Water Resources and Shale Gas Development

Comments of John Walliser
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to the House Democratic Policy Committee
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Introduction

Chairman Sturla, Representative Vitali, and other distinguished members of the House Democratic Policy Committee, my name is John Walliser and I am a Vice President with the Pennsylvania Environmental Council (PEC). I would like to thank you for the opportunity to discuss water resource protection issues relating to shale gas development in the Commonwealth.

PEC is a statewide nonprofit organization that, for the past four years, has been deeply engaged in policy and outreach efforts related to shale gas development in Pennsylvania – I have included a reference link in my written remarks to our organization's website, which includes the full suite of our reports, testimony, and other statements.[1]

In fact, three years ago I had the privilege of presenting to the Committee on this very same issue. Obviously a lot has changed during this time, and with the implementation of Act 13 of 2012 we are witnessing another sea change to Pennsylvania's regulatory landscape. The good news is that our state has accomplished significant improvements to its management of this industry; but the reality is that there is still much to learn, and issues yet to be resolved.

An extraordinary number of public and private studies are underway to research shale gas development's impact to water and other public resources, including the Environmental Protection Agency's ongoing study of hydraulic fracturing's potential impact on drinking water resources,[2] the National Energy Technology Laboratory's environmental impacts study at well sites in western Pennsylvania,[3] and other academic-driven initiatives in progress throughout the Marcellus and Utica shale plays. The Department of Environmental Protection (Department) is also undertaking two key studies – one on the presence of technologically enhanced naturally occurring radioactive materials (TENORM) in drilling activities and products,[4] and one on air emissions from operations and equipment associated with gas development and delivery.[5]

[1] http://marcellus.pecpa.org/
[2] http://www2.epa.gov/hfstudy
[3] http://www.netl.doe.gov/publications/factsheets/rd/R%26D167.pdf
[4] http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/RadiationProtection/rls-DEP-TENORMStudy-012413.pdf
[5] http://www.dep.state.pa.us/dep/deputate/airwaste/aq/aqm/docs/Long-Term_Marcellus_Ambient_Air_Monitoring_Project-Protocol_for_Web_2012-07-23.pdf

All of these efforts must continue to inform oversight of the shale gas industry, and Pennsylvania must be poised to act swiftly in improving agency authority in light of new information and understanding. PEC has long stressed the importance of adaptive management – no rulemaking or statutory enactment should be viewed as the "final say" – and this holds equally true for Act 13 and its resulting regulatory changes.

With that said, I would like to highlight some of the primary water resource protection issues in light of pending regulations and other initiatives.

Current Water Resources Issues

1. Water Sourcing

Act 13 codified[6] the requirement that operators develop a Water Management Plan prior to operation. This requirement is critical in ensuring that water sourcing for drilling operations will not adversely affect the quality or quantity, including existing and designated uses, of the waters of the Commonwealth. But we must acknowledge that Water Management Plans also place significant demands on the Department, which must ensure that the Plan is accurate and complete, and that compliance is enforced through the life cycle of operations. In the Susquehanna and Delaware River Basins, where Interstate Commissions already have robust programs and staffing in place for this very work, the challenge is minimal. In the Ohio River Basin, however, the Department will bear the weight of monitoring and enforcement – no small task given the size of the basin and current agency capacity. Data from the U.S. Geologic Survey (USGS), Ohio River Valley Sanitation Commission, and other sources will be required to make sound decisions for approval and compliance.[7]

The Department has rightly looked to the Susquehanna River Basin Commission (SRBC) for guidance, and we have urged the Department to fully adopt the framework of SRBC's recently developed Low Flow Protection Policy,[8] which takes a basin-specific, ecologically-driven approach toward decision making on water withdrawals. The Low Flow Protection Policy is based on extensive research performed by The Nature Conservancy,[9] and requires impact assessment and alternative analysis to ensure that withdrawals do not adversely affect headwater or environmentally sensitive stream and river segments.

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[6] 58 Pa.C.S. §3211(m)

[7] The Western Pennsylvania Conservancy and National Science Foundation are independently collecting and aggregating water data for research and monitoring purposes; these efforts will provide tremendous benefit toward protection of water resources.

[8] Low Flow Protection Policy Related to Withdrawal Approvals (Policy No. 2012-01)(December 14, 2012)

[9] The Nature Conservancy, 'Ecosystem Flow Recommendations for the Susquehanna River Basin' (November 2010)

With respect to other potential sources of water, we are also supportive of the Department's recent consideration[10] of allowing the use of abandoned mine drainage as a water supply for hydraulic fracturing. Reducing one of the Commonwealth's largest sources of water pollution to reduce demand on fresh water supplies is a win-win for the Commonwealth. Without question, there are significant concerns and challenges; and while our view is that current legislative and regulatory proposals still fall short of ensuring necessary environmental protections under existing law, we believe this dialog should continue.

2. Water Use in Well Operations

Once water is sourced for hydraulic fracturing, the breadth of well siting and management issues is extensive and beyond the scope of what we can hope to discuss today. Act 13 updated the Oil & Gas Act to achieve many important improvements to water resource protection, but its ultimate effectiveness will depend on regulatory interpretation and implementation. I'd like to touch on a few key issues.

(1) Area of Review
A critical component to the Department's recently published proposal[11] to update regulations applicable to unconventional well sites is what's commonly referred to as "Area of Review". This will require operators to perform more robust well site analyses of subsurface or geologic hazards that may potentially result in migration of gases or well drilling and stimulation fluids. The identification, mitigation and monitoring of features like abandoned wells is a key component of this process. Area of Review analysis has received considerable attention in published Best Management Practice guides and other policy proposals throughout the country,[12] and is of particular importance in Pennsylvania where we have hundreds of thousands of abandoned wells – many of which are unaccounted for. The Department's proposal is a good start, but we believe it should go further to ensure a more comprehensive analysis and proactive mitigation of identified hazards.

(2) Well Siting Setbacks
Act 13 increased presumed well pad setback standards for, among other features, surface waters, water wells, and wetlands. While the new standards are an improvement in most respects from the prior version of the Oil & Gas Act, it fell short of the specific Recommendation[13] of the Governor's Marcellus Shale Advisory Commission Report in two key respects. First, the definition of stream or water body in the Commission Recommendation is broader than the one used in Act 13, which limits this definition to solid blue line streams

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10 http://files.dep.state.pa.us/Mining/Abandoned%20Mine%20Reclamation/AbandonedMinePortalFiles/MIW/Final_MIW_White_Paper.pdf

11 http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/OilGasReports/2012/TAB%20MEETINGS/APR232013/2013-04-23_Ch_78_Subch_C_ANNEX_A_(2013-04-02).pdf

12 PEC first promoted this site review concept in its 2010 Report 'Developing the Marcellus Shale'

13 Recommendation 9.2.24

identified on USGS topographic maps. Second, the Commission's Recommendation also suggested requiring additional setback or best management practices for well sites in proximity to High Quality and Exceptional Value streams.

It should also be noted that these setback standards, along with the local ordinance preemption provisions of Chapter 33 of Act 13, are subject to legal challenge in an appeal before the Pennsylvania Supreme Court. At issue in this particular instance is the scope of the setback waiver authority granted to the Department. Our understanding is that the Department is currently in the process of developing written guidance for issuing waivers to setback standards pursuant to the amended Oil & Gas Act, but of course the utility of this policy will hinge on the Supreme Court's decision.

(3) Impoundment Pits

The Department's regulatory amendment proposal also includes new standards for well pad and centralized impoundments for the storage of fresh and waste water (including flowback and produced liquids). Evolving best management practices for the industry reflect a trend toward both:

- Requiring, in most instances, closed loop systems for all drilling and waste fluids utilized and produced at well sites; and
- Requiring impoundment pits to be double lined with impermeable materials along with real-time leak detection monitoring both up and down gradient from the site.

It is our understanding that the Department is contemplating further revisions to its regulatory proposal to move closer to these criteria, and we strongly support this effort. We also have concerns with proper monitoring and mitigation of air emissions from impoundment pits, particularly centralized storage of waste fluids.

(4) Monitoring and Reporting

Impacts to drinking water supplies continues to be an area of particular concern to landowners and communities, and there remains considerable public uncertainty regarding how baseline water quality information is obtained by individual operators, and what information is subsequently reported by the Department to landowners. Industry associations have begun to develop standards[14] for these processes, and we believe the Department should follow suit by establishing its own guidance for pre- and post-drilling water testing parameters and reporting requirements. In addition, the Department should conduct public outreach on testing requirements and procedures to ensure public confidence in the appropriateness of testing and disclosure.

This issue also points to the need for private water well construction and decommissioning standards; Pennsylvania is one of only two states remaining to not promulgate such standards.

[14] As one example, the standard developed by the Marcellus Shale Coalition can be found at http://marcelluscoalition.org/wp-content/uploads/2013/03/RP_Pre_Drill_Water.pdf

PEC supports legislation[15] introduced this session in the House of Representatives that would accomplish this goal.

(5) Chemical Disclosure
Act 13 made important changes to the disclosure of chemicals utilized in hydraulic fracturing; these changes, at the time of the law's passage, resulted in some of the most proactive reporting requirements in the country. But in little more than a year after enactment, current best management practices[16] now point toward more comprehensive disclosure standards that include all chemicals and drilling fluids utilized by operators and subcontractors on unconventional well sites. We believe this is a timely issue for consideration by the Department and General Assembly.

3. Waste Disposal

(1) Onsite Disposal of Drill Cuttings
With respect to drilling wastes, one ongoing concern is the on-site disposal of drill cuttings after well development activities are complete. The Department's pending regulatory proposal includes new restrictions for on-site disposal of wastes from unconventional operations, and the current TENORM Study will include more complete characterization of drill cuttings. It is worth noting that several unconventional operators are already voluntarily deciding to forgo on-site disposal, opting instead for removal to an approved waste facility – we cannot say, however, whether this is due to logistical considerations like on-site volume capacity, or is based on land or water contamination concerns. Given the long-term implications to landowners and the environment, we believe this issue is ripe for further review by the Department and General Assembly once the Department's TENORM study is complete.

(2) Disposal of Waste Fluids
Act 13 requires operators to track the transport and disposal of wastewater resulting from well development, but submission of that information is left to the discretion of the Department. We believe the Department should require operators to include transport and disposal data in their biannual waste reporting, and should make this information readily available to the public.[17]

Inspection and Enforcement; Agency Capacity

Act 13 contains numerous requirements relating to increased inspection frequency of well sites, as well as more comprehensive public reporting of inspection reports, enforcement activities, and operator compliance. All of these are essential to better understanding the impacts of

[15] House Bill 343 (P.N. 350)
[16] Please see Standards of the Center for Sustainable Shale Development, attached at the end of these comments.
[17] This is consistent with Recommendation 9.2.7 of the Governor's Marcellus Shale Advisory Commission.

shale gas development, and in ensuring both compliance and public confidence in the Department's oversight of the industry.

But we must be honest – this is a tremendous set of responsibilities placed on an agency that has seen its budget and staffing levels decreased by successive Governors and the General Assembly for almost a decade. While the Oil and Gas Program has rightfully been expanded to help meet the challenge, this has come at the cost of other Bureaus tasked with management of shale gas activities – including Air and Water. The Department cannot be expected to do more with less. Passing laws and regulations has less purpose if the agency does not have the means to implement and enforce them. I respectfully ask that you consider this as you listen to the testimony provided today.

Center for Sustainable Shale Development

I would like to bring one other item to the Committee's attention. PEC is a participant in the recently announced Center for Sustainable Shale Development (CSSD) – an independent, collaborative effort that seeks to support continuous improvement and innovative practices for the shale gas industry through public performance standards and third-party certification. I have included a complete copy of CSSD's initial Performance Standards with my written remarks for your review.

CSSD is certainly not meant to displace regulation, but it can serve as an important guidepost for evolving best practices and standards that have been developed by certain members of the industry and environmental community. Many of my comments made here today include principles reflected in the CSSD standards.

Conclusion

In conclusion, I thank you again for the opportunity to comment before the Committee.

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PERFORMANCE STANDARDS
(March 2013)

GEOGRAPHIC SCOPE AND APPLICABILITY OF CSSD PERFORMANCE STANDARDS

These standards apply to unconventional exploration, development, and gathering activities including site construction, drilling, hydraulic fracturing and production in the Appalachian Basin. These regional standards consider geology, topography, population density, infrastructure, surface water, ground water and other issues of particular concern in the Appalachian Basin. Accordingly, until such time as the scope of these standards may be amended, these standards and the CSSD evaluation and certification process will be limited to operators' unconventional activities in the Appalachian Basin.

WATER PERFORMANCE STANDARDS

Goal of Water Standards: The goal of the water standards is that there be zero contamination of fresh groundwater[1] and surface waters.

Wastewater Performance Standards

Performance Standard No. 1: Operators shall maintain zero discharge of wastewater (including drilling, flowback and produced waters) to Waters of the Commonwealth of Pennsylvania and other states until such time as CSSD adopts a standard for treating shale wastewater to allow for safe discharge. Such standard will be adopted by September 1, 2014.

Note: This standard does not apply to nor prohibit disposal of wastewater by deep well injection.

Performance Standard No. 2:

1. Operators shall maintain a plan to recycle flowback and produced water, for usage in drilling or fracturing a well, to the maximum extent possible.

2. Within two (2) years following implementation of these standards [or for each new well that obtains an ESCGP-1 permit, or other earth disturbance permit, following implementation of these standards] Operators must recycle a minimum of 90% of the flowback and produced water, by volume, from its wells in all core operating areas in which an Operator is a net water user.

[1] "Fresh groundwater" is "water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials."

3. CSSD will consider a recycling standard for a net water producer within one year. Operators will maximize the use of recycled water to the extent possible during this time.

Pits/Impoundments Performance Standards

Performance Standard No. 3:

1. After the promulgation date of these standards, any new pits designed shall be double-lined and equipped with leak detection.

2. Operators, within 12 months of implementation of these standards, shall contain drilling fluid, when using oil-containing drilling fluids to drill a well, in a closed loop system at the well pad (e.g. no ground pits).

3. Operators, within 24 months of implementation of these standards, shall contain drilling fluid and flowback water in a closed loop system at the well pad, eliminating the use of pits for all wells.[2]

Performance Standard No. 4:

1. When utilizing centralized impoundments for the storage of flowback and/or produced waters, Operators shall ensure that free hydrocarbons are removed from the water prior to storage and that new impoundments are double-lined with an impermeable material, equipped with leak detection and take measures to reasonably prevent hazards to wildlife. Total hydrocarbons should be substantially removed.

2. Additionally, CSSD will facilitate research designed to determine the extent of hydrocarbon emissions from these waters so that by September 1, 2014, a decision can be made as to whether, and to what extent, this standard should be amended.

Groundwater Protection Performance Standards

Performance Standard No. 5: Operators shall establish an Area of Review (AOR), prior to drilling a well, which encompasses both the vertical and horizontal legs of the planned well. Within the AOR, the operator must conduct a comprehensive characterization of subsurface geology, including a risk analysis, that demonstrates the presence of an adequate confining layer(s) above the production zone that will prevent adverse migration of hydraulic fracturing

[2] *For guidance document:*

Pit – any in-ground impression constructed on a well site that is used for the storage and disposal of residual waste from the development of a natural gas well and subject to 25 Pa. Code, Chapter 78.

Centralized Impoundment – any in-ground impression constructed off of the well site which is used to store and aggregate flowback water for use in the hydraulic fracturing process and subject to 25 Pa. Code, Chapters 78 and 105.

fluids. As part of the risk analysis, and before proceeding with hydraulic fracturing, the operator must also conduct a thorough investigation of any active or abandoned wellbores within such area of review or other geologic vulnerabilities (e.g., faults) that penetrate the confining layer and adequately address identified risks.

Performance Standard No. 6:

1. Operators shall develop and implement a plan for monitoring existing water sources, including aquifers and surface waters [terms to be defined in guidance document] within a 2,500 foot radius of the wellhead (or greater distance, if a need is clearly indicated by geologic characterization), and demonstrate that water quality and chemistry measured during a pre-drilling assessment are not impacted by operations.

2. Operators must conduct periodic monitoring for at least one year following completion of the well. Such monitoring must be extended if results indicate potentially adverse impacts on water quality or chemistry by operations.

3. In the event that monitoring establishes a possible link between an Operator's activities and contamination of a water source, the Operator shall develop and implement an investigative plan and, if a positive link is established, implement a corrective action plan.

4. The testing and monitoring plan should provide for additional monitoring in the event a well is re-stimulated.

Performance Standard No. 7:

1. Operators shall design and install casing and cement to completely isolate the well and all drilling and produced fluids from surface waters and aquifers, to preserve the geological seal that separates fracture network development from aquifers, and prevent vertical movement of fluids in the annulus.

2. Operators will not use diesel fuel in their hydraulic fracturing fluids.

3. Operators will publically disclose the chemical constituents intentionally used in well stimulation fluids. Disclosures will include: information identifying the well, the operator and the dates of the well stimulation; the type and total volume of the base fluid; the type and amount of any proppant; all chemical additive products used in a well stimulation, including the name under which the product is marketed or sold, the vendor, and a descriptor of additive's purpose or purposes (e.g. biocide, breaker, corrosion inhibitor, etc.); the common name and Chemical Abstracts Service registry number for each chemical ingredient used in a stimulation fluid; the actual or maximum concentration of each chemical ingredient, expressed as a percent by mass of the total stimulation fluid. Chemical ingredients should be disclosed in a manner that does not link them to their respective chemical additive products. Disclosure of the above information will be offered to the relevant state agency and will also be posted on FracFocus.org. If an operator, service company or vendor claims that the identity of a chemical

ingredient is entitled to trade secret protection, the operator will include in its disclosures a notation that trade secret protection has been asserted and will instead disclose the relevant chemical family name. Operators will implement measures consistent with state law to assist medical professionals in quickly obtaining trade secret information from the operator, service company or vendor holding the trade secret that may be needed for clinical diagnosis or treatment purposes.

4. CSSD will develop a standard relating to the public disclosure of chemicals other than well stimulation fluids by September 1, 2013.

5. Operators will also work toward use of more environmentally neutral additives for hydraulic fracturing fluid. Mechanical integrity tests shall be performed when refracturing an existing well.

Performance Standard No. 8:

1. Operators shall design each well pad to minimize the risk that drilling related fluids and wastes come in contact with surface waters and fresh groundwater[3].

2. In preparation for any spill or release event, Operators shall prior to commencement of drilling, develop and implement an emergency response plan, ensure local responders have appropriate training in the event of an emergency, and work with the local governing body, in which the well is located, to verify that local responders have appropriate equipment to respond to an emergency at a well.

3. In addition, in the event of spill or release, beyond the well pad, Operators shall immediately provide notification to the local governing body and any affected landowner.

AIR PERFORMANCE STANDARDS

Performance Standard No. 9

1. Beginning on January 1, 2014, in accordance with the conditions set forth in Paragraphs 3 and 4 below, an Operator must direct all pipeline-quality gas during well completion of development wells[4], and re-completion or workover of any well into a pipeline for sales.

[3] Fresh groundwater is defined as water in that portion of the generally recognized hydrologic cycle which occupies the pore spaces and fractures of saturated subsurface materials.

[4] Development wells are wells that are not exploratory or extension wells, as those terms are defined and restricted in Paragraph 6.

2. Any gas not captured and put in the sales pipeline may not be vented[5] and must be flared in accordance with Standard No. 10 below.

3. Acceptable reasons for sending gas to a flare and not directing gas into the sales line include:

(a) Low content of flammable gas. Such low-flammability gas must be directed through a flare, past a continuous flame, to insure combustion begins when gas composition becomes flammable.

(b) For safety reasons.

4. Circumstances unacceptable for sending gas to flare, instead of directing it into a sales line, are:

(a) Beginning on January 1, 2014, a lack of a pipeline connection except for wells that are designated as either exploratory or extension wells using SEC definitions (however, companies should minimize flaring and maximize the use of reduced emissions completions on exploratory or extension wells, where possible);

(b) Inadequate water disposal capacity;

(c) Undersized flow back equipment, lack of flow back equipment or lack of equipment operating personnel.

5. Any upset or unexpected condition that leads to flaring of gas, instead of directing it into a sales line, must be documented and records maintained by the Operator, including a description of the condition, the location, date, and quantity of gas flared.

6. Using the SEC definitions, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. An extension well is a well drilled to extend the limits of a known reservoir. Wells with these designations must be consistent with Operator reporting of such designations to the SEC, if applicable.

Performance Standard No. 10

1. When flaring is permitted during well completion, re-completions or workovers of any well, pursuant to Standard No. 9 above, Operators must adhere to the following requirements:

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[5] For purposes of this standard, venting does not include the de minimis fugitive emissions from gas busters (i.e. that may occur from separator vessels during the initial cleanup period of the well). Immediately upon detection of gas in the flowback, operators must divert the flowback into reduced emission completion ("REC") equipment.

(a) Operators must either use raised/elevated flares or an engineered combustion device with a reliable continuous ignition source, which have at least a 98% destruction efficiency[6] of methane. No pit flaring is permitted.

(b) Flaring may not be used for more than 14-days on any development well (for the life of the well). Flaring may not be used for more than 30-days on any exploratory or extension wells (for the life of the well), including initial or recompletion production tests, unless operation requires an extension.[7] If flaring continues beyond 30-days for an exploratory or extension well, Operators must document the extent of additional flaring and reasons requiring flaring beyond the 30-days.

(c) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours.

Performance Standard No. 11

1. The following standard applies only to nonroad dedicated diesel horizontal drilling rig engines at the wellpad. CSSD encourages and supports the conversion of drilling rig engines to either dual-fuel, electricity or natural gas. The following emissions standards apply to the nonroad dedicated diesel drilling rig engines:

[6] Certification of the 98% destruction efficiency may be obtained through either of the following options: (1) a manufacturer's certification and where operation is in accordance with the manufacturer's specifications and parameters; or (2) where the flares are designed and operated in accordance with the following: (a) meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR § 60.18; (b) if necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible; (c) an infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes; (d) an automatic ignition system may be used in lieu of a continuous pilot; (e) flares must be lit at all times when gas streams are present; (f) fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the sites; and (g) flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of five minutes during any two consecutive hours.

[7] For performance standard 10, the 30-day time limit for flaring was based on West Virginia's rules which allow 30-days of temporary flaring before a permit is required. W. Va. CSR § 45-6-6.1a. Additionally, because all states that have developed a flaring time-limit allow flaring to continue longer than the time limit with approval, certain exceptions to the 30-day time limit were provided in performance standard 10 for emergency and upset conditions and well purging and evaluation tests. These exceptions were based on Wyoming's rules. WOGCC Rules and Regulations, Chapter 3, Section 40. Pennsylvania currently has no regulations addressing flaring directly.

(a) By the promulgation date of these performance standards, operator and contractor nonroad engines shall achieve horse power-hour weighted average [8] site emissions equivalent to U.S. EPA Tier 2 nonroad diesel engine standards or better.

(b) Within 30 months of the promulgation date of these performance standards, 25% of all operator and contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[9]

(c) Within 3-years of the promulgation date of these performance standards, 75% of all operator and contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[10]

(d) Within 4-years of the promulgation date of these performance standards, 95% of operator or contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[11]

(e) All nonroad equipment must use Ultra-Low Sulfur Diesel fuel (15 ppm of sulfur) at all times.

2. The following standard applies only to dedicated diesel fracturing pump engines at the wellpad. CSSD encourages and supports the conversion of fracturing pump engines to either dual-fuel, electricity or natural gas.

[8] Weighted average emissions are based on an annual weighted average using the certified emissions level of each engine (g/bhp-hr), the rated power of each engine (HP), and the run time (hrs) of each engine over the course of the year.

[9] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[10] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[11] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

(a) If the fracturing pump is a nonroad dedicated diesel engine powered solely by diesel fuel, then the following emissions standards apply:

(i) Within 1-year of the promulgation date of these performance standards, operator and contractor nonroad engines shall achieve horse power-hour weighted average[12] site emissions equivalent to U.S. EPA Tier 2 nonroad diesel engine standards or better.

(ii) Within 3-years of the promulgation date of these performance standards, 25% of all operator and contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[13]

(iii) Within 4-years of the promulgation date of these performance standards, 75% of all operator and contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[14]

(iv) Within 5-years of the promulgation date of these performance standards, 95% of all operator and contractor engine utilization (hp) shall comply with U.S. EPA Tier 4 emissions standards for particulate matter (PM).[15]

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[12] Weighted average emissions are based on an annual weighted average using the certified level of each engine (g/bhp-hr), the rated power of each engine (HP), and the run time (hrs) of each engine over the course of the year.

[13] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[14] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[15] Meeting U.S. EPA Tier 4 emissions standards for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

(v) These engines must use Ultra-Low Sulfur Diesel fuel (15 ppm of sulfur) at all times.

(b) If the fracturing pump is powered by a dedicated diesel heavy-duty vehicle engine, then the following emissions standards apply:

(i) By the promulgation date of these performance standards, 50% of the heavy-duty vehicle engines used to power fracturing pumps, must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions.[16]

(ii) Within two years of the promulgation date of these performance standards, 80% of the heavy duty vehicle engines used to power fracturing pumps, must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions.[17]

(iii) These engines must use Ultra-Low Sulfur Diesel fuel (15 ppm of sulfur) at all times.

3. Within 1-year of the promulgation date of these standards, CSSD will develop a standard and implementation date for all other engines located at the wellpad.

<u>Performance Standard No. 12</u>

The following standard is only applicable to compressor engines dedicated to unconventional activities:

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[16] Meeting U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[17] Meeting U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

1. Within one-year of the promulgation date of these standards, existing compressor engines greater than 100 horsepower may not emit more than 1.5 grams of NOx per horsepower-hour.

2. Any new, purchased, replacement, reconstructed, or relocated lean-burn engines greater than 100 horsepower may not emit more than 0.5 g/hp-hr for NOx; 2.0 g/hp-hr for CO; 0.7 g/hp-hr for VOCs.

3. Any new, purchased, replacement, reconstructed, or relocated rich-burn engines greater than 100 horsepower may not emit more than 0.3 g/hp-hr for NOx; 2.0 g/hp-hr for CO; 0.7 g/hp-hr for VOCs. Note: This standard will be updated to reflect any future determinations from regulatory agencies with regard to the NOx limitation.

Performance Standard No. 13

By October 15, 2013, all (existing or new) individual storage vessels at the wellpad with VOC emissions equal to or greater than 6 tpy must install controls to achieve at least a 95% reduction in VOC emissions.

Performance Standard No. 14

This standard is applicable to new and existing equipment dedicated to unconventional activities unless stated otherwise.

1. Change rod packing at all reciprocating compressors (both existing and new), including those at the wellhead, either every 26,000 hours of operation or after 36 months.

2. By October 15, 2013, pneumatic controllers (both existing and new) must be low – bleed, with a natural gas bleed rate limit of 6.0 scfh or less, or zero bleed when electricity (3-phase electrical power) is on-site.

3. New centrifugal compressors may not contain wet oil seals. Operators must replace worn out wet seals on existing centrifugal compressors with dry seals.

4. Within 1-year of the promulgation date of these standards, Operators will implement a directed inspection and maintenance program (DI&M) for equipment leaks from all existing and new valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, tanks and other process and operation components that result in fugitive emissions. Process components subject to DI&M are monitored by a weekly visual, auditory, and olfactory check, and once a year by a mechanical or instrument check to detect leaks. Once significant leaks are detected, they are required to be repaired in a timely manner.

5. Eliminate VOC emissions associated with the prevention of well-bore freeze-up (only de minimis emissions are permitted).

6. Existing and new compressors are required to be pressurized when they are off-line for operational reasons in order to reduce blowdown emissions.

Performance Standard No. 15

1. Within one-year of the promulgation date of these performance standards, 80% of all trucks used to transport fresh water or well flowback water must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions.[18]

2. Within 3-years of the promulgation date of these performance standards, 95% all trucks used to transport fresh water or well flowback water must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter emissions.[19]

3. All on-road vehicles and equipment must limit unnecessary idling to 5 minutes, or abide by applicable local or state laws if they are more stringent.

4. All on-road and non-road vehicles and equipment must use Ultra-Low Sulfur Diesel fuel (15 ppm of sulfur) at all times.

[18] Meeting U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.

[19] Meeting U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions may be accomplished by retrofitting with technology on the current Verified Retrofit Technologies List for U.S. EPA or the California Air Resources Board (CARB), which is capable of achieving at least an 85% reduction in PM emissions, and which is installed and operated according to the conditions of the U.S. EPA or CARB verification protocols.