of methane and VOCs from the oil and natural gas industries. EPA proposes to define well completions and recompletions as modifications, which would trigger the performance standards. Proposed 40 C.F.R. § 60.5365. Unfortunately, EPA fails to regulate liquids unloading altogether. Above, we call for this failing to be rectified. As we note above, liquids unloading is a physical alteration of the well which increases emissions and thus should be considered a modification which would trigger performance standards.

If the proposed rule stands, and EPA also regulates liquids unloading and considers it to be a modification, EPA will be able to control the major sources of methane emissions from existing conventional and hydraulically fractured gas wells (even without a 111(d) standard). If, however, EPA alters the proposal concerning hydraulically fractured wells

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[524] Colorado Air Quality Control Commission, *Revised Final Economic Impact Analysis for Proposed Alternative #2 for Proposed State-Only Revisions to the Air Quality Control Commission's Reg. Number 7* (Dec. 11, 2008), attached hereto as Exhibit 162.
[525] CO. Department of Public Health and Environment Regulation 7 at XII.D & XVII.C; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities).
[526] CO. Department of Public Health and Environment Regulation 7 at XII.D; *see also* Colorado Oil and Gas Conservation Commission Rule 805(b)(2)(A) & (B) (requiring such retrofits in certain counties, and within ¼ mile of schools, hospitals, and similar facilities, for tanks that emit 5 Tpy of VOCs or more).
[527] CO. Department of Public Health and Environment Regulation 7 at XII.D.
[528] 76 Fed. Reg. at 52,756.
[529] US Greenhouse Gas Inventory, Table A-120 at A-149 – A-153.

or fails to consider liquids unloading as a modification in the final rule, it should issue 111(d) standards to fill any gaps.

Of course, the existing well standards should also reflect the greater coverage we recommend for new sources, *supra*. Most significantly, 111(d) standards should regulate oil wells, in addition to gas wells.

5. Standards for Leak Detection and Repair

EPA proposes to require all new gas processing plants to comply with the enhanced leak detection standards of subpart VVa, while existing plants will continue to be bound by the more relaxed standards of subpart VV.[530] This is not an effective approach. As EPA explains, subpart VVa not only captures more VOCs (and methane), it is also less expensive per ton of pollutant because "[a]lthough the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs" thanks to captured natural gas sales.[531]

EPA estimates there are 577 existing plants operating in the U.S. today.[532] Applying the annual emission reductions from implementing a Subpart VVa LDAR program to individual gas plants estimated in Table 8-13 of the TSD, extending the Subpart VVa requirements to existing sources would result in an additional reduction of 7,790 tons of VOCs from the atmosphere.

EPA must apply this more effective, and less expensive, standard to existing processing plants immediately. No technical or logistical efforts appear to require a long phase-in period, though some need to hire or train sufficient workers may delay phase-in somewhat. Even assuming some phase-in period, though operators and the public can benefit from enhanced leak control as soon as EPA extends these standards to existing sources.

6. State Models

As we have described above, standards in Colorado and Wyoming demonstrate that standards of performance to control air pollution from existing sources are both "achievable" and "adequately demonstrated".[533] To underline this point, we gather those requirements here. Table 3 table illustrates the scope of existing sources covered by Wyoming and Colorado's rules.

Table 3

[530] *See* 76 Fed. Reg. at 52,764.
[531] *Id.* at 52,765.
[532] TSD, 8-16.
[533] See 42 U.S.C. § 7411(1)(1) (defining "standard of performance"); 42 U.S.C. § 7411(d)(1).

Existing Source	Proposed NSPS	Wyoming	Colorado
Condensate tanks	95% control of tanks with emissions $\geq$ 6 Tpy VOCs.	CDAs and JPAD[534]: New and modified facilities must control VOC flash emissions by 98% upon first date of production (FDOP). May remove controls after one year if VOC emissions < 8 tpy. Statewide: New and modified facilities must control VOC flash emissions ≥10 tpy by 98% upon FDOP. May remove controls after one year if emissions < 8 tpy.	Tanks with VOC emissions greater than 2 Tpy, under common ownership and control, and with cumulative emissions = or > 30 Tpy VOCs located in ozone NA or Attainment/Maintenance area, must meet system-wide declining caps that require 90% control during ozone season and 70% control remainder of year.[535] Individual tanks located at gas processing plants in ozone NA or Attainment/Maintenance area, with emissions > 2 Tpy VOCs must achieve 95% control on rolling 12-month basis.[536] Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[537]
Crude oil tanks	95% control of tanks with VOC emissions $\geq$ 6 Tpy.	Same as condensate tanks.	Tanks with PTE 5 Tpy or more located near public places in the Piceance basin must achieve 95% VOC control.[538]
Produced water tanks	N/A	Same as condensate	Tanks with PTE 5 Tpy or more located near public places in the

534 *Id*. CDA refers to "Concentrated Areas of Development". JPAD refers to the Jonah and Pinedale Anticline Development Area.
535 Colorado Reg. 7, XII.D.2.(a)(x).
536 Reg. 7, XII.G.2.
537 Colorado Oil and Gas Conservatin Commission Rule ("COGCC") 805(b)(2)(A),(B).
538 Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).

		tanks.	Piceance basin must achieve 95% VOC control.[539]
Pneumatic devices	Low bleed devices in production and transmission sectors. No-bleed devices at gas plants.	Operators must use low or no-bleed devices or route discharge streams to closed loop systems.	New and existing gas-activated controllers at or upstream of gas processing plants in ozone nonattainment (NA) and Attainment/Maintenance areas (NA/M) must be low-bleed.[540] Statewide, new, replaced or repaired devices in production sector must be low or no-bleed, where technically feasible.[541]
Gas processing plants	N/A	N/A	Plants in ozone nonattainment areas or Attainment/Maintenance areas must comply with the same federal leak detection and repair standards that apply to new sources in subpart KKK.[542]
Wells	Reduced emission completions for re-completed and re-fractured hydraulically fractured gas wells.	Green completions.	Green completions.

Wyoming and Colorado's standards to control air pollution from existing storage vessels, pneumatic devices, and wells are based upon or reflect the same practices or standards that EPA has determined in this rule represent Best Demonstrated Technology, or Best System of Emission Reduction, for new sources. This fact demonstrates that these practices and standards are achievable and adequately demonstrated for existing sources as well. EPA thus must look to the Wyoming and Colorado standards when designing emission guidelines for existing sources as required by the Act.

7. Conclusion

[539] Colorado Oil and Gas Conservatin Commission Rule 805(b)(2)(A),(B).
[540] Reg. 7, XVII.
[541] COGCC Rule 805(b)(2)(E).
[542] Reg. 7, XII.G.3.

Section 111(d) and its implementing regulations require EPA to control VOCs and methane at existing sources as well as at new sources. As we have demonstrated, these existing source standards can readily be extrapolated from EPA's work on the new source performance standards, can be applied quickly, and are likely to be highly cost-effective, especially if phased in properly. As with the earlier landfill standards, oil and gas 111(d) standards will have significant public health and welfare benefits, reducing ozone formation, HAPs, and the sector's contribution to climate change. EPA must therefore include a proposal for such standards in or concurrent with its final rulemaking for the 111(b) standards, or include a schedule in the 111(b) rulemaking committing to a proposal in the near future.

VI. COMPLIANCE AND ENFORCEMENT ISSUES

EPA's proposed standards cover thousands of facilities spread across a wide range of terrains and jurisdictions. To properly enforce them, EPA and the states will need substantial resources and clear authority. In our sector-specific comments, we have made several suggestions for clarifying the rule to enhance its enforceability. In this section of the comments we consider enforcement issues more generally, focusing on the implications of EPA's proposal to exempt certain sources from permit requirements under Title V of the Clean Air Act and upon EPA's proposal to develop an affirmative defense for noncompliance. We trust these suggestions will help make the final rule enforceable as a practical matter, and thus ensure its full rigor, as well as overall transparency and widespread compliance.[543]

A. Title V Exemption

[543] With regard to transparency, it is important to note – and EPA must clarify -- that all information reported pursuant to proposed 40 C.F.R. §§ 60.5410, 60.5415, and 60.5420 must be disclosed to the public. Section 114 of the Clean Air Act authorizes EPA to collect information and mandates that this information be available to the public. EPA regulations provide that all data collected by EPA under any CAA provision will be presumed to have been collected under § 114, regardless of whether the authority providing for the collection cites § 114, and that this information will "shall" be public. 40 C.F.R. §§ 2.301(b)(2), (f). The only exception is that EPA may determine that certain information other than "emission data" is confidential business information that need not be disclosed. 42 U.S.C. § 7414(c). The exemption does not apply here, because all of the information reported pursuant to the proposed NSPS rules is "emission data." "Emission data means . . . [i]nformation necessary to determine the identity, amount, frequency, concentration, or other characteristics" of emissions actually emitted by a source or that the source was authorized to emit. 40 C.F.R. § 2.301(a)(2)(i)(A)-(B). This information includes "a description of the manner or rate of operation of the source" and a "general description of the location and/or nature of the source." *Id.* § 2.301(a)(2)(i)(B)-(C). The information required pursuant to the proposed NSPS falls solidly within this category. Although EPA has set technology or work practice standards for many sources, these standards serve as a surrogate for actual emissions. Even if this information was not emission data, nothing indicates that it would be confidential business information that EPA could shield from disclosure.

EPA proposes to exempt well completions, pneumatic devices, compressors and small storage tanks from the obligation to obtain Title V permits.[544] As a matter of law, promulgation of an NSPS regulating these entities would bring them within the ambit of Title V.[545] When promulgating an NSPS, however, EPA may exempt non-major sources from Title V obligations in the limited circumstances where compliance would be "impracticable, infeasible, or unnecessarily burdensome" for the source.[546] Here, EPA argues that Title V is an "unnecessary[] burden[]."[547] We strongly object to the proposed Title V exemption.

"Title V of the 1990 Amendments to the Clean Air Act (CAA) requires that certain air pollution sources, including every major stationary source of air pollution, each obtain a single, comprehensive operating permit to assure compliance with all emission limitations and other substantive CAA requirements that apply to the source."[548] Regulations implementing Title V are codified at 40 C.F.R. parts 70 and 71. A Title V permit must, *inter alia*, list all emissions limitations and standards applicable to the source;[549] ensure that monitoring and recordkeeping are sufficient to demonstrate compliance;[550] and require payment of fees.[551]

Rather than treating the statutory exemption as a narrow limitation on a rule of general applicability adopted by Congress, EPA seems to assume that the exemption is available as a matter of right, unless some added benefit can be demonstrated. Accordingly, instead of simply examining whether Title V permitting is "unnecessarily burdensome," EPA interprets the exemption as permitting it to balance the enforcement and environmental benefits of Title V against the costs to the facility operator.[552] Moreover, the proposed rule understates the benefits of Title V by completely ignoring the role Title V fees play in funding state enforcement programs. The proposal conversely assumes that costs to operators are unbearable without considering the ways in which these costs may (and are likely to) be reduced or providing any specific data regarding the magnitude of these costs and the operators' ability to bear them. Accordingly, the proposed title V exemption is insufficiently supported and, in any event, unwarranted.

1. EPA's Multifactor "Unnecessarily Burdensome" Test

[544] 76 Fed. Reg. at 52,799 (Proposed 40 C.F.R. § 60.5370(c)).
[545] 42 U.S.C. § 7661a(a), 40 C.F.R. § 70.3(a)(2).
[546] 42 U.S.C. 7661a(a), 40 C.F.R. § 70.3(b)(2).
[547] 76 Fed. Reg. at 52,751.
[548] *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 993-94 (D.C. Cir. 2005) (citing 42 U.S.C. §§ 7661a(a), 7661c(a)), attached hereto as Exhibit 163
[549] 40 C.F.R. § 70.6(a)(1)
[550] 40 C.F.R. § 70.6(a)(3);
[551] 40 C.F.R. §§ 70.6(7), 70.9.
[552] *Id.*

Following a trend established in several recent rulemakings, EPA's proposal discusses five factors in evaluating whether Title V imposes an unnecessary burden.[553,554] Specifically, EPA articulates a four-factor test, but then adds an additional consideration. The four factors are:

(1) Whether Title V would result in significant improvements to the [applicable substantive] compliance requirements . . .

(2) Whether Title V permitting would impose a significant burden on these non-major sources and whether that burden may be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies;

(3) Whether the costs of Title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources;

(4) Whether there are implementation and enforcement programs in place that are sufficient to assure compliance . . . without relying on Title V permits.[555]

After discussing these factors, EPA separately considers "whether exempting . . . [these] sources would adversely affect public health, welfare or the environment."[556]

As a threshold matter, we note the cumbersome nature of this test. The distinction, if any, between the first and fourth factors is unclear. Similarly, evaluation of effects on "public health, welfare or the environment" largely subsumes the question of whether Title V would improve compliance with substantive standards, because EPA must presume that those standards further these broader goals. Lastly, insofar as the fourth and fifth factors have independent relevance, EPA must discuss these factors before the third "factor," which itself appears to be merely a weighing of factor two against the other concerns. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations. Moreover, EPA's application of its factors in this instance would seem to allow it to exempt all sources. EPA has not

[553] 76 Fed. Reg. at 52,751 (citing *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75323 (Dec. 19, 2005)).

[554] EPA cites this document as the "Title V Exemption Rule." *See* 76 Fed. Reg. at 52751. Rather than announce a general rule regarding Title V exemptions, the cited rule was a case-specific determination as to whether five nonmajor source categories subject to NESHAP should be exempted from Title V. 70 Fed. Reg. at 75,320, 76,323, attached hereto as Exhibit 164. In the proposal and final rule for the five-category exemption, EPA used a test similar to the one EPA uses here. *Id.*, *see also Proposal To Exempt Area Sources Subject to NESHAP From Federal and State Operating Permit Programs*, 70 Fed. Reg. 15,250, 15,253 (March 25, 2005), attached hereto as Exhibit 174.

[555] *Id.*

[556] *Id.*

explained how the costs and benefits of Title V permitting in this instance are significantly different from the burden imposed on other sources that are subject to Title V obligations.

2. Title V Permit Fees Will Further Environmental Protection and Compliance with the NSPS

Assuming *arguendo* that EPA's test lays out a reasonable set of distinguishable factors, in discussing the three "benefit" factors of the above balancing test here, EPA failed to consider the important role Title V fees play in the CAA's regulatory regime.

In evaluating the first factor, EPA explained that "[o]ne way that Title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard."[557] EPA concluded the proposed NSPS's reporting, monitoring and recordkeeping requirements were, *e.g.*, "sufficient to assure compliance with the proposed [NSPS] requirements," such that the monitoring, reporting and recordkeeping required by Title V would provide little additional benefit.[558] We note that Title V requires "prompt reporting of deviations from permit requirements" and reporting on a semiannual, rather than annual, basis,[559] whereas the proposed NSPS only requires reporting on an annual basis, together with notification of well completions.[560] Timelier reporting would facilitate enforcement.

More importantly, reporting is not the only mechanism by which Title V improves compliance. Title V also improves compliance by requiring operators to pay fees that, in turn, fund state enforcement programs. Title V requires that permit programs impose and collect annual fees "sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program requirements of [Title V], including the reasonable costs of . . . implementing and enforcing the terms and conditions of any . . . permit (not including any court costs or other costs associated with any enforcement action)."[561] As EPA has interpreted this language, Title V permit fees may be used for all enforcement costs for Title V sources incurred prior to the filing of an administrative or judicial compliant.[562]

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[557] 76 Fed. Reg. at 52,752.
[558] *Id.*
[559] 40 C.F.R. § 70.6(a)(3)(iii)(B)
[560] 76 Fed. Reg. at 52,805-08 (Proposed 40 C.F.R. §§ 60.5410, 60.5415, 60.5420).
[561] 42 U.S.C. § 7661(b)(3)(A)(ii).
[562] *Reissuance of Guidance on Agency Review of State Fee Schedules for Operating Permits Programs Under Title V*, at pages 3 and 16 of 25 (Aug. 4, 1993), available at http://www.epa.gov/ttn/oarpg/t5/memoranda/fees893.pdf, attached hereto as Exhibit 166.

These fees are essential, because state budgets have slashed delegated CAA programs to the point where almost all available resources are derived either from CAA grants or Title V fees. For example, Oregon's Department of Environmental Quality states that

> Because other funding sources have become less available over time, fees pay for 90 to 95 percent of the Air Contaminant Discharge Permit Program. To address budget shortfalls, the Oregon Legislature has cut general fund support for the Air Contaminant Discharge Permit Program and shifted more of the funding to fees. Federal funds for state air quality programs have been flat for many years, and prospects for significant increases in federal funds are slim given federal budget challenges.[563]

Because Title V permit fees cannot be used for purposes other than enforcement and implementation of the Title V program, Title V fees directly and necessarily increase enforcement capacity.

EPA itself implicitly concedes that states lack the resources to enforce the proposed NSPS obligations. In discussing the status of implementation and enforcement programs (the fourth "unnecessarily burdensome" factor), EPA states that

> Before EPA will delegate [the NSPS] program [to a state], EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to ensure compliance with this NSPS.[564]

Although EPA retains legal authority to enforce the NSPS where states fail to do so (*e.g.*, because of a lack of funding), EPA has not examined whether EPA itself has the resources to enforce these requirements nationwide without the benefit of Title V permit fees.

It is difficult to imagine how EPA can conclude that publicly taking the cop off the beat by eliminating the principal source of funding for many state enforcement programs will have no effect on compliance rates. Such an assumption is plainly arbitrary and capricious, and unsupported by the record.

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[563] http://www.deq.state.or.us/aq/permit/index.htm (last visited Oct. 24, 2011), attached hereto as Exhibit 167.
[564] 76 Fed. Reg. at 52,753.

Title V permitting also serves to improve compliance by increasing transparency and providing a vehicle where questions of the applicability of the NSPS (and the several exemptions thereto) are identified and resolved. Under EPA's proposal sources would decide these issues with no opportunity for upfront state or federal review or public disclosure of a decision by the source that it believed the standard did not apply.

Third party verification does not obviate the need for Title V fees. The preamble to the proposed rule states that EPA "want[s] to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[565] Even if third party verifiers were capable of substituting for government enforcement, EPA has provided no evidence that the cost to industry of third party verifiers sufficient to play this role would be less than the cost of an efficiently structured Title V program.

Thus, Title V protects the environment and ensures compliance with NSPS requirements both by mandating reporting and by funding enforcement programs. Title V also increases compliance is by facilitating judicial enforcement. A Title V program must "provide for judicial review of permitting actions."[566] Another benefit of Title V EPA does not discuss is the fact that Title V permittees are required to submit annual compliance plans and compliance certifications. 42 USC 7661b(b)(1),(2); 40 CFR 71.5(d). Failure to do so, and knowing false material statements in the certifications is subject to criminal penalties. 42 USC 7413(c)(1),(2).

3. EPA overstates the burden of the Title V program

While EPA has understated the benefits of the Title V program, EPA has overstated the burden the program imposes on facility operators. EPA has provided scant and flawed information regarding costs of compliance, ignored ways in which the Title V program may and would likely be streamlined, and provided no information regarding facilities' ability to bear these costs.

EPA begins with an overstated estimate of the costs of compliance. "EPA estimated that the average cost of obtaining and complying with a Title V permit was $65,700 per source for a 5-year permit period, including fees."[567] EPA bases this figure on an "Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07."[568] We have been unable to locate this supporting information in the docket or on EPA's website; only the information request, rather than the conclusions drawn from the responses thereto, appears to be available in the

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[565] 76 Fed. Reg. at 52,750.

[566] *Arizona Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1284 (D.C. Cir. 2000) (citing 42 U.S.C. § 7661a(b)(6), (7)), attached hereto as Exhibit 168.

[567] 76 Fed. Reg. at 52,753.

[568] *Id.*

Federal Register.[569] The $65,700 figure apparently represents the average across all facilities subject to Title V, including major sources under the PSD and NESHAP programs, and therefore does not represent the average cost of compliance for non-major sources subject solely to NSPS, such as the facilities being regulated here.[570]

Rather, based upon EPA's "presumptive minimum Title V fee" of $46.00 per ton of Title V pollutant actually emitted,[571] and EPA's statement that VOC emissions from a wellhead controlled with a green completion would be about 2.3 tons,[572] the federal minimum permit fee would be 2.3 times $46, or $105.80 per hydraulic fracturing operation. This cost is not even remotely unreasonable. It is trivial when compared to the value of the product generated, even for "small" operators.

Further, EPA failed to consider other tools to lessen the (already low) cost of Title V compliance. For example, permitting authorities may issue "general permits" encompassing a class of similar sources.[573] Numerous states have adopted general Title V permits for dozens of sectors.[574]

General permits can significantly ease the costs of compliance. In one context, EPA has stated that a normal Title V permit requires 200 hours of "permit renewal" work per year, whereas re-application for a general permit requires only two hours per year.[575] In this circumstance, where EPA has determined that the majority of the Title V monitoring, recording and recordkeeping overlaps with that required by the proposed NSPS, the permit application and renewal hours presumably constitute a large fraction of the burden imposed by Title V. Thus, reducing those hours by a factor of 100 would significantly reduce the costs of Title V compliance. In other cases where EPA has exempted sources from Title V, EPA has done so only after explicitly stating that Title V would remain unnecessarily burdensome even if general permits were used to reduce costs.[576,577] Although we contend that these rulemakings' often-cursory dismissal of

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[569] *See Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; State Operating Permit Regulations (Renewal); EPA ICR No. 1587.07, OMB Control No. 2060–0243*, 72 Fed. Reg. 32,289 (June 12, 2007), attached hereto as Exhibit 169.

[570] *See Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,325 (Dec. 19, 2005) (discussing limits of the preceding 2004 Information Collection Request).

[571] *See* http://www.epa.gov/airquality/permits/historicalrates.html, attached hereto as Exhibit 170.

[572] RIA at 3-6.

[573] 40 C.F.R. § 70.6(d).

[574] *See Tool Selection Guide: A Review of Permitting Options for Implementing Area Source Rules*, Report to EPA prepared by Industrial Economics, Inc. pp. 17-26 (Nov. 11, 2009) (available at http://www.epa.gov/erp/files/selectionguide.pdf) (cataloguing and summarizing general permit programs in six states), attached hereto as Exhibit 171.

[575] *Exemption of Certain Area Sources From Title V Operating Permit Programs*, 70 Fed. Reg. 75,320, 75,341 (Dec. 19, 2005).

[576] *See, e.g.*, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Chemical Preparations Industry*, 74 Fed. Reg. 39,013, 39,021 (Aug. 5, 2009), attached hereto as Exhibit 172, *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. 26,142, 26,152 (June 1, 2009), attached hereto as Exhibit 173.

general permits was inadequate, EPA did not even mention the possibility of using general permits here.

EPA also underestimates industry's ability to bear the costs of Title V compliance. EPA states that "some of the non-major sources that would be subject to the proposed NSPS *may* be small entities that *may* lack the technical resources [sic] and, therefore, need assistance from the permitting authorities to comply with the Title V permitting requirements."[578] EPA purports to support this conjecture by noting the sheer number of annually affected *facilities* (20,000 well completions, 14,000 new controller installations, 500 compressors and 300 storage vessels), but EPA provides no data regarding the number of *businesses* operating these facilities. Thus, EPA's mere speculation that "some" operators "may" be small and "may" lack technical expertise provides no justification for concluding that regulated entities will be unable to bear the costs of Title V compliance. Larger entities have greater financial resources and, perhaps more importantly, economies of scale relating to Title V technical expertise which will drive down the cost of compliance per facility. Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document. Moreover, in addition to specifically authorizing general permits, the Act also specifically authorizes the issuance of one permit for a facility with multiple sources.[579] Thus, the operator of a well field with 100 wells would only need to get a single general permit in order to comply with Title V permitting requirement.

Whereas EPA provides no information about the number of small entities regulated here, in other recent rulemakings EPA has only held that Title V exemptions were

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[577] See also *Revision of Source Category List for Standards Under Section 112(k) of the Clean Air Act; National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. 6,510-01, 6,521 (Feb. 9, 2009), attached hereto as Exhibit 174; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Nine Metal Fabrication and Finishing Source Categories*, 73 Fed. Reg. 18,334-01, 18,359 (Apr. 3, 2008), attached hereto as Exhibit 175; *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008), attached hereto as Exhibit 176; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Clay Ceramics Manufacturing, Glass Manufacturing, and Secondary Nonferrous Metals Processing*, 72 Fed. Reg. 53,838-01, 53,850 (Sept. 20, 2007), attached hereto as Exhibit 177; *National Emission Standards for Hazardous Air Pollutants for Area Sources: Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery Manufacturing, and Wood Preserving*, 72 Fed. Reg. 38,864-01, 38,875 (July 26, 2007), attached hereto as Exhibit 178.

[578] 76 Fed. Reg. at 52,753. EPA fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[579] See 42 U.S.C. 7661a(c).

warranted when EPA had specific information regarding the proportion of small businesses affected.[580] Here, EPA has provided no information indicating that any appreciable fraction of sources are owned by "small" business entities that lack technical acumen or that have particularly limited ability to bear the costs of Title V compliance.[581]

Here, it is important to recognize that the "technical expertise" that will be required is that needed to comply with the underlying NSPS, not the Title V permit. Small operators with limited technical expertise respecting the performance of low-bleed controllers or dual double dry seals for compressors may need to obtain assistance. However, the Title V permit adds no substantive compliance obligation, it merely makes sure that all Federal obligations applicable to a source can be found in one document.[582]

In summary, EPA has ignored the role Title V fees play in ensuring NSPS compliance; failed to demonstrate that, absent fees, states or EPA have capacity to enforce the NSPS; and failed to show that Title V imposes burdens that are disproportionate to its benefits or that regulated facilities are unable to bear. Accordingly, EPA must withdraw its proposal to exempt well completions, compressors, pneumatic devices and small storage tanks from the requirement to seek and hold Title V operating permits.

4. EPA's Third Party Verification Plans are Ill-Defined

EPA briefly proposes a "third party verification" program as a "complement" to the annual compliance certification. [583]EPA has not, however, provided a coherent explanation as to the role these verifiers would play. Without a clear picture as to the role of these private actors, it is impossible to comment on the appropriateness of their use. We accordingly object to adoption of a third-party verification system for the

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[580] *Standards for Paints and Allied Products Manufacturing*, 74 Fed. Reg. at 26,152 ("almost all of the approximately 2,190 paints and allied products manufacturing facilities that would be affected by this proposed rule are small entities; over half have nine or fewer employees."), attached hereto as Exhibit 179; *Standards for Aluminum, Copper, and Other Nonferrous Foundries*, 74 Fed. Reg. at 6521 ("approximately 98 percent of the plants that would be affected by the proposed rule are small businesses, most with fewer than 50 employees and about 25 percent or more with only one to four employees."), *National Emission Standards for Hazardous Air Pollutants: Area Source Standards for Plating and Polishing Operations*, 73 Fed. Reg. 14,126-01, 14,141 (March 14, 2008) ("nearly all of the approximately 2,900 plating and polishing facilities affected by this proposed rule are small businesses, some with as few as one or two employees.").

[581] Although EPA's prior rulemakings have looked to the raw number of businesses and looked to the fraction of this number constituted by "small" business, a better approach would be to look to the fraction of *facilities* owned by small business.

[582] EPA also fails to mention that Title V permitting assistance is currently provided as a routine matter by permitting authorities.

[583] 76 Fed. Reg. at 52,750.

proposed O&G NSPS at this time. We nonetheless alternatively offer the following comments on third party verification generally.

A threshold question, which EPA has not answered, but must address, is why it proposes to use third party verification at all in this context. EPA "state[s] clearly [in its proposal] that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and EPA."[584] EPA has not identified any function that third party verifiers can perform more effectively, or more cheaply, than can permitting authorities. Thus, there is no apparent reason to require industry to fund third party verifiers through some yet un-described system instead of requiring industry to fund verification by the permitting agencies through title V. We are particularly troubled by the possibility that EPA sees its vague proposal for third-party verifiers as justification for exempting wellheads, compressors, pneumatic devices and small storage tanks from title V. To be clear, the proposal itself explicitly disclaims such reliance. EPA has stated that third party verification would not displace government inspection and regulation, and EPA's discussion of the proposed title V exemption does not refer to third party verifiers. Nonetheless, we wish to highlight the fact that EPA cannot and should not substitute an undefined private framework for an established regulatory regime with well-defined provisions for public disclosure and judicial enforcement.

A second issue, which EPA recognizes, is that "third party verification paid for by industry" presents a potential conflict of interest that can compromise the verification's validity. In the late 1990s, EPA's National Enforcement Investigations Center audits of private LDAR monitoring "show[ed] that the number of leaking valves and components is up to 10 times greater than had been reported by certain re-fineries"; these reports included reports generated by third parties.[585] In light of this history, any proposal for third party verification must, at minimum, address conflicts of interest by incorporating an accreditation scheme and by requiring verifiers to be paid through an industry consortium rather than by individual facilities. For a model accreditation scheme, EPA could look to the California Air Resources Board's accreditation of third party verifiers adopted pursuant to California's greenhouse gas reporting rule.[586] EPA could similarly accredit and oversee third party verifiers, requiring that only accredited verifiers be used. EPA could also require that third party verifiers be paid by an industry consortium, rather than by individual facilities, attenuating the financial connection and accompanying conflict. EPA must further explore schemes under which the permitting authority, rather than the facility operator, selects the verifier to be used in particular

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[584] *Id.*

[585] EPA Office of Regulatory Enforcement, *Proper Monitoring Essential to Reducing 'Fugitive Emissions' Under Leak Detection and Repair Programs* (Oct. 1999), *available at* http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/emissions.pdf, attached hereto as Exhibit 180.

[586] *See* www.arb.ca.gov/cc/reporting/ghg-ver/ghg-ver.htm.

cases. If it moves forward, it must use such a model, or explain why it has failed to do so.

If third party verifiers are used, any information they collect should be as fully available to the public, comparable to information collected by EPA. EPA asks whether third party verifiers could serve as a "clearinghouse for notifications, records and compliance certifications."[587] Any such clearinghouse should be fully available online and provide the general public with full access to the collected data, on a searchable and tabular basis.

Finally, we address the roles EPA has proposed for third party verifiers. We have no objection to above-mentioned "clearinghouse" role, provided that the role does not substitute for government verification and that all data is publicly available. We nonetheless disagree with EPA's suggestion that with such a clearinghouse, "notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary."[588] EPA has not explained how the clearinghouse would obviate the need for such advanced notification. Although notification through a clearinghouse might be more efficient than other notification methods, the role of advanced notification is to enable states and EPA to inspect well completions as they occur, and significant advanced notice is likely to facilitate scheduling of such inspections. An online clearing house would not solve this scheduling problem.

The second role EPA suggests for third-party verifiers is to assist states and EPA in "review[ing] and verify[ing]" data submitted through EPA's electronic reporting tool. In light of the conflict of interest mentioned above, private verifiers must not displace government review and enforcement of NSPS requirements. Absent a more definite proposal, we oppose using third-party verifiers in this way.

Third, EPA alludes to using third party verifiers to inspect facilities in the field. This role is implied by EPA's statement that third-party verification can be useful in light of the geographically dispersed and remote nature of facilities, although it is not directly discussed by EPA. Provided that third-party verifiers are limited to collection of unarguably objective data, such as the type of compressor installed, we do not object to this *type* of verification. Nonetheless, because EPA has not proposed a specific framework for verification, and because the implementation details are critically important, we oppose using third party verifiers in this role until EPA offers a more detailed proposal for public comment.

B. The Affirmative Defense

[587] 76 Fed. Reg. at 52,750.
[588] *Id.*

EPA unlawfully proposes to promulgate an "affirmative defense" to penalties due to a malfunction.[589] This would create a new loophole in the standards and is unlawful. It also would have harmful consequences for local communities affected by oil and gas production, and will greatly reduce the deterrent impact of the proposed standards.

The statute makes clear how the courts are to assess civil penalties, whether a case is brought by EPA or a citizen.[590] Congress plainly intended citizens to be able to enforce emission standards under the CAA using the full range of civil enforcement mechanisms available to the government. EPA's rule proposal, by shifting this careful balance and contravening these mandates, violates the CAA.

The affirmative defense that EPA proposes to allow in case of malfunctions goes directly against congressional intent in two ways. First, Congress expressed a clear intent as to how judges should determine the size of civil penalties whenever they are sought and thus Congress flatly barred EPA from limiting when civil penalties can be assessed.[591] In this proposal, EPA acts outside of its delegated authority to limit civil penalties available in citizen suits or its own enforcement actions. Second, the proposal will impermissibly chill citizen participation, and the ability to win an effective, deterrent remedy, in CAA enforcement actions.

The affirmative defense is fatally flawed because EPA does not have the authority to decide when civil penalties will not be allowed. The CAA itself spells out the only limits that Congress intended to impose on citizens' ability to seek and recover penalties in enforcement suits under CAA § 304, 42 U.S.C. § 7604.[592] By attempting to impose additional agency-created limits, EPA exceeds its authority.

Congressional intent on civil penalties is clear—they are a remedy available for enforcement by citizen plaintiffs, and the Act gives judges a list of factors to consider in assessing them.[593] As such, EPA cannot interpret the statute to contravene that intent.[594] By attempting to rewrite this provision, via regulation, EPA has done just that.

[589] *See* 76 Fed. Reg. at 52,807 (proposing 40 C.F.R. § 60.5415(h)).
[590] 42 U.S.C. § 7413(e).
[591] *See Chevron, U.S.A., Inc. v. Natural Res. Def. Council, Inc*., 467 U.S. 837, 842-43 (1984), attached hereto as Exhibit 181.
[592] *See* 42 U.S.C. § 7413(e).
[593] *Sackett v. EPA*, 622 F.3d 1139, 1146-47 (9th Cir. 2010) *cert. granted in part,* 131 S. Ct. 3092 (2011) (in interpreting analogous penalty provision of Clean Water Act, 33 U.S.C. § 1319(d) holding that "the civil penalties provision is committed to judicial, not agency, discretion."), attached hereto as Exhibit 182.
[594] *See Chevron*, 467 U.S. at 842-43; *see also Barnhart v. Sigmon Coal Co.*, 534 U.S. 438, 462 (2002) ("We will not alter the text in order to satisfy the policy preferences of the Commissioner."), attached hereto as Exhibit 183; *North Carolina v. EPA*, 531 F.3d 896, 910 (D.C. Cir. 2008) ("All the policy reasons in the world cannot justify an agency reading a substantive provision out of a statute."), attached hereto as Exhibit 184.

The CAA grants EPA minimal discretion that only applies to administrative penalties, allowing EPA to "compromise, modify, or remit, with or without conditions, any administrative penalty which may be imposed under [subsection 113(d)]."[595] However, there is no similar grant of authority to EPA to compromise, modify or limit civil penalties that a court may impose under section 113(e) or section 304. Section 304(a), 42 U.S.C. § 7604(a), grants courts the sole authority "to apply any appropriate civil penalties" in citizen suits. The explicit reference to EPA's ability to modify penalties in one subsection and its absence in the other subsection of the same provision can only be understood as an intentional decision by Congress that EPA may not contravene by rule.

If a local community group sued a covered facility for a violation of the emission standards, the owner might argue that it is exempt from paying civil penalties so long as the owner satisfied the requirements set forth in EPA's proposed affirmative defense regulations.[596] The owner must not be able to evade civil penalties that apply when the congressionally mandated factors in the statute are met.[597,598] It is improper for a court to fail to consider these factors, or to fail to make its own determination of what civil penalties are "appropriate" under CAA § 304(a), and EPA must not ask a court to ignore its legal duty.[599] Notably, courts interpreting the analogous provision of the Clean Water Act have held that the statutorily enumerated factors cannot warrant elimination of a penalty.[600,601] *A fortiori* it is impermissible for EPA to attempt to displace those

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[595] 42 U.S.C. § 7413(d)(2)(B).

[596] *See* 76 Fed. Reg. at 52,813-14, 52,829-30 (proposing 40 C.F.R. §§ 63.761-62, §§ 63.1271-72).

[597] *See* 42 U.S.C. § 7413(e) (listing factors).

[598] Note that the proposed exemption would also be barred under *Chevron* step two or found to be arbitrary and capricious since, even if there exists some slight ambiguity, it is unreasonable to construe the statute as permitting EPA to short-circuit the consideration of specifically listed factors. *See Chevron*, 467 U.S. at 843 (explaining that if the statute does not answer the question at issue, "the question for the court is whether the agency's answer is based on a permissible construction of the statute"); *S. Coast Air Quality Mgmt. Dist. v. EP*A, 472 F.3d 882, 895 (D.C. Cir. 2006) ("We further hold that EPA's interpretation of the Act in a manner to maximize its own discretion is unreasonable because the clear intent of Congress in enacting the 1990 Amendments was to the contrary."), attached hereto as Exhibit 185; *see also Gen. Instrument Corp. v. F.C.C.*, 213 F.3d 724, 732 (D.C. Cir. 2000) (explaining that "an arbitrary and capricious claim and a *Chevron* step two argument overlap"), attached hereto as Exhibit 186; *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (explaining that agency acts in arbitrary and capricious manner if it fails to consider "relevant factors" or "entirely fail[s] to consider an important aspect of the problem"), attached hereto as Exhibit 187. By "upset[ting] the statutory balance struck by Congress," as discussed above, the affirmative defense is unreasonable under *Chevron* step two. *Int'l Alliance of Theatrical & Stage Employees v. N.L.R.B*, 334 F.3d 27, 35 (D.C. Cir. 2003), attached hereto as Exhibit 188.

[599] It is also improper for EPA to fail to consider the section 113(e)(1) factors in situations in which it is setting the penalty. CAA § 113(e)(1), 42 U.S.C. § 7413(e)(1); *see also N.Y. Cross Harbor R.R. v. Surface Transp. Bd.*, 374 F.3d 1177, 1184 (D.C. Cir. 2004) (holding that "Board's failure to balance the competing interests . . . requires" vacatur of agency action).

[600] *See United States v. Lexington-Fayette Urban County Gov't*, 591 F.3d 484, 488 (6th Cir. 2010) (collecting cases from the Fourth, Sixth, Ninth, and Eleventh Circuits), attached hereto as Exhibit 189.

factors or in any way alter their significance by creating a bar to penalties if certain agency-defined considerations are met instead.

Citizen participation in CAA enforcement also will be hindered, in violation of citizens' rights to protect themselves from pollution and in direct conflict with congressional intent. The affirmative defense would likely be used on a routine basis by polluters seeking to avoid penalties, just as the malfunction exemption was. As a result, citizens who seek the assessment of civil penalties against polluters in order to protect themselves and achieve the Act's goals may be forced to engage in fact-intensive disputes over the cause of emission violations and adequacy of responsive measures – an outcome Congress intended to prevent with the simple straightforward enforcement and penalty provisions in the Clean Air Act. As a result, enforcement of the Act could suffer, for civil penalties provide a powerful deterrent to violators as Congress intended. As the Supreme Court explained: "To the extent that they [civil penalties] encourage defendants to discontinue current violations and deter them from committing future ones, they afford redress to citizen plaintiffs who are injured or threatened with injury as a consequence of ongoing unlawful conduct."[602,603]

Thus, the affirmative defense also runs counter to two clearly expressed intentions of Congress: (1) the burden it places on citizens makes it less likely that they will enforce the Act;[604] and (2) several of the factors at issue in the affirmative defense undercut Congress's intent that citizen suit enforcement should avoid re-delving into "technological or other considerations."[605] Both result from the technical burden EPA imposes on citizens with the affirmative defense, and both render the defense impermissible.

In addition to these problems, there is simply no need for an affirmative defense to penalties to be written into the regulations and cause the harm that will result. EPA has discretion to decide what cases to prosecute, to consider settlements, and to request

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[601] In another proceeding, EPA has argued that it may promulgate such an affirmative defense as an interpretation of the 'catchall' provision of CAA § 113(e)(1), which directs "the Administrator or the court, as appropriate," to consider the enumerated factors and "such other factors as justice may require." Partial Approval of Texas SIP, 75 FR 68,989, 68,999 (Nov. 10, 2010), attached hereto as Exhibit 190. As noted above, this provision represents a Congressional delegation of discretion to judges, not EPA. *United States v. Mead Corp.*, 533 U.S. 218, 226-27 (2001) (agencies enjoy *Chevron* deference where it is reasonable to presume that Congress delegated interpretive authority to the agency), attached hereto as Exhibit 191. Even if EPA has authority to interpret "other factors," the affirmative defense would require a court to elevate these additional factors above those enumerated by the statute.

[602] *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs.*, 528 U.S. 167, 186 (2000), attached hereto as Exhibit 192.

[603] S. Rep. 101-228, at 373 (1989), *as reprinted in* 1990 U.S.C.C.A.N. 3385, 3756, attached hereto as Exhibit 193.

[604] *See, e.g.*, *Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986), attached hereto as Exhibit 194.

[605] *NRDC v. Train*, 510 F.2d 692, 724 (D.C. Cir. 1974)

civil penalties in a case-by-case manner, as long as it acts consistent with the Clean Air Act to protect clean air as its top priority.[606] Promulgating this affirmative defense is equivalent to giving polluters "get out of jail free" cards for serious emission exceedances and MACT violations. Polluters are likely to claim that any violation of the standard is due to a malfunction in order to evade the requirements. Allowing polluters to evade financial penalties – which are the real teeth of the standards – through this type of measure is likely to lead to polluters simply ignoring or factoring potential standard violations into their cost of doing business, rather than actually trying to prevent malfunctions and violations of the standards as a way to avoid financial losses from the application of penalties.

Assuming *arguendo* that EPA had authority to promulgate any type of affirmative defense to penalties for malfunctions, EPA is required by statute to also promulgate the following provisions:

1. A specific amount of compensatory penalties must apply to each reported malfunction (consistent with the Act). These funds must be dedicated to enforcement, inspections, and monitoring in the local community around the specific facility, to create greater assurance that malfunctions will not happen again.

2. EPA must modify the regulations so that the affirmative defense cannot be used by a specific facility or company more than once within a set period of time, such as 10 years. The affirmative defense must become automatically unavailable to a facility that has previously had a malfunction within the last 10 years, to ensure that this defense does not swallow the value of the standards.

3. EPA must promulgate specific public reporting and notification requirements for malfunctions, or any emission exceedance that occurs of which an operator is aware. Specifically, EPA must require that when a facility provides EPA with a notification of a malfunction or emission standard exceedance under the regulations, this notice will be made publicly available on EPA's website within 14 days. In addition, EPA must promulgate the requirement that when such notification is made, the facility must also provide for community notification of the malfunction or emission standard exceedance within 2 business days, through an appropriate public forum that is designed to reach residents who live near the facility, including but not limited to a notice on the facility's own website (if it has one), a written notice to the local municipality and local school district, a press release to the local newspaper, radio, and TV news

[606] *See* 42 U.S.C. § 7401.

station that contains information community members may need to protect themselves and their families from the additional air pollution.

Commenters urge EPA not to adopt an affirmative defense that undermines citizen rights and remedies under the Clean Air Act. People living near oil and gas facilities are exposed to unacceptably high levels of hazardous air pollution that no one should have to face simply because of where they live. EPA may not lawfully use a regulation to take away a right granted to citizens by Congress. EPA must work to expand and protect the ability of people harmed by air pollution to seek all appropriate and available forms of relief in court. EPA must not retract or weaken citizen rights and remedies, as this proposal does, by making it more difficult for people to win meaningful relief from facilities that have released toxic air pollution into their communities for years.

Commenters support EPA's proposal for electronic reporting of data.[607] If EPA were to finalize any form of an affirmative defense, it must require that all reports related to that defense be submitted electronically and EPA must also make these reports available immediately to the public on its website, as discussed above. As the public has a right to all collected reports under the Clean Air Act, 42 U.S.C. § 7414(c), EPA must require immediate disclosure to the public on the Internet, without the need for any person to submit a FOIA request for such a report.

VII. EPA HAS OVERESTIMATED THE COSTS AND UNDERESTIMATED THE BENEFITS OF ITS PROPOSAL

A. EPA's Consideration of Costs Under Section 111 and the Regulatory Impacts Analysis

As we demonstrate above, EPA's proposal is based upon readily achievable methods, the costs of which are reasonable. In this section of our comments, we delve deeper into the costs and benefits of the rule, demonstrating that the rule has significantly greater economic and social benefits than EPA suggests.

EPA must, under section 111 of the Act, issue standards of performance that

> reflect[ ] 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 requirements) the Administrator determines has been adequately demonstrated.[608]

[607] 76 Fed. Reg. at 52,748, 52,825, 52,840.
[608] 42 U.S.C. § 7411(a)(1) (emphasis added).

Under this plain language, EPA must consider the costs of control, i.e., those that the sector incurs to achieve the emission reduction from the affected facility to which the standard applies, in setting a standard of performance; it may not base its standard-setting on a broad-ranging cost-benefit analysis.[609]

Below, we demonstrate that these costs of control are frequently over-stated with respect to the proposal. EPA regularly uses very conservative data to calculate costs. A more realistic assessment would show that the rule has substantially lower costs than EPA acknowledges. We also show that EPA's estimates of the rule's direct financial benefits, through the capture of natural gas and condensate, are low. The natural gas prices EPA uses to calculate these benefits are far lower than all other projections. EPA must use a realistic gas price in its analysis, which would accurately value the savings that the standards will achieve. Doing so will significantly lower the cost of control EPA uses in its standard setting process.

We also address EPA's discussion of the benefits of the rule, which it developed in its Regulatory Impact Analysis (RIA), which did include a cost-benefit analysis, as part of its compliance with Executive Order 12866, "Regulatory Planning and Review."[610] Importantly, while the RIA provides important information on the impacts of the proposed rule, EPA's standard-setting duties and authority are derived under section 111 of the Act and its decision must be made within the confines of that authority, although it may be described and informed by the RIA.[611] As such, our critique of the RIA largely addresses how EPA and other government actors are to understand the economic impact of the rule. It does not bear directly on the standard setting process itself.

With regard to the RIA, we show that EPA has not properly accounted for the substantial benefits the rule creates by capturing methane as a co-benefit of VOC regulation. These co-benefits include both substantial reductions in climate change-causing pollution, and a reduction in ground-level ozone, of which methane is a precursor. While EPA provided an estimate of the climate-linked financial benefits of the methane reductions in the RIA (an estimate of the "social cost" of methane), it chose "not to compare these co-benefit

[609] *Id.; see also Motor & Equipment Mfrs. Assn. v. EPA*, 627 F.2d 1095, 1117-18 (D.C. Cir. 1979) (in interpreting "cost of compliance" for vehicle emission standards under section 202(a)(2), rejecting industry's claim that EPA must consider broad social costs), attached hereto as Exhibit 195; *American Textile Manufacturers Inst. v. Donovan*, 452 U.S. 490, 510-11 (1981) (explaining that "Congress uses specific language when intending that an agency engage in cost-benefit analysis."), attached hereto as Exhibit 196. We note that section 111(h) imposes identical cost of control considerations upon EPA, and so our discussion of the cost of control of EPA's standards applies to those controls as well. *See* 42 U.S.C. § 7411(h)(1).

[610] *See* 76 Fed. Reg. at 52,794 (citing 58 Fed. Reg. 51,735 (Oct. 4, 1994)).

[611] *See* E.O. 12866 Section 10, "Judicial review," attached hereto as Exhibit 197. "Nothing in this Executive order shall affect any otherwise available judicial review of agency action. This Executive order is intended only to improve the internal management of the Federal Government and does not create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States…."

estimates to the costs of the rule for this proposal," but rather only to explore methane co-benefits in supporting documents as an "interim method."[612] For the reasons set forth below, we believe that EPA must include the methane co-benefits in its comparison of the proposed rule's costs and benefits. We also propose ways in which the social-cost-of-methane assessment can be improved by EPA in this rulemaking, and corrections and improvements to the underlying "social cost of carbon" analysis that should be made by the Interagency Working Group on the Social Cost of Carbon. We also discuss substantial ozone reduction co-benefits that will occur with the methane reductions, which will produce substantial public health and welfare improvements. Without these corrections and improvements, the figures provided by EPA significantly underestimate the social benefits of methane reductions from the proposed rule.

B. EPA Overestimated the Costs of Its Proposed Rule

1. The Costs of the Standards are Reasonable Under Section 111

In its evaluation of costs supporting the proposed rule under section 111, EPA assessed the cost of control for various affected facilities and technologies, finding the costs associated with each adopted measure to be reasonable. It then took into account, for control technologies capturing natural gas, the additional savings due to resale of captured gas where such resale is feasible. We compared these EPA estimates to figures from other EPA reports and industry information, and generally conclude that EPA's estimates range from reasonable to very conservative. In some instances, EPA overestimates the cost of control; in others, it underestimates the volume of gas reduced for a given cost; and in some cases it both overestimates the costs and underestimates the emissions controlled. When added to EPA's underestimation of the price of natural gas, taking account of these factors supports that the proposed rule's costs are lower than EPA recognizes.

Our focus throughout is upon the cost per ton of emission reduction, as this is the metric that EPA used to show that the proposed standards impose reasonable costs, consistent with section 111's required considerations.[613]

Our assessment is based on:

- Quantitative cost of control comparisons between EPA's estimates and other estimates, by control technology;
- Qualitative considerations that contextualize and add to the above comparisons; and

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[612] RIA at 4-33.
[613] We do not necessarily agree that a dollars-per-ton-of-pollutant-controlled metric is the appropriate gauge for costs under section 111(a)(1), as some measures may impose reasonable costs within the meaning of the statute even if they exceed some EPA threshold for cost effectiveness.

- Analysis of the forecasted price of natural gas forecasted, and its divergence from EPA's estimate.

Although we have done our best to unpack EPA's assumptions, EPA's cost calculations and methodology are not transparent. EPA must more clearly describe its "cost of control" methodology in the final rule, including its calculations and sources.

2. Quantitative comparison of the cost of control technologies

For each technology, we have compared available EPA TSD estimates to other sources, including: Past EPA reports and presentations particularly related to its Natural Gas STAR program; EPA's Methane to Markets Partnership (recently transformed into the Global Methane Initiative) presentations derived from methane reduction successes in the US and thirteen other countries; independent company reports; independent consultant reports; and journal publications.

Different data sources and analyses report costs in different ways (e.g., yearly profit, net present value, payback). We have tabulated the available data to facilitate a like-for-like comparison. Where helpful, we have translated reported data in ways that best fit into the table. But, in many instances the available information was insufficient to populate the entire cost-effectiveness breakdown; in these instances, we have still included all available data. Where possible, we estimated cost per year (or per device, as applicable), savings per year (or per device), profitability per year (or per device) and the payback of the investment. We used the latter two metrics as prime indicators of the cost-effectiveness of the control technologies. These are highlighted in the tables below.

For natural gas prices, where data for the volume of natural gas savings was available, we assumed the price of natural gas to be $4/Mcf, to align with EPA's calculations. When volumes were not directly available in the data sources, in most cases we scaled these savings to what the savings would have been at a natural gas price of $4/Mcf. In some cases, we had insufficient data or visibility to scale the savings and left it unaltered (but in these instances noted the likely price of natural gas applicable). Later in this document, we discuss the likelihood of prices being different from $4/Mcf.

We make a general observation here that in several instances we have quoted from EPA and other reports from the recent past. Despite having been published as much as five years ago, these reports are valuable because they provide transparent and well-documented examples of cost-effective and profitable emissions reductions that have been achieved. In contrast, we find in general that the EPA TSD estimates lack transparency. In a few instances, sources for the analysis are not entirely clear. In other instances where sources are mentioned, the additional analysis conducted using those sources are not sufficiently explained to facilitate independent verification. In yet other instances, it is unclear whether some of the estimates are based on past achievements. Additionally, as explained in more detail in following sections, the estimates from past reports provide numerous examples of controls being much more cost-effective than the EPA TSD estimates, suggesting, by contrast, that the latter is conservative.

a. Green Completions

We assess EPA's estimated cost of control of green completions to be reasonably realistic.

Table 4: Cost of control analysis of well completions and recompletions

			#	*$*	*Mcf*	*$ / Mcf*	*$*	*$*	*$ / well*	*Years*	*$ / well*
Source	**Year**	**Type**	**# wells**	**Total cost per well (capital, operational)**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Condens-ate savings**	**Total revenue per well**	**Payback**	**Profit per well**
EPA - NSPS TSD [614]	2008	Min	1	2,418							
EPA - NSPS TSD	2008	Max	1	74,860							
EPA - NSPS TSD	2008	Average	1	29,713	8,258 [a]	4.00	33,032	2,380	35,412	0.84	5,699
EPA,[615]	2005	Min	1	7,000	7,700	4.00	30,800		30,800	0.23	23,800
EPA	2005	Max	1	15,000	7,700	4.00	30,800		30,800	0.49	15,800
Devon Energy [617,618]	2004	Average	~400[b]	8,700	11,740	5.00	58,700		58,700	0.15	50,000
BP [619,620,621]	2007	Average	106	12,264	7,500	4.00	30,000	6,321	36,321	0.35 - 0.70	24,057
Williams [622]	2006	Average	1177	14,444	22,515	4.00	90,059 [c]		90,059	0.16	75,616

EnCana [623]	??	Average	??	??			??		??	< 1.00	190 M + over many wells
Anadarko [624]	2008	Average	613			5.00	??		??		16,803
ICF [625]	2009	Average	??							0.25	

[a] 142.7 tons of methane; production quality natural gas is approx. 83% methane (EPA TSD page 5-16); 0.0208 tons per Mcf
[b] Calculated from estimated average emissions per well, given that total emissions reductions was ~4.8 Bcf in 2005
[c] Scaled down from revenues based on a historically higher natural gas price, assumed to be $6/Mcf

In its NSPS Technical Support Document (TSD)[614], EPA estimates that the average green completion costs about $29,700 per completion, and saves approximately 8,300 Mcf of natural gas per completion (valued at $33,000, at $4/Mcf) and a modest volume of condensates.

Based on recent estimates from select company operations and EPA's 2005 reports of achieved emissions reduction,[615] we estimate that a green completion would typically cost $7,000 - $15,000 per completion. The savings from captured natural gas vary quite significantly among different company reports. We note that the average natural gas savings of 7,700 Mcf of natural gas per well from EPA's 2005 estimates is consistent with the EPA TSD's average savings estimates.

Many different companies[616] have reported profitable use of green completions, although the magnitude of profitability varies:

- In 2004, Devon Energy reported an average incremental cost to perform a green completion of $8,700 per well at its Texas Fort Worth Basin operations. Devon estimated that after paying out this cost, it yielded a profit of $50,000 per well by selling the captured gas to market, estimating that it achieved a total emission reduction of 6.16 Bcf at its operations in year 2005; 78 percent of the methane captured (4.8 Bcf) was attributed to green completion methods.[617,618]
- BP reported an initial investment cost of $1.4 million to purchase a portable three-phase separator, sand trap, and tanks to conduct green completions.[619] By 2005, BP completed 106 wells using this equipment and reported an average gas recovery of 0.35 Bcf/year and condensate recovery of 6,700 bbls/year. The company's investment paid out in nearly two years; thereafter, the equipment

[614] EPA NSPS TSD, pages 4-15 – 4-18.
[615] EPA Natural Gas STAR, *Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas*, November 1, 2005, attached hereto as Exhibit 198. EPA reports costs of $1,000 to$10,000 per well (in November 2005 document). However, the costs use in this report are higher ($7,000 - $15,000 per well), and more conservative, because this data relies on cost estimates provided by Devon, BP and Williams operating experience (in New Mexico).
[616] Some of these individual reports may have been included as part of EPA's industry-wide statistics, but there remains some uncertainty as to whether and how these examples have been assimilated, Therefore these examples serve as specific instances of the successful implementation of these technologies.
[617] EPA, ExxonMobil Production Company, and American Petroleum Institute, Green *Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, September 21, 2004, attached hereto as Exhibit 199.
[618] Devon Energy, *EPA Natural Gas STAR Program Presentation*, March 2007, attached hereto as Exhibit 200.
[619] EPA and Devon Energy, *Reduced Emissions Completions (Green Completions), Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop*, Casper, Wyoming, August 30, 2005, attached hereto as Exhibit 201.

netted a profit of at least $840,000 per year.[620] Later, in 2007, BP reported that green completions had netted a profit of $3.4 million, for an investment of $1.2 million, with a payout of 0.7 years, and a capture of 130 Mt of methane per well.[621]

- Williams reported $159 million in revenue from green completions in its Colorado Piceance Basin Operations from 2002 to 2006, spending $17 million to achieve that revenue, for a net profit of $142 million.[622] Assuming these savings were on average due to a natural gas price of $6/Mcf, the savings have been scaled down for a $4/Mcf price. Williams' economic data was based on 1,177 wells and an average gas recovery of approximately 91 percent.
- EnCana Corporation, the largest natural gas producer in North America, reported results from its Jonah Field in Wyoming. Jonah produces 1.5 percent of United States daily gas needs. EnCana reported[623] that green completion methods were extremely profitable in the Jonah field, yielding a Net Present Value (NPV) of more than $190 million. EnCana's initial investment in the portable REC equipment for the Jonah Field paid out in the first year.
- Anadarko reported an increased operating profit of $10.3 million/year for the period of 2006 to 2008 due to green completions on an average of 613 wells per year. [624] Anadarko based these calculations on a $5/Mcf natural gas price.
- In a 2009 study conducted for New York State, ICF Incorporated found that equipment payouts were as short as three months. ICF also found that companies made more than $65 million in profits when they elected to conduct green completions in 2005.[625]

In sum, our analysis shows that EPA's well profitability and payback assessments are reasonably realistic, even slightly conservative. The TSD has generally slightly higher estimates of the cost of Green Completions than other sources listed in Table 1. The natural gas savings estimates are roughly consistent with other estimates, which in effect include surveys of over 2,000 wells. We underscore that Green Completions are profitable with an average payback of less than one year.

[620] BP's profit was based on gas at $1.99 Mcf and condensate at $22/bbl. Gas and condensate prices are substantially higher in 2010; thus, this is a very conservative profit estimate.

[621] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007, attached hereto as Exhibit 202.

[622] The Williams Companies, "Reducing Methane Emissions During Completion Operations – Economics Volume Recovered." Williams Production RMT – Piceance Basin Operations. 2007 Natural Gas Star - Production Technology Transfer Workshop. September 11, 2007, attached hereto as Exhibit 203.

[623] EPA and ICF International, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009, attached hereto as Exhibit 204.

[624] Methane to Markets, Reduced Emission Completions/Plunger Lift and Smart Automation, Oil & Gas Subcommittee Technology Transfer Workshop, Monterrey, Mexico, January, 2009.

[625] ICF Incorporated, Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program, prepared for New York State, August 5, 2009, attached hereto as Exhibit 205.

b. Low-Bleed Pneumatic Controllers

We assess EPA's estimated cost of control of low-bleed pneumatic controllers to be reasonably realistic.

Table 5: Cost of control analysis of replacing high-bleed pneumatic controllers with low-bleed pneumatic controllers

			#	*$*	*$ / yr*	*Mcf*	*$ / Mcf*	*$ / yr*	*$ / yr*	*$ / yr*	*Years*	*$ / yr*
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annualized cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maintenance, operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [626]	2008	Min	1	158	23[a]							
EPA - NSPS TSD	2008	Max	1	1,852	264							
EPA - NSPS TSD	2008	Average	1	165	24	375[b]	4	1,500		1,500	0.11	1,477
EPA [627,628,629]	2005	Average	1	250[c]	36	180[d]	4	720	1,100	1,820	0.15 - 0.40[e]	1,784
EPA Lessons Learned[630]	2006	Average	1	275[f]	39	125[g]	4	500	50	550	0.50	511
BP [631]	2005	Average	11,500	174[c]	25	296[h]	4	1,183	726	1,909	0.09	1,884

[a] EPA assumes a lifetime of 10 years and a discount rate of 7% (NSPS TSD page 5-16, 5-17)
[b] Using the average value of $ savings (NSPS TSD page 5-16); calculated natural gas volume is consistent with TSD value quoted
[c] Assumes half the value of a retrofit
[d] Based on average natural gas savings of 0.5 Mcf/day (as reported in sources)
[e] Range between calculated value and half the reported value of 9 months for a retrofit
[f] Average of $210 and $340 per device
[g] Average of 50 and 200 Mcf/year
[h] 11,500 wells saved 3.4 Bcf/year

In its NSPS TSD,[626] EPA analyzes the costs for a range of low-bleed and high-bleed pneumatic controllers, and estimates that the average cost of a low-bleed pneumatic controller is $165 more per controller than an equivalent high-bleed pneumatic controller. This is the differential cost of installing low-bleed devices instead of high-bleed devices. EPA also estimates an average of $1,500 per year in natural gas savings from reduced emissions per controller.

Our estimates were based on retrofitting or replacing high-bleed with low-bleed pneumatics, due to the availability of data for these scenarios. These projects would cost more than simply choosing low-bleed equipment instead of high-bleed equipment at a new installation. We assumed that the total cost of retrofitting pneumatics was two times the differential cost of installing a low-bleed device instead of a high-bleed device. In order to facilitate a like-for-like comparison with EPA's estimates, we thus divided the retrofit/replacement costs by two to compare to EPA's figures. This is likely to be a conservative estimate.

Based on EPA reports from 2005, retrofitting a high-bleed pneumatic with a low-bleed pneumatic device costs an estimated $500 per controller on average and has a payback of 9 months. The average annual natural gas savings are about $700, and operational savings are conservatively on average $500 per controller.[627,628,629] Operational savings arise mainly from reduced maintenance costs for low-bleed devices. For instance, high-bleed devices tend to be based on older technology and require more maintenance. Also, if operated in enclosed environments high-bleed devices may present a safety hazard and require regular monitoring. The retrofit or complete replacement of worn units can provide better system-wide performance and reliability, and improve monitoring of parameters such as gas flow, pressure, or liquid level.

An EPA Lessons Learned report from 2006 also reports economics consistent with the above, but with smaller operational and maintenance savings. [630] The EPA TSD's overall economic estimates that are derived from this Lessons Learned document, are more positive than estimates directly from the Lessons Learned document due to updates from vendor research.

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[626] EPA NSPS TSD, pages 5-14 – 5-16.
[627] USEPA and Occidental Oil & Gas Corporation, *Methane to Markets, Methane Recovery from Pneumatic Devices, Vapor Recovery Units and Dehydrators*, October 6, 2005, attached hereto as Exhibit 206.
[628] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.
[629] Journal of Petroleum Technology, *Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005, attached hereto as Exhibit 207.
[630] *Lessons Learned from Natural Gas STAR Partners – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, 2006, attached hereto as Exhibit 208.

BP has reported that it replaced 11,500 high-bleed pneumatic instruments with low- or no-bleed instruments in six states, during the period of 1999 to 2002, capturing 3.4 Bcf/year.[631] The program yielded a net present value of $65 million for a capital investment of $4 million for all 11,500 controllers.

In sum, we find that EPA's cost, cost-effectiveness, profitability and payback assessments are broadly consistent with our estimates, and we consider EPA's estimates to be realistic, so as to support low-bleed pneumatic controllers as the basis for the final performance standards. We note however that our estimates may be slightly conservative as they are based on half the cost of retrofitting or replacement, which is probably higher than the cost of installing a low-bleed device instead of a high-bleed device. Importantly, the data generally supports that replacing high-bleed with low-bleed devices is highly profitable with a very short payback, sometimes within a small number of months.

c. Instrument Air Pneumatic Controllers

We assess EPA's estimated cost of control of conversion to instrument air pneumatic controllers to be conservative. EPA's proposal is better supported than the agency acknowledges.

[631] Gordon Reid Smith, Natural Gas Industry Green House Gas Control & Business Opportunity, Presentation, 2007.

Table 6: Cost of control analysis of replacing high-bleed pneumatic controllers with instrument air pneumatic controllers

			#	*$*	*$ / yr*	*$ / yr*	*$ / yr*	*Mcf*	*$ / Mcf*	*$ / yr*	*$ /yr*	*Years*	*$ / year*
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., operational cost per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annual. profit per year**
EPA - NSPS TSD [633]	2008	Small	1	16,972	2,416[a]	1,334	11,090[b]	871	4	3,484	3,484	(3.27)	(7,606)
EPA - NSPS TSD	2008	Medium	1	73,531	10,469	4,333	36,877	3,658	4	14,632	14,632	(6.24)	(22,245)
EPA - NSPS TSD	2008	Large	1	135,750	19,328	5,999	80,515	10,161	4	40,644	40,644	(6.61)	(39,871)
EPA - NSPS TSD	2008	Simple average	1	75,418	10,738	3,889	42,827	4,897	4	19,587	19,587	(6.03)	(23,241)
EPA NG STAR [628,629]	2005	Average	1	10,000	1,400	7,500[c]	8,900	5,400	4	21,600	21,600	0.70 - 2.00[d]	12,700
EPA Lessons Learned[632]	2006	Average	1	60,000	8,500	17,700	26,200	20,000	4	80,000	80,000	0.96	53,800

[a] EPA assumes a 10-year life, and a 7% discount rate
[b] The total annualized cost includes capital, labor and electrical power
[c] Includes both labor and operational costs such as electrical power (unlike EPA costs above in same column)
[d] Range between calculated value and reported value

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[632] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air,* 2006, attached hereto as Exhibit 208.

In its NSPS TSD,[633] EPA estimates that the capital cost of conversion to instrument air pneumatics, depending on the size, ranges from about $17,000 to $135,000 per controller, along with sizeable yearly maintenance and operational costs. The natural gas savings increase with the size of the pneumatic controller. However, according to the TSD, the savings are not enough to recover the cost of operating and maintaining the devices. As a result, for all device sizes, the devices have a negative annualized profit (which includes the annualized capital cost). Accordingly, EPA states that the investments do not pay back.

This is in contrast to EPA's 2005 assessment based on Natural Gas STAR program experience.[628, 629] There, the average cost of installing an instrument air device was $10,000 with an average $7,500 expenditure in annual maintenance and operations per controller. The average total cost estimate was even smaller than EPA TSD's small-scale device estimates. Also, in proportion to the investment cost, the 2005 EPA estimate of the natural gas savings was much larger in magnitude. Consequently, this rendered instrument air implementation profitable and the investment paid itself back in less than two years.

Similarly, EPA's estimates are in contrast to EPA's Natural Gas STAR Lessons Learned from 2006.[634] In that report, the capital and installation cost of the device was larger at $60,000 per controller. But the natural gas savings were commensurately larger to render the investment profitable with a payback period of about one year. We further note that the EPA TSD based its estimates on the 2006 Lessons Learned document (above). While the cost of implementation estimates are consistent between the two sources, the EPA TSD's revenue estimates are much lower than those in the Lessons Learned document. For instance, the Lessons Learned document estimates average natural gas savings of about 23,000 Mcf/year for medium-sized controllers and about 20,000 Mcf/year on average. In contrast the EPA TSD estimates for medium-sized controllers are 5-6 times lower. The reason for this has not been made sufficiently clear, and EPA must clarify its rationale.

In sum, our analysis shows that the EPA TSD's cost estimates for instrument air pneumatic controllers may have been somewhat overestimated. Also, it is unclear why the EPA TSD's revenue estimates are lower than in other reports. EPA must provide further clarification in both these regards. In the absence of such explanation, we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

[633] EPA NSPS TSD, pages 5-19 – 5-22

[634] *Lessons Learned from Natural Gas STAR Partners – Convert Gas Pneumatic Controls to Instrument Air*, 2006. attached hereto as Exhibit 209.

d. Reciprocating compressors

We assess EPA's estimated cost of control and cost-effectiveness of replacing worn rod packing in reciprocating compressors to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 7: Cost of control analysis of replacing rod packing in reciprocating compressors

			#	*$*	*$ / yr*	*Mcf*	*$ / Mcf*	*$*	*$ / yr*	*Years*	*$ / yr*
Source	**Year**	**Type**	**# devices**	**Total cost per packing**	**Annualized cost of packing**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [635]	2008	Production	1	6,480	2,493	9[a]	4	36	36	180.00	(2,457)
EPA – NSPS TSD	2008	Gathering, Boosting	1	5,346	1,669	396[a]	4	1,584	1,584	3.38	(85)
EPA – NSPS TSD	2008	Processing	1	4,050	1,413	1,077[a]	4	4,308	4,308	0.94	2,895
EPA – NSPS TSD	2008	Transmission	1	5,346	1,669	1,257[a]	-	-	-	NA	(1,669)
EPA – NSPS TSD	2008	Storage	1	7,290	2,276	1,263[a]	-	-	-	NA	(2,276)
EPA – NSPS TSD	2008	Simple average	1	5,702	1,904	296	4	1,186	1,186	4.81	(718)
JPT	2008	Average	1	4,800[b]	1,847[c]	3,504[d]	4	14,016	14,016	0.34	12,169
EPA Lessons Learned Error! Bookmark not defined.	2006	Average	1	6,480[e]	2,493[c]	3,460	4	13,840	13,840	0.47	11,347

[a] EPA NSPS TSD, page 6-15, Table 6-6; based on individual compressor emissions reductions in tons per year
[b] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,200 per cylinder
[c] Using same capital recovery factor as used in the EPA TSD for reciprocating compressors in the production sector (EPA TSD Table 6-2)
[d] Multiplying estimated emissions savings as reported by sources by 4, to account for savings from 4 cylinders

[e] Cost of replacing rod packing for four cylinders (as per EPA TSD estimate of average number of reciprocating compressor cylinders in the production sector, Table 6-2), at $1,620 per cylinder

In its NSPS TSD,[635] EPA estimates that replacing rod packing costs between $4,000 and a little over $7,000 per rod packing replacement. The natural gas savings depends on which stage of the natural gas system the device operates. According to the TSD, the most profitable device is in the processing stage where it has an annualized profit (which includes the annualized capital cost) of about $2,900 per compressor and a payback of 1 year. EPA also found in the TSD that some of the less profitable devices are not profitable enough to pay back even the initial investment.

In our two references, the cost of replacing the rod packing is largely consistent with EPA TSD's estimates. We note that one of the references[636], the EPA Natural Gas STAR Lessons Learned 2006 document, is the same as the one that the EPA TSD states that it obtained its cost estimates from. The other reference[637] notes a slightly lower cost for replacing rod packing.

However, when it comes to annual natural gas revenues from sales, the EPA TSD's estimates indicate that there are almost negligible revenue from the production sector (less than $50), about $1,500 of revenue from the gathering and boosting sectors, about $4,300 of revenue from the processing sector. The rationale for this variation, amongst what appear to be similarly-sized compressors, is not entirely elucidated by EPA. The variation is counter to average industry estimates reported in our references (one of which is even used by the EPA TSD), which do not identify different natural gas revenues in different sectors. Importantly, the natural gas revenues reported in our references is significantly larger than those in the EPA TSD.

As a result, our estimates indicate that replacing rod packing systems in all the three sectors mentioned above would be profitable and have a reasonable cost of control. We note that even the EPA TSD's most profitable compressor (in the processing sector) is much less profitable than our estimates.

In sum, our analysis shows that the EPA TSD's estimates for the cost of replacing rod packing systems are consistent with ours. We request the EPA to further explain why the natural gas revenue estimates are so different in the different sectors and lower on the whole than other references, and to revise its figures appropriately. In the absence of this explanation we consider the overall economic estimates made in the EPA TSD to be potentially conservative.

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[635] EPA NSPS TSD, pages 6-15 – 6-18.
[636] *Lessons Learned from Natural Gas STAR Partners – Reducing Methane Emissions from Compressor Rod Packing Systems*, 2006.
[637] Journal of Petroleum Technology*, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers*, June 2005.

e. Compressors with dry seals

We assess EPA's estimated cost-effectiveness of replacing wet seals in centrifugal compressors with dry seals to be conservative. EPA's proposal is better supported than the agency acknowledges.

Table 8: Cost of control analysis of replacing wet seals in centrifugal compressors with dry seals

			#	*$*	*$ / yr*	*Mcf*	*$/Mcf*	*$*	*$/year*	*$ /yr*	*Years*	*$ /yr*
Source	**Year**	**Type**	**# devices**	**Total cost per device**	**Annual. cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Maint., operational savings per year**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA – NSPS TSD [638]	2008	Processing	1	75,000[a]	10,678[b]	11,527[c]	4	46,108	88,300	134,408	0.56	123,730
EPA – NSPS TSD	2008	Trans. / Storage	1	75,000	10,678	6,372[c]	-	-	88,300	88,300	0.85	77,622
EPA – NSPS TSD	2008	Simple average	1	75,000	10,678	8,949		23,054	88,300	111,354	0.67	100,676
EPA NG STAR [639,640]	2009	Average	1	162,000[d]	23,064[e]	50,000	4	200,000[f]	120,000[g]	320,000	0.51	296,936
Petroleos Mexicanos [641]	2008	Average	1			35,000	4	140,000	??	140,000+	??	126,690
Targa [642]	2006	Average	1	90,000	12,814			??	??	300,000	0.38[h]	287,186

[a] EPA reports this to be 1-3% of the total pipeline cost
[b] EPA assumes a 10-year life and a 7% discount rate
[c] EPA NSPS TSD, page 6-20, Table 6-8; based on individual compressor emissions reductions in tons per year
[d] Assumes half the value of a retrofit
[e] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[f] Conservative low estimate of natural gas savings based on the range of savings from $75,000 - $400,000
[g] Average maintenance and operational savings of $120,000 based on the range of savings of $100,000 - $140,000
[h] Average of 2 – 7 months

In its NSPS TSD,[638] EPA estimates the incremental capital cost of newly installing centrifugal compressors with dry seals instead of centrifugal compressors with wet seals at $75,000 on average. This is the cost of installing a new dry seal compressor instead of a new wet seal compressor. EPA further assumes annual operational savings of $88,300 and additional annual natural gas revenue of approximately $46,000 per compressor from compressors in the processing stage, but no additional revenue in the transmission / storage stage. This is equivalent on average (simple average) to an annualized profit (which includes annualized capital costs) of about $100,000 and a payback period of about 8 months (0.67 years) per new compressor with dry seals instead of wet seals.

According to EPA Natural Gas STAR 2009 reports,[639] a dry seal retrofit (generally more expensive than a new installation) costs $324,000 per compressor on average, with annual operational savings of $100,000 - $140,000 and additional revenues of ranging from $75,000 to $420,000[640] per compressor. A conservative average annual revenue from natural gas of $200,000 per compressor was assumed here. Operational savings are expected from reduced downtime due to less required maintenance, improved compressor reliability, reduced power requirements and elimination of seal oil costs. The average operational savings and additional revenue are noted to be higher than EPA's NSPS TSD estimates. Furthermore, conservatively assuming that the incremental capital cost of a dry seal compressor versus a wet seal compressor is as much as half the cost of a retrofit, the payback period for a dry seal investment instead of wet seal is just over half a year.

In 2008, Petróleos Mexicanos (PEMEX) assessed the benefits of converting from wet seals to dry seals on centrifugal compressors at a compression station in southern Mexico. It found gas savings of 33.5 scfm per seal, and gas savings of 35 MMcf/year, resulting in a profit of $126,690 per year.[641]

Targa Resources and the Gas Processors Association report that replacing a wet seal with a dry seal on a six-inch shaft beam compressor that operates approximately 8,000 hours per year, leaking at 40 - 200 scfm, will pay back in 4 to 15 months, yielding more than $1 million in NPV, assuming a 10 percent discount rate in a span of five years, and

[638] EPA NSPS TSD, pages 6-19 – 6-22.

[639] EPA Natural Gas STAR, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, EPA 430-B-03-012, 2009.

[640] EPA 2011 GHG inventory leak rates: emission estimates used a leak rate of 2125 scfh, (18,600 Mscf/year) equivalent to approximately $75,000 of gas leaking from each compressor each year it is not repaired. EPA estimates that some wet seal compressor leaks can be as high as 200 scfm (105,000); approximately $420,000 of gas leaking from each compressor each year it is not repaired. This assumes a natural gas price of $4/Mcf.

[641] Methane to Markets, Natural Gas STAR International, *Reducing Emissions, Increasing Efficiency, Maximizing Profits*, epa.gov/gasstar/international/index.html, 2008, attached hereto as Exhibit 210.

more than a 170 percent rate of return.[642] The payback period here is for a retrofit. Again, conservatively assuming that an incremental investment in a dry seal compressor is as much as half the cost of a retrofit, the payback period may be expected to halve to 2 – 7 months.

In sum, we consider EPA to have underestimated the average operational savings and the emissions reductions (and so additional natural gas revenue) from the average investment analyzed, leading to conservative cost-effectiveness, profitability, and payback estimates..

f. Tank Vapor Recovery Units

We assess EPA's estimated cost of control and cost-effectiveness of installing tank vapor recovery units to be overly conservative. EPA's proposal is better supported than the agency acknowledges.

[642] Targa Resources and the Gas Processors Association, Methane Savings from Compressors and VRUs, Innovative Technologies for the Oil & Gas Industry: Product Capture, Process Optimization, and Pollution Prevention, July 27, 2006

Table 9: Cost of control analysis of installing vapor recovery units

				$	*$ / yr*	*$ / yr*	*$ / yr*	*Mcf*	*$/Mcf*	*$*	*$ / yr*	*Years*	*$ / yr*	*$ / yr*
Source	**Year**	**Type**	**# dev.**	**Total capital cost per device**	**Annual. capital cost of device**	**Maint., oper. costs per year**	**Annual. total cost of device**	**Volume of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Oper. profit per year**	**Annual. profit per year**
EPA [643]	2008	Average	1	98,186	10,780 [a]	9,367	20,147	291	4	1,164	1,164	negative	(8,203)	(18,983)
EPA NG STAR [644]	2010	Small scale	1	35,738 [b]	3,924 [c]	7,367	11,291	4,566	4	18,262 [d]	18,262	3.28	10,895	6,972
EPA NG STAR	2010	Medium scale	1	55,524	6,096	10,103	16,199	18,262	4	73,048	73,048	0.88	62,945	56,849
EPA NG STAR	2010	Large scale	1	103,959	11,414	16,839	28,253	91,311	4	365,242	365,242	0.30	348,403	336,990
EPA NG STAR	2010	Simple average	1	65,074	7,145	11,436	18,581	38,046	4	152,184	152,184	0.46	140,748	133,603
Anadarko [644]	1999	Average	300										4,167	
ConocoPhillips [644]	??	Average	9	79,167	8,692 [c]							0.33	252,000	243,308
Chevron [646]	1996	Average	8									<1		

[a] EPA assumes a 15-year life and a 7% discount rate

[b] This includes capital cost and installation cost equal to 75% of the capital cost

[c] For annualized capital cost, assumes similar lifetimes and discount rate as in EPA's estimates
[d] Scaled down from savings based on a historically higher natural gas price of $6.22/Mcf

In its NSPS TSD,[643] EPA estimates the capital costs of installing a vapor recovery unit on storage vessels at $98,186, with an additional $9,367 in annual operational and maintenance expenses. According to the TSD, the additional revenue from captured natural gas is $1,164 per vapor recovery unit per year, leading to an annualized loss of $18,893 per unit. Also, due to an annual operating loss on the vapor recovery unit (i.e., operational and maintenance expenses exceed additional natural gas revenue), the TSD concludes that the investment does not pay itself back.

Yet, according to EPA's 2010 report on earnings from Natural Gas STAR programs,[644] vapor recovery projects of various sizes can be profitable with payback periods ranging from a few months to about three years. Natural gas savings were calculated based on a price of $6.22/Mcf; accordingly savings reported here have been scaled down for a natural gas price of $4/Mcf. Even so, we note that even the least-profitable small-scale vapor recovery units generated more revenue from natural gas savings than associated operational and maintenance costs, to yield a net annual operating profit and a consequent investment payback of 3.28 years. Larger tank vapor recovery units had much stronger profitability, with the largest units paying back in 3 - 4 months.

Additional examples of tank vapor recovery profitability include:

- Anadarko reported netting $7 million to $8 million between 1993 and 1999 by installing more than 300 vapor recovery units.[644]
- ConocoPhillips installed vapor recovery on nine tank batteries at a total cost of $712,500. The company's investment paid back within 4 months, earning $189,000 per month thereafter.[645]
- Chevron installed eight vapor recovery units on crude oil stock tanks in 1996; this investment paid back in less than one year.[646]

In sum, we consider EPA's estimates of the cost-effectiveness and profitability of vapor recovery units to be very conservative. In our assessment this is primarily due to the TSD's exceedingly low estimates of natural gas savings from vapor recovery units, which are at least 25 times lower than other reports of vapor recovery units in operation. As we discuss below, these savings are properly considered in the BSER analysis.

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[643] TSD at 7-13 – 7-14.

[644] EPA Natural Gas STAR, *Reducing Methane Emissions with Vapor Recovery on Storage Tanks, Lessons learned from the Natural Gas STAR Program*, Newfield Exploration Company, Anadarko Petroleum Corporation, Utah Petroleum Association, Interstate O&G Compact Commission, Independent Petroleum Association of Mountain States, March 23, 2010, attached hereto as Exhibit 211.

[645] *Id.*

[646] Richards, L.S., Hy-Bon Engineering, Co., *Fundamentals of Vapor Recovery, Associated Gas is Lost Product and Lost Revenue*, October 2005, attached hereto as Exhibit 212.

g. Leak Detection and Repair

We assess EPA's estimated cost of control, cost-effectiveness and profitability of conducting leak detection and repair to be potentially conservative. EPA's proposal is better supported than the agency acknowledges.

Table 10: Cost-effectiveness of leak detection and repair systems

				$	$/year	$ / year	Mcf	$/Mcf	$	$ /yr	Years	$ /yr
Source	**Year**	**Type**	**# devices**	**Total capital cost per device**	**Maint. oper. per year**	**Annual. total cost of device**	**Vol. of saved NG**	**Price of NG**	**Savings of NG**	**Total revenue per year**	**Payback**	**Annualized profit per year**
EPA - NSPS TSD [649]	2008	Valves	1	18,529 [a]	incl. in total	34,608	1,060 [a]	4	4,241	4,241	negative	(30,366)
EPA - NSPS TSD	2008	Connectors	1	9,991	incl. in total	25,622	515	4	2,061	2,061	negative	(23,561)
EPA - NSPS TSD	2008	Pressure Relief Devices	1	101,820	incl. in total	40,372	160	4	639	639	negative	(39,734)
EPA - NSPS TSD	2008	Open ended lines	1	12,280	incl. in total	26,200	693	4	2,772	2,772	negative	(23,428)
EPA - NSPS TSD	2008	Simple average	1	35,655	incl. in total	31,700	607	4	2,428	2,428	negative	(29,272)
EPA Lessons Learned[647]	2003	Gas processing plants	1	59,000 [b]	32,000 [c]	91,000	86,500[d]	4	346,000	346,000	0.19	255,000
EPA Lessons Learned[648]	2003	Compressor stations	1	26,200		26,200	29,400	4	117,600	117,600	0.22	91,400
Methane to Markets	2009	Valves	1	130	??	??	2,895	4	11,580	11,580	likely +ve	likely +ve

647 Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations, 2003
648 Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations, 2003

Methane to Markets	2009	Connectors	1	10	??	??	3,482	4	13,928	13,928	likely +ve	likely +ve
Methane to Markets	2009	Open ended lines	1	60	??	??	2,320	4	9,280	9,280	likely +ve	likely +ve
Methane to Markets	2009	Simple average	1	67			2,899	4	11,596	11,596	likely +ve	likely +ve
Canadian experience	2005	Average	??								+ve	+ve

[a] Average of values from Tables 8-14, 8-15 and 8-17. Table 8-16 data was not included as that was only incremental cost data
[b] Average of $39,000 and $78,000 for repairs annually
[c] Average of $14,000 and $50,000 for leak screening and measurement annually
[d] Average of 45,000 and 128,000 Mcf/year per gas plant

In its NSPS TSD,[649] EPA included comprehensive calculations for the capital and operational cost of conducting leak detection and repair at existing gas processing plants. EPA reports that the annualized cost (including capital) for detecting and repairing leaks, by component, is between $20,000 and $40,000 on average. The savings of natural gas from these repairs is on the order of $1,000 - $4,000. As a result, EPA estimates that leak detection and repair incurs an annual operating loss and accordingly the investments do not pay back.

This is in sharp contrast with EPA Lessons Learned documents for both gas processing plants[650] and compressor stations.[651] In these examples, cost of repairs were between $25,000 and $60,000 per year per facility. For gas processing plants, leak screening and monitoring cost about $32,000 annually per plant. At both gas processing plants and compressor stations, the investments were profitable generating as much as $250,000 in annualized profit per facility, with payback periods of just a few months.

The NSPS TSD estimates are also very different from a 2009 Methane to Markets presentation showing that leak repair can be highly profitable.[652] Given the large differences between EPA and the Methane to Markets capital cost data, it is likely that the cost estimates are not like-for-like. For example, the latter did not include operational and labor costs, and it may have excluded broader system costs. The Methane to Markets presentation also estimates much larger average natural gas savings from discrete repairs, however, which would make detection and repair much more profitable than EPA predicts even when the additional costs are considered.

Additionally, Canadian experience with control of fugitive emissions at oil and gas facilities shows that: most methane leaks are from components in gas service; older facilities have the highest leak rates; about 75 to 85 percent of leaks are economic to repair; and the top 10 leaks at a facility generally contribute more than 80 percent of the emissions.[653]

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[649] EPA NSPS TSD, pages 8-23 – 8-30, mainly Tables 8-14 – 8-17.

[650] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations*, 2003, attached hereto as Exhibit 213.

[651] *Lessons Learned from Natural Gas STAR Partners – Directed Inspection and Maintenance at Compressor Stations*, 2003, attached hereto as Exhibit 214.

[652] Methane to Markets, *Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M)*, Oil & Gas Subcommittee Technology Transfer Workshop, 2009, attached hereto as Exhibit 215. The Methane to Markets Partnership was a collaborative effort among 14 countries to address issues surrounding climate change, methane, and clean energy; the Global Methane initiative, formed by 37 governments and the European Commission in October 2010, builds on the Partnership's work.

[653] Picard, D. (Clearstone Engineering Ltd.), *Cost Effective Opportunities to Reduce Methane Emissions and Losses,* 2005, attached hereto as Exhibit 216.

3. Qualitative considerations of the costs of control technologies

As is apparent from the quantitative analysis presented above, EPA's cost estimates for many of the control technologies are conservative by our assessment, and so underestimate the reasonableness of the cost of control EPA's proposal would require.

We anticipate that some industry commenters may nonetheless contend that these costs must be higher than EPA, or we, have calculated, since those calculations show that some of these measures *save operators money,* yet they have not been universally adopted by operators.

Industry's failure to voluntarily adopt all of EPA's proposed controls does not indicate that the cost of control is not reasonable, or that the control in question is not correctly included as BSER. As explained by the American Petroleum Institute (API), these projects would need to meet internal hurdle rates and compete with core business projects for available capital.[654] Thus, companies may forego even profitable projects in favor of, for instance, new well construction, in the absence of federal regulation requiring them to take action.

For example, if a company has a hurdle rate of 30 percent for making investments, then the control technology would need to be quite profitable to meet this threshold. But this is not the standard for BSER purposes: instead, EPA is only to consider whether costs are truly exorbitant on an industry-wide basis. Therefore, there would be a very large number of projects, even within the Natural Gas STAR partner-companies, that would pose reasonable costs – indeed, in some cases, negative costs -- even while not meeting the likely high hurdle rates for voluntary implementation.

Market failures, in particular "principal agent" problems, can also prevent an industry from undertaking cost-effective measures. Structures of firms may not incentivize managers to undertake measures. Managers may also be quite excessively risk-averse, or simply excessively resistant to new technologies. Finally, managers may lack the necessary information to undertake cost-effective measures.

Moreover, the opinion of experts within the natural gas industry[655] demonstrates that a large number of natural gas companies, especially small to midsize ones, have yet to

[654] American Petroleum Institute (API), and the International Petroleum Industry Environmental Conservation Association (IPIECA), *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, prepared by URS Corporation, March 2007, attached hereto as Exhibit 217, concludes at p. 18 "*Companies and investors operate under capital constrains and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives.*"

[655] Public discussions in June 2011 convened by the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board on natural gas operations, with C-level executives from Chesapeake, Schlumberger, Anadarko, Chevron, ExxonMobil etc.; independent natural gas industry consultants.

update their outmoded practices and embrace a culture of efficiency and corporate responsibility. We therefore consider that significant opportunity to reduce methane emissions exists, especially from small to midsize operations.

Furthermore, the Natural Gas STAR program has about 130 partner companies,[656] with the number of companies in the various stages of natural gas operations being approximately: 30 in production; 10-15 in processing; 35 in transmission; and 55 in distribution. But the number of companies in the US in the various stages of natural gas operations far exceeds this number and is approximately: 6000 in production, 120 in processing; 250 in transmission and storage; 1200 in distribution (and 260 in marketing).[657] While there may be numerous overlaps due to companies operating in multiple stages, even if the total number of unique companies was only 1,500, this figure would still be more than ten times the number of companies participating in Natural Gas STAR. In other words, the number of Natural Gas STAR partner companies is lower than even 10% of the total number of companies. While some number of the remaining 90+% of companies may be smaller operators, they nonetheless would represent a sizeable fraction of natural gas operations. It is quite likely that these companies have not engaged significantly in VOC/methane control activities. As such, we consider that there may be a number of VOC/methane control opportunities, ranging from merely reasonable cost to highly profitable, that remain untapped.

Finally, the general phenomenon of regulation leading to increased productivity within affected firms has been observed in various sectors[658] and is consistent with economic theory.[659]

C. EPA Underestimated Savings Due to Natural Gas Capture Under its Proposal

As noted above, in addition to analyzing costs of implementing the technologies and any operational savings, EPA assessed the additional revenue from natural gas that was not emitted. Regulated entities will directly benefit from this additional revenue, as it will offset the cost of installing controls. As such, these benefits plainly affect "the cost of achieving such reduction" of emissions,[660] and so can and must be included in EPA's cost of control analysis.

[656] EPA Natural Gas STAR: http://www.epa.gov/gasstar/documents/partnerlist.pdf

[657] http://www.naturalgas.org/business/industry.asp#industry; http://www.gpaglobal.org/membership/companies/

[658] Porter, M.E. (1990), *The Competitive Advantage of Nations*, Free Press, New York.

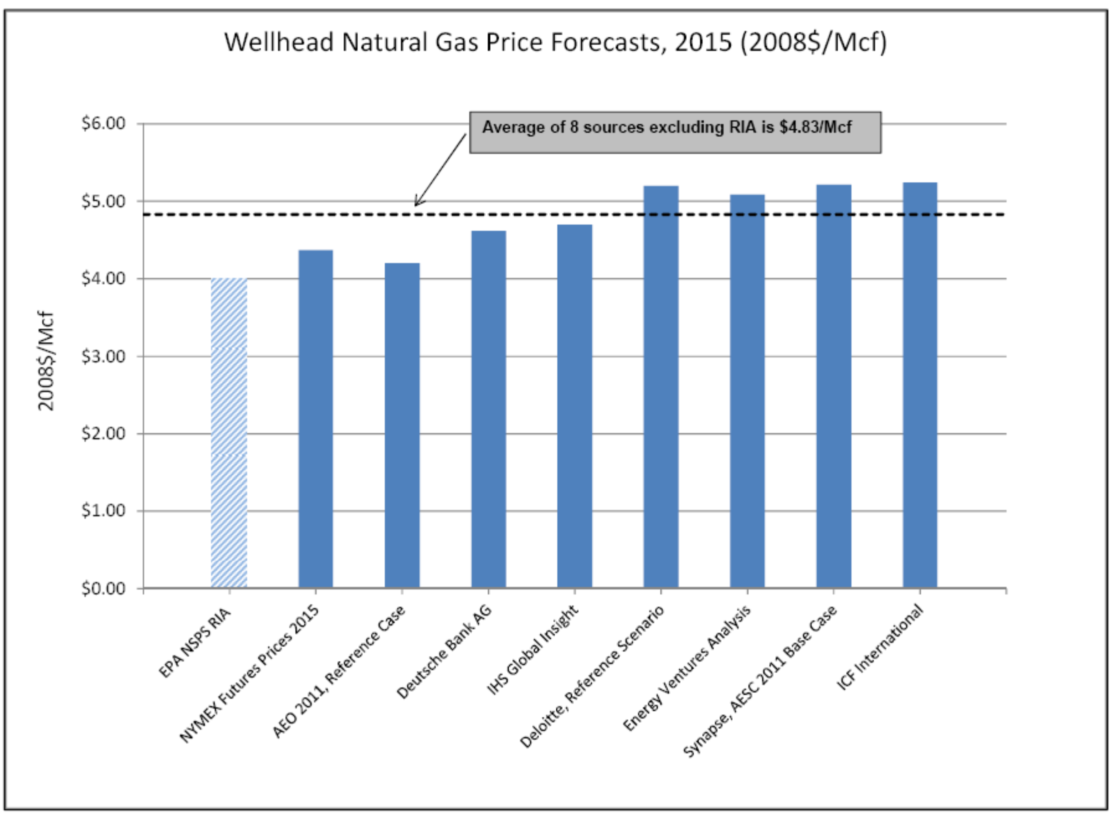
[659] Mohr, R.D. (2002), "Technical Change, External Economies, and the Porter Hypothesis," *J. Environ. Econ. Manag.,* 43, 158-168, doi:10.1006/jeem.2000.1166; Ambec, S., and P. Barla (2002), "A theoretical foundation of the Porter hypothesis," *Econ. Lett.*, 75 (2002) 355–360, attached hereto as Exhibit 218.

[660] 42 U.S.C. § 7411(a)(1).

EPA assumed a $4/Mcf price for natural gas in its revenue calculations. EPA used these calculations in both the RIA and in its BSER determinations themselves.[661] EPA's price assumption is lower than all other projections, including the Energy Information Administration's. EPA must update its calculations to reflect a realistic gas price, using the Energy Information Administration and offering sensitivity analyses for other prices.

According to projections by Synapse Energy Economics submitted as an attachment to these comments, $4/Mcf is a low estimate for future natural gas prices, although it is above current prices. Indeed, this price is lower than $4.22/Mcf price forecast by the Energy Information Administration (EIA). As it turns out, it is lower than *every* other credible natural gas price projection.[662] Synapse concluded that the future price of natural gas was projected to be around $4.8/Mcf in 2015. Notably, prices beyond 2015 are projected to be even higher. Figure 7 below, drawn from that report, shows that some estimates exceed $5/Mcf, and *all* estimates are above EPA's.

Figure 7



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[661] *See, e.g.*, 76 Fed. Reg. at 52,758 (taking cost savings from natural gas capture into account in proposing green completions as BSER).
[662] Synapse used data from eight different sources to conduct its analyses, including from the Energy Information Administration, Deutsche Bank, Deloitte, ICF International and NYMEX.

If EPA used even the EIA projection, it would "double the estimate of net cost savings of the proposed NSPS," going from $45 million to $90 million in savings.[663] If EPA were to use the mean value of all of the above cost estimates, $4.84 Mcf, it would estimate net cost savings of $180 million.[664]

The costs of implementing VOC/methane control technologies are very unlikely to rise as much as 20 percent (which is the relative difference between $4.8/Mcf and $4/Mcf) by 2015. Therefore, based on the higher projected price of natural gas, the economics of the methane control opportunities would become far more favorable. Moreover, the higher natural gas prices rise – recent volatility has seen prices go as high as about $8/Mcf – the more profitable methane control options become.

Recognizing that all forecasts are somewhat subjective, it is clear that EPA's forecast – and its projected cost savings – are systematically low. EPA must, therefore, use the EIA value, at a minimum, and include higher possible wellhead values, as it estimates the savings from the rule to supports its standards-setting analysis. Failure to do so masks the real, and extraordinary, benefits of EPA's proposal.

D. EPA Must Include the Quantified Social Benefits of Methane Reduction, in Addition to Non-Climate related Health Benefits Resulting from Methane Reduction.

According to EPA, the proposed rules, if finalized, would reduce methane emissions by 3.4 million tons per year, resulting in a net annual reduction in total greenhouse gases of approximately 62 million metric tons of CO_2 equivalent (CO_2e).[665] This is a substantial emissions reduction: It is larger than the *total* CO_2e emissions of several industry sectors, and will produce correspondingly large benefits by reducing the powerful climate influence of methane.[666] Although the benefits of this reduction do not speak to the direct cost of the controls required by EPA's proposed standards, and hence are not part of the BSER analysis, they are vitally important to the larger cost/benefit analysis EPA offers in the RIA for the rule. EPA must value them accurately.

EPA tentatively offers quantified co-benefits of between $110 to $1,400 per short ton of methane reduced (depending on discount rate) – for a total of $373 million to more than $4.7 billion[667] - but citing "the uncertainty involved" in the methods it uses,

[663] RIA at 3-19.
[664] Rick Hornby and Dr. Carl Swanson, Synapse Energy Economics, *Estimate of 2015 Natural Gas Wellhead Prices* at 3, attached hereto as Exhibit 220.
[665] 76 Fed. Reg. at 52,792.
[666] *See, e.g.*, EPA, Inventory of U.S. Greenhouse Gases and Sinks (1990-2009), April 2011 at Table ES-2 (noting, for instance, that the total emissions from iron and steel production in 2009 was just 41.9 million metric tons of CO_2).
[667] RIA at 4-32.

"chooses not to compare these co-benefit estimates to the costs of the rule for this proposal."[668]

This is a substantial omission, as it fails to account adequately for one of the most significant benefits of the rule. EPA must not wait to have "interagency accepted monetary values" for the social benefits from methane reduction,[669] before including monetized benefit figures in its RIA. Indeed, E.O. 12866 calls upon the agency to include "quantifiable measures (to the fullest extent that these can be usefully estimated),";[670] E.O. 13563 likewise directs EPA to use the "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible."[671] Neither of these sources permits EPA to wait for interagency agreement before assessing monetized costs.

Because EPA currently has two supportable quantification methods available – direct assessment of the social cost of methane ("social cost of methane method" or "SCM method") and using methane's GWP to calculate CO_2e, then multiplying by the social cost of carbon ("GWP method") – it must use these tools to report a range of monetized benefits for the rule.

As the Ninth Circuit Court of Appeals explained in *Center for Biological Diversity v. NHTSA*, some uncertainty in estimation methodologies does not support declining to quantitatively value benefits associated with reducing climate change pollution at all.[672] Where, as here, "the record shows that there is a range of values [for these benefits], the value of carbon emissions reduction is certainly not zero."[673] Therefore, the agency is obligated to consider such a value, or range of values.[674] Since the agency has a strong quantitative foundation now in the form of two methodologies for estimating the social cost of methane, it should provide monetized benefits using both of these methodologies in its formal cost-benefit assessment (accompanied by an explanation of any limitations and/or uncertainties in each methodology, as necessary).

Finally, EPA must also consider the *non-climate related* health and public welfare benefits of methane reductions. These arise because methane is a significant precursor of surface-level ozone, which causes significant morbidity and mortality and damages crops.

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[668] 76 Fed. Reg. at 52,792-93.
[669] *See* RIA at 4-32
[670] 58 Fed. Reg ____ (October 4, 1993)
[671] (76 Fed. Reg. at 3821 (January 21, 2011)
[672] *See Center for Biological Diversity,* 538 F.3d 1172, 1200 (9th Cir. 2008) (citing Office of Management and Budget Circular A-4 as providing that "agencies are to monetize costs and benefits whenever possible."), attached hereto as Exhibit 221.
[673] *See id*
[674] *See id.* at 1203.

1. EPA has two available methods for monetizing climate benefits from methane reduction.

The Social Cost of Methane Method ("SCM Method"). In Marten and Newbold,[675] the authors directly calculate the social cost of methane using the methodology used by the Interagency Working Group on the Social Cost of Carbon, with some updates. This direct method would be the most straightforward, defensible, and consistent with earlier valuation efforts of greenhouse gases.[676] EPA provides no reason why it cannot do the same here. The agency rejects earlier analyses of the direct social cost of methane, dated from 1994 to 2006, on the basis that "[t]he assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the [integrated assessment models]."[677] However, EPA only cites Marten and Newbold as supporting why the GWP method explored in the RIA may be viewed as a yielding a lower bound for quantified methane benefits,[678] not any reason why EPA cannot use the SCM method. As Marten and Newbold's method is a valid and analytically supportable method, EPA must include figures calculated using their social cost of methane approach.

The GWP Method. The GWP Method consists of converting the methane emission reductions to CO_2-equivalent using methane's global warming potential, then multiplying the resulting CO_2e figure by the social cost of carbon ("SCC"). As noted by Marten and Newbold, this approximation of the climate benefits of methane reductions underestimates benefits at the higher discount rates considered by the interagency SCC group; in one case the underestimate is in excess of 30%.[679] They further note, however, that values of the benefit of methane reductions "estimated using GWPs and the [SCC] will typically have lower absolute errors than default estimates of zero."[680] In other words, using GWP and the SCC to calculate the value of methane emissions reductions is more accurate than not calculating the value of methane reductions, and implying that the value is zero, as EPA has done by failing to compare any value of

[675] Marten, A. L., and Newbold, S. C. (2011), "Estimating the Social Cost of Non-CO2 GHG Emissions: Methane and Nitrous Oxide," EPA NCEE Working Paper # 11-01, available at http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01, attached hereto as Exhibit 222.

[676] We note that not all damages from climate warming (or non-climate damages from methane) are accounted for in any calculation of the SCM because they are not included in the underlying models. However, that the models may pose some uncertainties due to their incompleteness does not mean that EPA can refuse to use them. *See Center for Biological Diversity*, 538 F.3d at 1201-02 (rejecting NHTSA's claim that it did not have to monetize benefits because the models were too uncertain). In addition, the Johnson Report provides comments on how to remedy some of these shortcomings.

[677] RIA at 4-33.

[678] *See id.* at 4-32 (Marten and Newbold "suggest" that the "'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases")

[679] *Id.* at 16. These underestimates can be seen by comparing the SCM, as calculated by Marten and Newbold, with the product of the SCC as they calculated it and a GWP.

[680] Marten and Newbold at 1.

reduced methane emission to the cost of mitigation measures. If EPA is unable to include a directly-calculated SCM in support of the final rule due to methodological problems with the SCM, it must (after identifying and explaining those problems) instead include an estimate of methane-related climate benefits calculated by multiplying SCC by GWP (with an updated GWP as described below).

We note that the flaws and uncertainties in these methods spring from their under-estimation of the true costs of climate change damages, as well as the inherent limitations of attempting to monetize impacts such as human suffering, loss of life, and loss of non-human species. [681] Thus, while they must be considered by definition under-estimates of the true social cost of greenhouse gases, this does not allow the EPA to ignore the existing values entirely, thereby further under-stating the benefits of greenhouse gas reductions.

2. EPA must adjust certain assumptions in the GWP method and the underlying SCC method.

We also attach a detailed discussion by NRDC chief economist Dr. Laurie Johnson of needed adjustments in the GWP method, if EPA uses this approach, as well as in the underlying SCC, regardless of whether EPA includes estimates using the SCM or GWP method (as both the SCM and GWP approaches rely on the methodology of the SCC). This analysis, which we incorporate by reference into these comments, yields several important additional recommendations for EPA's analysis[682]:

First, EPA must use the most recent Intergovernmental Panel on Climate Change (IPCC) GWP values for methane. EPA uses the lower GWP value from the years-old IPCC Second Assessment Report, rather than from the more recent Fourth Assessment Report, because values from the Second Assessment are used in "global GHG inventories" (*i.e.,* produced under the guidelines of the United Nations Framework Convention on Climate Change).[683] Those inventories are not relevant to EPA's goal here, which is to accurately estimate methane benefits, not to report to a "global GHG inventor[y]." That these inventories still use inaccurate conversion values is simply not a justification to undercount methane benefits here.

[681] See, e.g., Ackerman, F, and E. Stanton. 2010. *The Social Cost of Carbon. A Report for the Economics for Equity and the Environment Network*. Available at http://www.e3network.org/papers/SocialCostOfCarbon_SEI_20100401.pdf, attached hereto as Exhibit 223; Ackerman, F. Cost-Benefit Analysis of Climate Change: Where it Goes Wrong, pp.61-81 in Economic Thought and U.S. Climate Change Policy (David. M. Driesen, ed.) MIT Press, 2010.
[682] These recommendations are drawn from pp. 3-4 of Dr. Johnson's report.
[683] 76 Fed. Reg. at 52,793.

Second, even the most recent IPCC GWP from the Fourth Assessment may somewhat undervalue methane's strength as a climate forcer. EPA must, at least, include a sensitivity analysis using the more recent estimate from Shindell et al. of 33.[684]

Third, EPA must provide range of benefits yielded from the various methods and assumptions (c.f. table 1 in Marten and Newbold), as well as a clear, tabular, demonstration of how it has calculated the monetized benefits.

Fourth, as the larger Interagency Working Group on the Social Cost of Carbon continues to improve its calculations, EPA must be sure that these improvements are captured in its analysis here (if they occur during the rulemaking).

3. EPA must also Take Non-Climate Benefits of Reducing Methane Emissions Into Account

Although EPA does not regulate methane as a VOC precursor of ozone,[685] methane is a hydrocarbon which chemically oxidizes in the atmosphere to drive ozone production. While this oxidation is too slow for regional methane controls to substantially reduce ozone levels in that same region, anthropogenic methane contributes significantly to background levels of ground-level ozone around the world. Numerous modeling studies have predicted that reducing methane emissions can significantly reduce surface ozone.[686]

For example, West *et al.* (2006) report that reducing global anthropogenic methane emissions by about 20% would reduce the global average daily 8-hr ozone maximum by over 1 part per billion by volume (ppbv), "in agreement with other models [from other research groups]."[687] The reduction of ozone resulting from methane emissions abatement may be greater in densely populated urban areas, where other pollutants

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[684] D.T. Shindell, G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, S.E. Bauer (2009) "Improved Attribution of Climate Forcing to Emissions," *Science* 326 716-718, attached hereto as Exhibit 224.

[685] 40 C.F.R. §51.100(s).

[686] Fiore, A.M., J.J. West, L.W. Horowitz, V. Naik, and M.D. Schwarzkopf (2008) "Characterizing the tropospheric ozone response to methane emission controls and the benefits to climate and air quality," *J. Geophys. Res.*, 113, D08307, doi:10.1029/2007JD009162, attached hereto as Exhibit 225.; Nolte, C.G., A.B. Gilliland, C. Hogrefe, and L.J. Mickley (2008) "Linking global to regional models to assess future climate impacts on surface ozone levels in the United States," *J. Geophys. Res.*, 113, D14307, doi:10.1029/2007JD008497, attached hereto as Exhibit 226; Dentener, F., D. Stevenson, J. Cofala, R. Mechler, M. Amann, P. Bergamaschi, F. Raes, and R. Derwent, (2005) "The impact of air pollutant and methane emission controls on tropospheric ozone and radiative forcing: CTM calculations for the period 1990-2030," *Atmos. Chem. Phys.*, 5, 1731-1755. Open online access: www.atmos-chem-phys.org/acp/5/1731/, attached hereto as Exhibit 227; Shindell, D.T., G. Faluvegi, N. Bell, and G.A. Schmidt (2005) "An emissions-based view of climate forcing by methane and tropospheric ozone," *Geophys. Res. Lett.*, 32, L04803, doi:10.1029/2004GL021900, attached hereto as Exhibit 228.

[687] West, J.J., A.M. Fiore, L.W. Horowitz, and D.L. Mauzerall (2006) "Global health benefits of mitigating ozone pollution with methane emission controls," *Proc. Natl. Acad. Sciences* (USA) 103, 3988-3993, www.pnas.org/cgi/doi/10.1073/pnas.0600201103 at 3989, attached hereto as Exhibit 229

that catalyze oxidation of methane (e.g. NO_x) are more prevalent. This means that methane reductions will be most effective in reducing ozone in regions which are not in attainment, or are close to non-attainment, for ambient air quality standards for ozone, and where the negative affects of ozone are most acute.

In addition, Wild *et al.* analyzed projections of future emissions for the next several decades and how those emissions will affect surface ozone.[688] Their analysis predicts that global methane emissions will be the most important determinant of whether surface ozone in North America drops over the coming decades, or remains about constant.[689] If ozone remains near present levels, many areas will continue to struggle with attainment of the ambient air quality standard, and as a result public health and welfare will suffer. Their study shows "the increasing importance of limiting atmospheric methane growth as emissions of other precursors are controlled."[690]

Ground-level ozone has significant and well-documented negative impacts on public health and welfare. Some studies have documented how reductions in ground-level ozone resulting from methane emissions reductions in particular will benefit public health and welfare. A global 20% reduction in anthropogenic methane emissions would prevent 14,100 – 40,100 premature deaths in the northern hemisphere.[691]

Using a global value of a statistical life (VSL) of $1 million (substantially lower than the value used by EPA, currently $7.4 million (in 2006 dollars)[692]), West *et al.* calculate a monetized benefit from avoided mortality due to methane reductions of $240 per metric ton (range of $140 - $450 per metric ton).[693]

Ground-level ozone also significantly reduces yields of a wide variety of crops. A recent study finds that in 2000, ozone damage reduced global yields 3.9-15% for wheat, 8.5-14% for soybeans, and 2.2-5.5% for corn, with total costs for these three crops of $11 billion to $18 billion and costs within the US alone over $3 billion (all in year 2000 dollars).[694] Due to the growth in the emissions of ozone precursors in coming years, these crop losses are likely to increase. In 2030, ozone is predicted to reduce global yields 4-26% for wheat, 9.5-19% for soybeans, and 2.5-8.7% for corn, with total costs for

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[688] Wild, O., *et al,* (2011) "Modelling future changes in surface ozone: a parameterized approach," *Atmos. Chem. Phys. Discuss*., 11, 27547–27590. Open online access: www.atmos-chem-phys-discuss.net/11/27547/2011/, attached hereto as Exhibit 230.
[689] Wild *et al.* figures 8 – 10, at 27,586 – 27,588.
[690] Wild *et al.* at 27,549.
[691] Anenberg, S.C., *et al.* (2009) "Intercontinental impacts of ozone pollution on human mortality," *Environ. Sci. & Technol.*, 43, 6482-6487, doi: 10.1021/es900518z, attached hereto as Exhibit 231
[692] http://yosemite.epa.gov/ee/epa/eed.nsf/pages/MortalityRiskValuation.html, attached hereto as Exhibit 232
[693] West *et al.* at 3991.
[694] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296, attached hereto as Exhibit 233

these three crops (2000 dollars) of $12 billion to $35 billion.[695] Another recent study included damage to rice (3-4% reduction in yield for year 2000) and finds even higher total costs for year 2000 ($14 billion to $26 billion).[696] Many other crops are damaged by ozone, so these estimates only capture a portion of the economic damage to crops from ground-level ozone. The value of avoiding a portion of these damages by reducing methane emissions must be considered in valuation of methane reductions.

Avnery *et al*.[697] report work underway to examine the benefits to crop yields from methane mitigation. This study, which will provide an estimate of the value of increased crop yields resulting from avoided ozone damages resulting from methane emission reductions, is currently under peer-review for publication in a scientific journal. We will submit this study as soon as it has been accepted for publication, so that EPA may consider it in order to provide a more accurate valuation of methane reductions.

Damages to human health and crops from ozone produced by methane emissions are independent of damages to human health and welfare resulting from the temperature increases and other negative consequences of climate change due to methane emissions.[698] Thus, a full accounting of benefits from methane reductions must include the sum of the climate-related benefits discussed above and the ozone-related health and crop yield benefits.

VIII. INDUSTRY GROWTH AND RIGOROUS CLEAN AIR REGULATIONS CAN GO HAND IN HAND

Despite the clear economic benefits of EPA's rules, we expect some commenters to argue that the rules will restrain the industry's growth. On the contrary, as we demonstrate below, air quality standards are compatible with successful natural gas expansion efforts.

A. Experience from Colorado and Wyoming, where industry has grown in the presence of strong standards.

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[695] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 2. Year 2030 potential crop production losses and economic damage under two scenarios of O_3 pollution," *Atmos. Env.*, 45, 2297-2309, attached hereto as Exhibit 234.

[696] Van Dingenen, R, F.J. Dentener, F. Raes, M.C. Krol, L. Emberson, and J. Cofala, (2009) "The global impact of ozone on agricultural crop yields under current and future air quality legislation," *Atmos. Env.*, 43, 604-618, attached hereto as Exhibit 235.

[697] Avnery, S, D.L. Mauzerall, J. Liu, and L.W. Horowitz (2011) "Global crop yield reductions due to surface ozone exposure: 1. Year 2000 crop production losses and economic damage," *Atmos. Env.*, 45, 2284-2296.

[698] These negative consequences from emissions of methane, independent of climate change, could be included in integrated assessment models used in the calculation of SCM. However, the model used by Marten and Newbold (see above) does not include these damages, so they must be added to the SCM. If the present benefit of methane reductions is calculated by multiplying the social cost of carbon by a global warming potential (see above) then damages independent of climate change inherently must be added, as that method cannot capture damages independent of climate.

EPA's proposed standards are similar to existing state-level regulations in Colorado and Wyoming, where compliance has not only been accomplished, but has been accompanied by rapid growth in the oil and natural gas industries. As John Corra, Director of the Wyoming Department of Environmental Quality, recently told a Department of Energy advisory panel on natural gas issues, thanks to several years of protective air emission limitations, the number of wells and gas production in active parts of WY have gone up, while air emissions have gone down.[699]

We have examined several metrics illustrating trends in the oil and natural gas sectors which show that both Colorado and Wyoming have experienced growth in those industries while meeting state air regulations, and in some cases, higher growth than both the U.S. overall and other states without such regulations. While this analysis does not quantify the impact of the regulations, (since we do not know what sort of growth these states might have seen in their absence), it does provide evidence that industry can thrive in the presence of these regulations.[700]

B. Regulatory Background in Colorado and Wyoming

Regulations to control emissions of VOCs and HAPs from oil and natural gas operations have been in place in Wyoming for over a decade and in Colorado since 2004. WY first introduced regulations for minor source crude oil, gas, and condensate production sources in October 1995. In 1997, the state lowered the applicability threshold for its minor source permitting program in response to "prospects of increased natural gas development in Southwest Wyoming and other parts of the state."[701] Wyoming promulgated presumptive best available control technology (BACT) guidance requiring oil and gas production facilities to control VOCs and HAPs associated with flashing losses from pressure vessels and storage tanks on January 6, 1999.[702] These requirements applied to new wells and recompletion or stimulation projects. WY subsequently strengthened its BACT requirements, first in August 2001 and again in 2004 and 2007, increasing the source types covered and stringency - with the most recent revision in March 2010. The current presumptive BACT guidance requires differing levels of control of emissions from well completions, pneumatic controllers and pumps, glycol

[699] See video of the July 13, 2011 meeting of the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board; Mr. Corra's presentation starts near the mid-way point. www.shalegas.energy.gov/media/Meeting_071311_Afternoon.html

[700] While this analysis does provide evidence that industry can thrive in the presence of regulation, it is important to understand its limitations. For example, there are a number of additional factors that may contribute to relative growth between states that have not been examined here. These factors include (but are not limited to) the relative potential between states for growth in terms of physical availability or access to resources, as well as general economic health at the local/regional level.

[701] http://deq.state.wy.us/aqd/Oil%20and%20Gas/052297.pdf, attached hereto as Exhibit 236

[702] http://deq.state.wy.us/aqd/Oil%20and%20Gas/oglette.pdf. Although we discuss the substance and effect of Wyoming's presumptive BACT regulations, we do not endorse the presumptive BACT concept as a matter of policy and law.

dehydrators, flash emissions from storage vessels, and separation vessels, depending on the location of the operations. More stringent requirements apply in areas of intense development, e.g. concentrated areas of development and in the immense Jonah and Pinedale Anticline development areas.

Colorado first introduced rules to limit emissions of VOCs and NO_x from oil and natural gas exploration and production facilities in ozone non-attainment (NA) areas in March 2004. Specifically, Regulation No. 7 required control of emissions from condensate operations with the potential for flash emissions, glycol dehydrators, gas processing plants and reciprocating internal combustion engines. In December 2006, Colorado revised Regulation No. 7 to require a greater level of control for condensate tanks located in the Denver metro ozone nonattainment area, and extended controls for dehydrators and condensate tanks statewide. In December 2008, Colorado added a requirement to control emissions from pneumatic devices located in ozone nonattainment and maintenance areas and extended the requirements to control NOx emissions from reciprocating internal combustion engines statewide. In 2009, the Colorado Oil and Gas Conservation Commission (COGCC) promulgated additional rules that have the effect of reducing emissions from glycol dehydrators and storage tanks located in the Piceance basin and well completions and pneumatic devices located statewide. These rules took effect in the spring of 2009.

C. Growth Trends

There are a number of possible metrics that can be used to measure the growth trends in the oil and natural gas industries in these states—we've focused on three data sets: operational rotary rig count, producing natural gas wells, and natural gas gross withdrawals. Data on rig count is from Baker Hughes and is available through 2010; data on gas wells and withdrawals is from the U.S. Department of Energy's Energy Information Administration (EIA) and is available through 2009.

D. Operational Rig Count

The data show that rig counts in Colorado and Wyoming have shown significant growth during the years of regulation, in some cases even higher than other states which do not have such regulations.[703] Colorado's growth has been particularly high, with an average annual growth rate over the 2000-2010 period of nearly 21%, higher than states such as Texas, Oklahoma, New Mexico, and Louisiana (states without similar air regulations) – this figure is also higher than the overall U.S. annual growth rate of about 12%.

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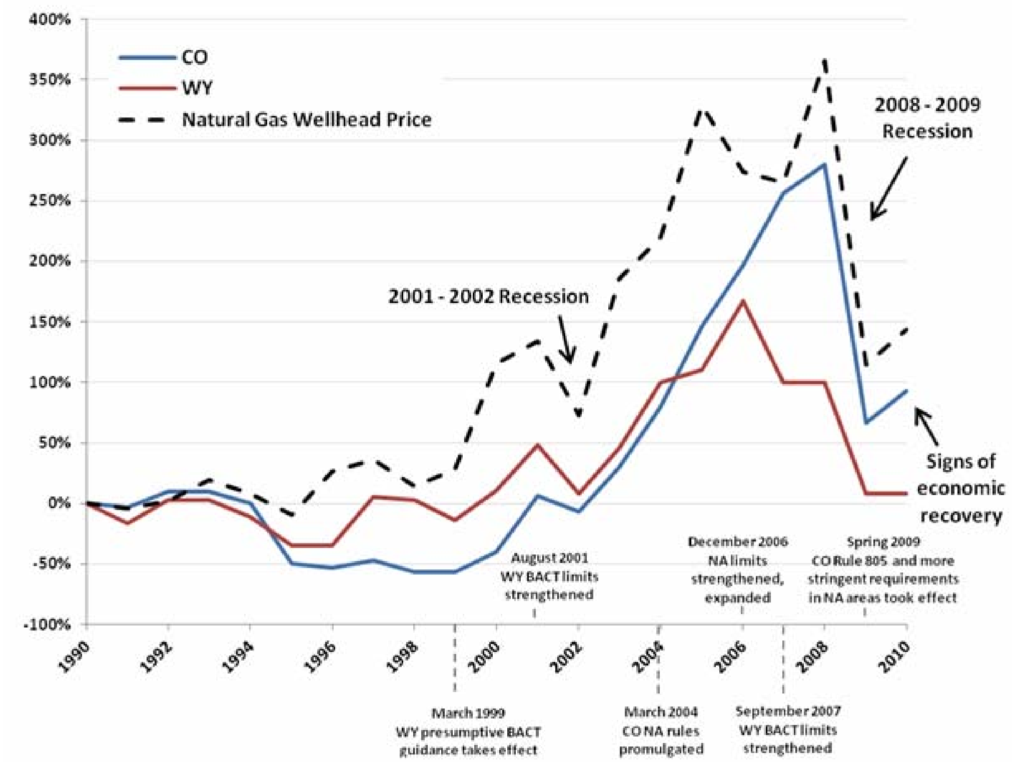
[703] According to Headwater Economics, rig count serves as a good proxy for economic trends, and in particular, employment trends, since the majority of oil and gas industry jobs are associated with the drilling phase. Headwaters Economics, "Drilling Rig Activity Nears Twenty-Year High: Price and Technology Remain Key Drivers of Oil and Gas Drilling Activity", http://headwaterseconomics.org/wphw/wp-content/uploads/RigCounts.pdf (10 June 2011), attached hereto as Exhibit 237.

Colorado's rig count in 2010 was about triple what it was in the year 2000, while overall U.S. rig count did not quite double. The state's rig count growth is particularly high in the few years after 2004, exactly the year that the Regulation No. 7 rules went into effect.

While Wyoming's rig counts decrease following 2006, the data shows a generally increasing trend over the previous ten years during which regulations of some form were in place in the state, suggesting that rig counts are more responsive to factors other than regulation. Indeed, the trend in rig count in both Wyoming and Colorado closely follows that of natural gas prices, and shows notable decreases in the presence of a recession (e.g. 2001-2002, 2008-2009) – factors which appear to impact rig count more than the presence of regulation (see Figure 1). More recently, between 2009 and 2010, Wyoming's rig count leveled out, and Colorado showed signs of recovery, with a 16% increase in number of rigs.

Figure 8: Growth in Number of Rigs in WY and CO and Natural Gas Price Relative to 1990[704]



Sources: Based on rig count data from Baker Hughes[705] and natural gas wellhead price data from EIA.[706]

E. Permit Applications

Industry activity can also be represented through the number of permit applications for oil and natural gas development projects. In WY, for instance, a number of very large oil and gas projects are poised for approval on federal lands. The Bureau of Land Management (BLM) is currently preparing environmental impacts statements for the nearly 9,000-well Continental Divide Creston project, the 4,208 well Hiawatha project, the 1,861-well Moxa Arch project, the 3,500-well Normally Pressured Lance project, and the 838-well LaBarge Platform project.[707] All of these projects are moving forward while in the presence of WY rules regulating emissions from the oil and gas sector.

F. Producing Natural Gas Wells and Gross Natural Gas Withdrawals

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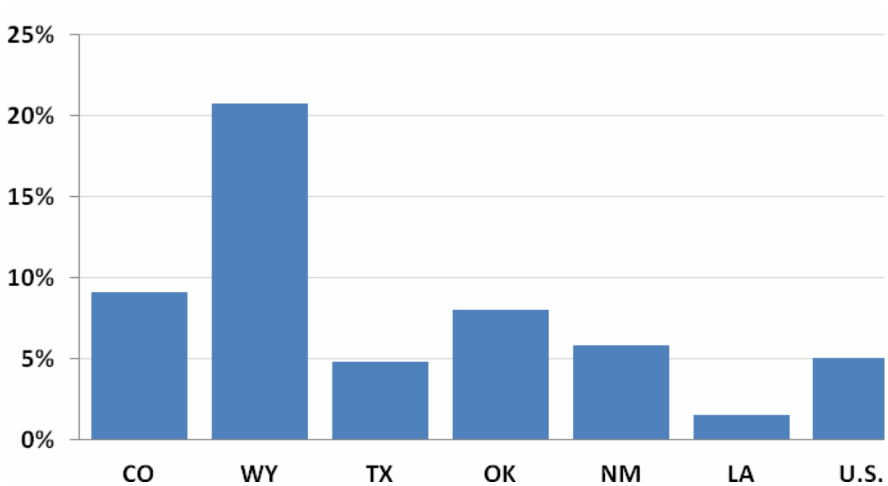
[704] 1990 was selected as the base year, as a year with all data available and early enough to be unaffected by the introduction of the first regulations on the oil and natural gas industries in Wyoming in 1995.
[705] http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm, attached hereto as Exhibit 238.
[706] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm, attached hereto as Exhibit 239.
[707]http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA.Par.24843.File.dat/hot_sheet.pdf, attached hereto as Exhibit 240.

Colorado and Wyoming similarly show strong growth when considering other metrics: producing natural gas wells and gross natural gas withdrawals. In terms of the number of producing gas wells, they show the highest annual growth rates of the states examined with about 9% and 21% average annual growth rates respectively during the period 2000 to 2009, and higher than the average annual growth rate for the U.S. overall at 5% (see Figure 2).[708]

Figure 9: Average Annual Growth of Producing Natural Gas Wells in Selected States and the U.S., 2000-2009



Sources: Based on data from EIA.[709]

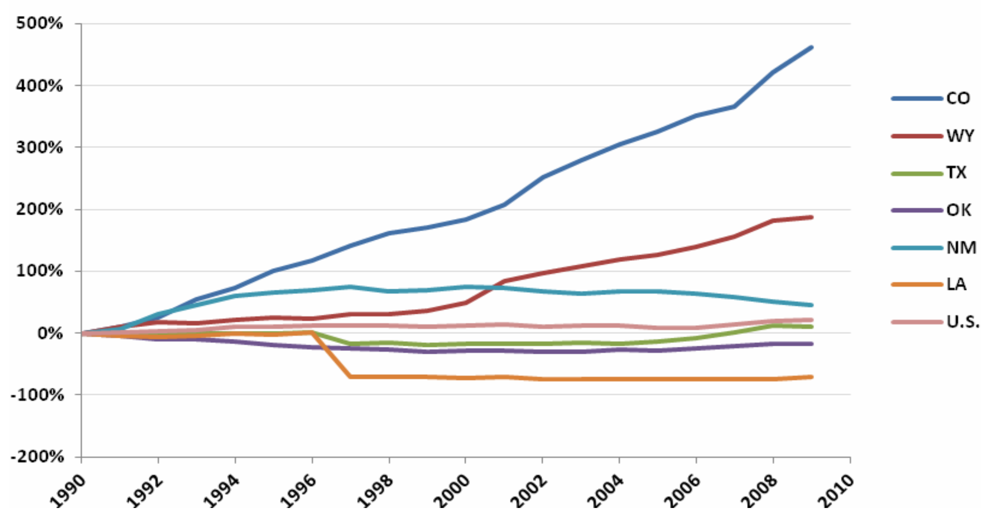
Similarly, the two states also have the highest annual growth rates for gross withdrawals, both with average annual growth rates of about 8% over the same period, and higher than the overall U.S. growth rate of 1%.[710] Figure 3 shows that Colorado and Wyoming experienced more rapid growth in gas production than other selected states without similar regulations as well as the U.S. overall when examining the growth in withdrawals relative to 1990.

[708] Compared to 5%, 8%, 6%, and 2% for Texas, Oklahoma, New Mexico, Louisiana, (all states without similar state regulations), respectively.

[709] http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm, attached hereto as Exhibit 241.

[710] Compared to 3%, 2%, -2%, and -0.1% for Texas, Oklahoma, New Mexico, Louisiana (all states without similar state regulations), respectively.

Figure 10: Growth in Natural Gas Gross Withdrawals in Selected States and the U.S. Relative to 1990



Sources: Based on data from the EIA.[711]

The increase in the economic value of the oil and natural gas withdrawn in these states is also a strong indicator of the economic health of these states' oil and gas industries. For example, in 2010 the total value of taxable minerals in Wyoming was $15.5 billion, up 23% from 2009 and second only to the production value in 2008. The taxable value of oil production in Wyoming was $3.27 billion in 2010, up 34% from 2009, and the taxable value of natural gas production was $7.6 billion, up nearly 30% from 2009. [712]

Again, while we cannot quantify the impact of the regulations in Colorado and Wyoming, the bottom line is that CO and WY have shown considerable growth in these industries throughout the years of regulation—regulation comparable to the EPA's proposed federal rules. EPA's proposed rules therefore are not likely to impair the industry's growth; they will, instead, reduce the environmental impacts of that growth.

IX. EPA MUST PROMULGATE THE FINAL STANDARDS NO LATER THAN APRIL 3, 2012

Some oil and gas industry interest groups have asked EPA to delay implementation of the new source performance standards, in some instances, for up to one year.[713] We strongly oppose such requests. First they are contrary to the statute, which requires new sources on which construction is commenced after the date on which new standards are *proposed* to meet the standards once they begin operations.[714] Furthermore, EPA has already agreed to delay promulgation of the final rule to April 3,

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[711] http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.
[712] http://taxappeals.state.wy.us/2011%20Abstract%20and%20Mill%20Levy%20Report.xls.
[713] For example, in a public announcement describing the rules as "reasonable" API requested an additional year to comply. SNL Daily Dose, Gas Edition, Sept. 28, 2011.
[714] 42 U.S.C. §§ 7411(a)(2), 7411(b)(1), 7411(e).

2012. This delay provides the industry with a full eight months from the time EPA first publicly announced the rules to final promulgation to ensure that new sources will meet the standards once they commence operations. We strongly oppose industry's claim that additional time is needed; indeed, additional time will prolong EPA's violation of its duty to review and revise the standards.

A. The Standards Can and Must Be Implemented Quickly, as a Matter of Law and Practice

As we have noted, standards to reduce air pollution from the thousands of emission points in the oil and gas sector are already long over-due. Under the statute, a review of the NSPS was required over a decade ago.[715] Similarly, a review of the NESHAPs for major sources must have occurred by 2007.[716] Due to EPA's failure to review and revise the current standards, the industry has operated under outdated and insufficient standards for far longer than Congress intended or mandated, at the expense of human health and environmental welfare. Expeditious promulgation of the final rules and compliance therewith is necessary to fulfill EPA's duty to protect human health and the environment.

Futhermore, the standards do not drive the adoption of new or novel control technologies. They largely codify best management practices already in use by many companies and required in California, Wyoming, and Colorado, among other places. Industry can readily implement these standards, even if EPA improves their rigor, as the statute requires and as we discuss above. Moreover, the standards largely apply only to new and modified sources on which construction has not yet commenced, and do not require the cessation of ongoing operations at existing sources. In fact, the only standard that applies to existing sources is the requirement that existing hydraulically fractured wells utilize reduced emission completions during re-completions.[717] Importantly, this requirement does not require an expensive or technically difficult retrofit, either, but rather simply requires that operators utilize the common best management practice of capturing natural gas, rather than venting or flaring it.

B. Even if Additional Delay Were Legally Permissible, It Would Be Unreasonable, as Industry Experience and State Regulation Near-Term Show Compliance Is Possible

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[715] 42 U.S.C. § 7411(b)(1)(B) (requiring EPA to "review and, if appropriate, revise" NSPS "at least every 8 years."). EPA promulgated the existing NSPS for the Crude Oil and Natural Gas Source Category in 1985: "Equipment Leaks of VOCs From Onshore Natural Gas Processing Plants", 50 Fed. Reg. 26122 (June 24, 1985), codified at 40 C.F.R. § 60.630; "Onshore Natural Gas Processing SO_2 Emissions", 50 Fed. Reg. 40158, 40 C.F.R. §60.640 (1985).

[716] 42 U.S.C. § 7412(d)(6) (requiring EPA "review, and revise as necessary" NESHAPs "no less often than every 8 years,"). EPA promulgated the existing NESHAPs for major sources in the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories in 1999: "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage", 64 Fed. Reg. 32610 (June 17, 1999), attached hereto as Exhibit 242.

[717] 76 Fed. Reg. at 52,799-800 (Proposed 40 C.F.R. § 60.5375).

The proposal codifies best management practices and technologies already in use by numerous companies.[718] These requirements are hardly technology forcing, or even novel, and must have come as no surprise to the regulated community—many of whom tout the proposed equipment and work practice standards as models of efficiency and savings. For example, Devon Energy, an operator in the Barnett Shale, reported saving 15.9 Bcf of gas between 1990 and 2007 from its use of reduced emission completions.[719] Devon also reported a $22 million increase in net gas-sale value between 2004 and 2007 due to implementing reduced emission completions.[720] Similarly, as noted at p. XX of these comments, numerous companies including BP, QEP Resources Inc., Shell Upstream Americas, Ultra Petroleum, Devon Energy, and EnCana have replaced high with low or no-bleed pneumatic devices and have realized considerable natural gas and monetary savings.

Colorado and Wyoming have adopted similar rules to those proposed by EPA. Colorado's most recent set of performance standard regulations provided industry five months to comply.

Colorado provided owners and operators of affected oil and gas facilities five months to comply with the state's most recent and comprehensive set of regulations promulgated by the Colorado Oil and Gas Conservation Commission ("COGCC"). These rules, which were adopted on Dec. 11, 2008 by the COGCC, took effect for owners or operators on state lands within four months (by April 1, 2009) and within five months for owners and operators operating on federal lands (May 1, 2009).[721] Like the NSPS, these rules required the use of low or no-bleed pneumatics at exploration and production sites, reduced emission completions statewide and 95% control of VOC emissions from condensate and crude oil storage tanks with the potential to emit ("PTE") 5 tons per year of VOCs located near public places in the Piceance basin.[722]

Colorado's Department of Public Health and Environment ("CDPHE") provided owners and operators of oil and gas facilities used in exploration and production activities less than five months to comply with its most recent rules to limit VOC emissions from oil and gas sources. The CDPHE finalized rules to limit emissions of ozone precursors in December 12, 2008. The rules require owners and operators of *existing* high-bleed pneumatic devices to replace them with low-bleed devices within five months, by May 1, 2009. Owners and operators of new and modified tanks were given until February 1, 2009 to comply with system-wide percentage reduction requirements and all tanks

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[718] See e.g. infra pps xxx (discussion of EPA's consideration of costs).
[719] The American Oil & Gas Reporter, "Reducing Emissions Can Boost Profits", July 2007, http://www.epa.gov/gasstar/documents/aogr_2007.pdf, attached hereto as Exhibit 243.
[720] *Id*.
[721] COGCC Final Rules, Rule 805(b)(2).
[722] *Id*.

associated with new, re-completed or otherwise stimulated wells needed to control VOC emissions by 95% during the first 90 days of production.[723]

As Table 11 shows, Wyoming has required compliance with its presumptive BACT guidance upon the date of final revision or shortly thereafter. We note that we discuss Wyoming's presumptive BACT guidance solely to show what standards are possible, and what compliance times are reasonable. We do not endorse "presumptive BACT" as a legal matter.

Table 11

BACT REVISION	CONTENT	DATE PASSED	EFFECTIVE DATE
1998 revision	Established presumptive BACT requirements for storage tanks and pressure vessels with PTE 40 TPY VOC or more flash emissions	November 20, 1998	March 1, 1999
Chapter 6, Section 2 Permitting Guidance, Revision[724]	Lowered presumptive BACT requirements for storage tanks and pressure vessels to PTE 40 TPY VOC flash emissions and glycol dehydrators with PTE 15 TPY VOCs or 7 TPY total HAP	August 2001	N/A[725]
Jonah and Pinedale Anticline Gas	Lowered emission threshold for	July 28, 2004	Immediately

[723] CO Reg. 7, XII.D.1.
[724] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision http://deq.state.wy.us/aqd/Oil%20and%20Gas/GUIDANCE2001.pdf (August 2001), attached hereto as Exhibit 244.
[725] Wyoming did not publish an effective date on this guidance and conversations with Wyoming DEQ personnel have not been able to confirm a specific date.

Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements[726]	controls of flash emissions to 30 TPY, required quicker installation of flash emission controls and lowered emission threshold for controls on glycol dehydrators to 5 TPY total HAPs.		
Chapter 6, Section 2 Permitting Guidance, Revision[727]	Extended 5 TPY HAP applicability to sources located statewide; lowered applicability threshold for flash emissions to 20 TPY VOCs. Tightened Jonah and Pinedale Anticline requirements.	August 2007	September 1, 2007
Chapter 6, Section 2 Permitting Guidance, Revision[728]	Broadened scope of requirements to apply to greater number of sources and developed tiered	March 2010	August 1, 2010

[726] Wyoming DEQ, Air Quality Division, Revision Jonah and Pinedale Anticline Gas Fields, Addition to Oil and Gas Production Facility Emission Controls and Permitting Requirements, July 28, 2004, http://deq.state.wy.us/aqd/Oil%20and%20Gas/JONAH%20INFILL%20GUIDANCE%20FINAL%207-28-04.pdf., attached hereto as Exhibit 245.
[727] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/AUGUST%202007%20O&G%20GUIDANCE%20-%20FINAL.pdf. attached hereto as Exhibit 246.
[728] Wyoming DEQ, Air Quality Division, Chapter 6, Section 2 Permitting Guidance, Revision, http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf. attached hereto as Exhibit 247.

	level of controls depending on location of source.		

With the exemption of compressors, all of the sources covered by EPA's proposal are currently subject to standards requiring similar levels of control by the states of Wyoming and Colorado. These states required compliance immediately, or in some instances, within months of final rule adoption even where retrofits of existing sources of air pollution were required to meet the standards. Accordingly, eight months is more than enough time for new sources in the oil and gas industry to meet with the new source performance standards. And again, this is particularly true because the standards require demonstrated practices in use by industry and do not require expensive retrofits of existing sources.

X. EPA MUST PROMULGATE AN ENFORCEABLE TIMELINE TO SWIFTLY ADDRESS REMAINING GAPS IN THE NSPS

Just as EPA must implement the standards it has proposed swiftly, it must commit to filling gaps in those standards quickly. As we have described above, the standards suffer from significant gaps, which are contrary to law. They (1) fail to control certain important facility types (such as liquids unloading from wells and heater-treaters); (2) they fail to control certain pollutants (such as PM, methane, and hydrogen sulfide); and (3) they fail to control existing sources. As we have explained, EPA must correct these failings.

That said, we understand that EPA must propose rules to address some of these failures before it can issue final rules, and that EPA must not (and must not) delay finalizing the rules it has proposed. This procedural necessity does not, however, allow EPA to simply avoid complying with its statutory obligations, and certainly does not allow EPA to put off fixing its flawed rulemaking until the next review cycle, eight years from now.

Instead, both to demonstrate that it will comply with the statute, and to provide industry with a clear regulatory calendar, EPA must set out an enforceable schedule, in the final rule issued in April, stating when it will propose, and then finalize, rules addressing each of the illegal gaps in the standards that we have identified.

EPA took precisely this step in its "Tailoring Rule," which sets out how EPA will implement the statutorily-required Prevention of Significant Deterioration program for greenhouse gases. Because EPA was unable to fully implement the program on the statutory timeline, it set out "an enforceable commitment to act" to fulfill its obligations by a date certain.[729] Without excusing its failures here, the agency must do the same,

[729] 75 Fed. Reg. 31,514 31,525 (June 3, 2010); *see also* 40 C.F.R. § 71.13 (codifying this commitment).

setting out a timeline for further action that is substantially shorter than the eight years of the NSPS review period. We ask that EPA complete the remaining rulemaking no later than 2013, which, though countenancing a long and illegal delay, will offer the agency some time to complete its work.

XI. CONCLUSION

Thank you for considering these comments. We look forward to working with EPA to strengthen the proposed rules so that the final rules will better protect communities across the country.

Sincerely,

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[730] With thanks to legal interns Paul Heberling and Jared Fish.

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of: Sabine Pass Liquefaction, LLC and Sabine Pass LNG, L.P	 FERC Docket Nos. CP11-72-000, PF10-24

SIERRA CLUB'S COMMENTS on THE DECEMBER 28, 2011 SABINE PASS LIQUEFACTION PROJECT ENVIRONMENTAL ASSESSMENT

Exhibit 7

Joint Comments on the New York State RDSGEIS (January 11, 2012)

January 27, 2012

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.
[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600’ setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

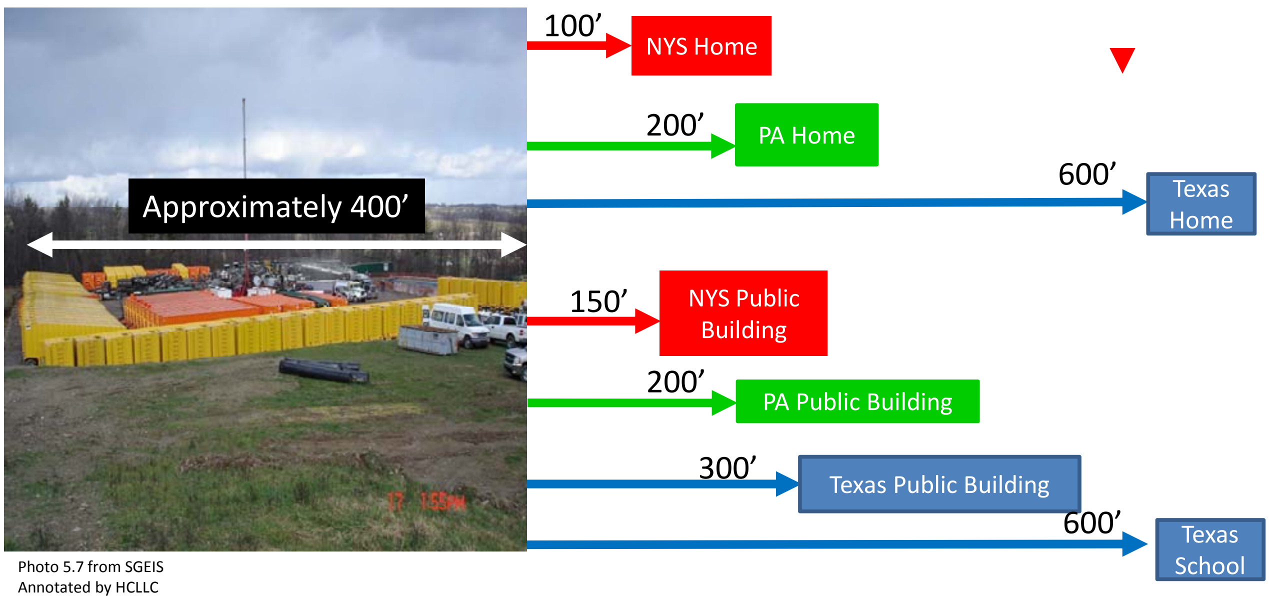

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs

** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (up to 20'-50' wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.