40 CFR Part 60 Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution
August 2014

The USEPA finalized the New Source Performance Standard (NSPS) for the oil and gas (O&G) industry effective October 15, 2012. The regulations are found in 40 CFR Part 60 Subpart OOOO. The regulations apply to certain O&G air emission sources constructed, modified or reconstructed after the August 23, 2011, proposal date. The USEPA is the enforcement agency unless enforcement is delegated to a state agency.

The USEPA published a proposed changes to the rule on July 1, 2014. No substantial changes proposed.

The table below summaries the list of facility types and emission sources affected by the rule.

	Affected Air Emission Source Types						
Facility type	Hydraulically Fractured Gas Wells	Pneumatic Controllers	Recip. Compressors	Centrifugal Compressors – Wet Seals	Storage Vessels	Equipment Leaks	Gas Sweetening Units
Production	✓	✓			✓		
Production Gathering		✓	✓	✓	✓		
Nat. Gas Processing		✓	✓	✓	✓	✓	✓
Transmission					✓		
Gas Storage					✓		

The rule's emission standards include the following with exemptions allowed for safety and other reasons.

NSPS OOOO Affected Facility	Emission Standard	Compliance Date
Group 1 Storage Vessels Emitting $\geq$6 tpy VOCs	95% reduction of VOC	April 15, 2015
Group 2 Storage Vessels Emitting $\geq$6 tpy VOCs	95% reduction of VOC	April 15, 2014
Hydraulically Fractured Gas Wells Completed Prior to January 15, 2015	Completion combustion	October 15, 2012
Hydraulically Fractured Gas Wells Completed on or After January 1, 2015 (with exceptions)	Reduced emission completion (REC)	After January 1, 2015
Centrifugal Compressors with Wet Seals	95% reduction of VOCs	October 15, 2012
Reciprocating Compressors	Replace rod packing every 26,000 hours	October 15, 2012
Pneumatic Controllers Between Wellhead and NG Processing Plants	$\leq$6 scfh bleed rate	October 15, 2013
Pneumatic Controllers at NG Processing Plants	0 scfh bleed rate	October 15, 2012
Equipment Leaks at Natural Gas Processing Plants	LDAR program	October 15, 2012
Sweetening Units at Onshore Natural Gas Processing Plants	Rule specified SO_2 emission	October 15, 2012

Once an emission source is considered an affected source, the affected source is always subject to the rule. Also sources that are exempt (e.g., based on date of construction), can retain exemption status (even if moved to another location) provided it has not been modified or reconstructed as defined in 40 CFR 60 Subpart A.

Storage Tanks

Applicability

Storage vessels (tanks) used to store crude oil, intermediate hydrocarbon liquids, condensate or produced water are subject to the rule if installed after August 23, 2011, and have potential VOC emissions of 6 or more tons per year (tpy).

The rule exempts process vessels (such as vapor recovery towers), surge control vessels, knockout vessels. Also exempt are temporary tanks onsite for less than 180 days and pressure vessels designed to operate in excess of 15 psig with no emissions.

Natural gas from a storage vessel that is recovered by a vapor recovery system and routed to a process does not count toward the 6 tpy VOC limit. Such vapor recovery systems are considered a part of process and not emission controls.

VOC emissions are determined on a per tank basis. Flash, breathing and working VOC losses are to be allocated to each storage tank based on actual operation and production to the storage tanks.

Storage tanks that have potential to emit VOC emissions to less than 6 tpy in a practically enforceable air permit can exempt the tanks from emission control requirements.

Initial Notification

There is no initial notification to USEPA required for Group 2 affected storage vessels.

Emission Standards

The rule has two categories of storage vessels:

- Group 1 storage vessel – storage tanks constructed, modified or reconstructed after August 23, 2011, and on or before April 12, 2013
- Group 2 storage vessel – storage tanks constructed, modified or reconstructed after April 12, 2013

Group 1 Storage Tank Emission Standards/Requirements

Group 1 storage tanks that emit 6 or more tpy VOC are required to:

- Determine VOC emissions by October 15, 2013
- Notify USEPA or state regulatory agency by January 15, 2014, of the location of Group 1 storage tanks
- Control storage tank VOC emissions by 95.0% or greater prior to April 15, 2015

Group 2 Storage Tank Emission Standards/Requirements

Group 2 storage tanks that emit 6 or more tpy VOC are required to:

- Determine VOC emissions within 30 days of beginning operation
- Control storage tank VOC emissions by 95.0% or greater prior to April 15, 2014, or within 60 days after startup, whichever is later

Removal of Emission Controls Allowance

If a storage tank's uncontrolled actual VOC emissions decrease to less than 4 tpy for at least 12 consecutive months, the facility can remove the controls. To demonstrate that tank VOC emissions remain below 4 tpy, a monthly calculation of uncontrolled VOC emissions is required afterwards.

For such storage tanks, the emission controls must be re-installed if one of the following occurs:

- A well feeding an affected storage tank undergoes fracturing or refracturing. If this occurs, the facility must reduce VOC emissions by 95.0% at time liquids from fractured/refractured well are sent to storage tank.

- Monthly emissions calculation indicates tank VOC emissions are 4 tpy or more and the increase is not related to fracturing or refracturing a well feeding the storage tank. Emission controls are then required within 30 days of the monthly calculation.

Storage Tank Emission Controls
Emission controls used for storage tanks typically include vapor recovery systems, enclosed combustion devices (ECD) and flares.

A vapor recovery system that conducts recovered vent gas back into the process (not released to the atmosphere) can be considered process equipment and not an emission control device. Natural gas recovered by the vapor recovery system does not count toward the potential to emit VOC emissions from the storage tank.

Tank covers (e.g., thief hatches) and the closed vent system piping that routes gas to the emission control device (ECD, flare) are considered a part of the emission control system. Each affected storage tank thief hatch must be weighted and properly seated. Use gasket material based on composition of the fluid in the storage vessel and weather conditions.

Flares (Candlestick)
Flares, also called candlestick flares are open flame, thermal oxidation devices that do not include an enclosure around the flame.

Requirements for flares used to control storage tank VOCs include:
- Requirements in 40 CFR Part 60.18(b) Flares
- Operate in a leak free condition and no detectable emissions – including the closed vent system
- Monitoring device that continuously indicates the presence of a pilot flame while emissions are routed to the flare
- Operate with no visible emissions – no smoking or soot

There is no requirement to conduct a manufacturer's performance test for candlestick flares.

Enclosed Combustion Devices (ECD)
Enclosed combustion devices (ECD) are combustion devices that have an enclosure for the flame. These devices are not considered flares and have different requirements from flares.

Enclosed combustion devices used to control storage tank VOCs requirement include:
- Operate in a leak free condition and no detectable emissions – including the closed vent system
- Monitoring device that continuously indicates the presence of a pilot flame while emissions are routed to the flare
- Operate with no visible (smoke/soot) emissions
- For manufacturer tested ECD, operate at an inlet gas flow rate equal to or less than the maximum specified by the manufacturer

Manufacturer Tested Enclosed Combustion Devices (ECD)
Manufacturers of enclosed combustion devices have the option to test each model based on the model's maximum inlet gas volume and BTUs to be combusted. The performance testing procedures are given in 40 CFR 60.5413(d).

Manufacturers can submit the performance test results to USEPA for review and approval of performance test results. A listing of tested ECDs meeting the USEPA's performance testing requirements will be posted the USEPA's webpage.

Tanks Covers and Closed Vent Systems (CVS)
All access hatches, sampling ports, pressure relief valves and gauge wells must form a continuous impermeable barrier over the entire surface area of the liquid in the storage tank and operate with no detectable emissions.

The cover opening must be secured in a closed, sealed position (e.g., gasketed lid) except when opened for sampling, inspecting, repair, etc.

The current rule requires the thief hatch to be weighted and properly seated with the proper gasket material. Proposed changes to NSPS OOOO published in July 2014, will allow other mechanisms besides weighted lid thief hatches. This includes spring loaded hatches or comparable to ensure that the lid remains properly seated.

Bypass Alarm
Facility must properly install, calibrate, maintain, and operate a flow indicator at the inlet to any bypass device that could divert the stream away from the control device or process to the atmosphere. Bypass flow indication should sound an alarm that notifies the field operator when the bypass device is open to the atmosphere.

Monitoring for Flares and Untested ECDs
For each combustion device (flare and untested enclosed combustion devices) conduct monthly inspections the following listed below.

- Visually inspect to confirm pilot is lit when vapors routed to combustion device and that the continuous burning pilot flame is operating properly.
- Monitor combustion device for visible emissions using USEPA Method 22.
- Conduct system integrity checks using olfactory, visual and auditory inspections.
- For any absence of pilot flame, or other indication of smoking or improper equipment operation (e.g., visual, audible, or olfactory), return equipment to proper operation as soon as practicable after the event occurs.

Monitoring for Manufacturer Tested ECDs
For each enclosed combustion device tested by the manufacturer must:

- Ensure inlet gas flow rate equal to or less than the maximum specified by the manufacturer
- Ensure a pilot flame is present at all times of operation
- Conduct system integrity checks using olfactory, visual and auditory inspections
- Conduct quarterly visible emissions testing using USEPA Method 22 for a 1-hour period
- For any absence of pilot flame, or other indication of smoking or improper equipment operation (e.g., visual, audible, or olfactory), return equipment to proper operation as soon as practicable after the event occurs.

Annual Reporting
The first annual report for Group 1 and 2 storage tanks was due January 15, 2014, for the reporting period ending on October 15, 2013. Annual report contents include identification, location, emission rate, deviation report, statement of compliance and any removed from service storage vessels. Consult the rule for details on report content.

Annual reports for affected emission sources are due by January 15 each year for the previous reporting period. Depending on the state agency, Title V permitted facilities may include the NSPS OOOO required report in the Title V annual reports.

For all annual reporting, a certification by a responsible official of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping
Consult the rule’s list of recordkeeping requirements to ensure compliance.

Hydraulically Fractured Gas Well Completions

Affected Wells
Gas well completions with hydraulic fracturing occurring after August 23, 2011, are required to comply with the rule requirements. At this time, the rule does not cover oil wells.

Required Initial Notification
Owners of hydraulically fractured gas wells are required to notify the USEPA or state regulatory agency in writing or electronic format (online system, email) no later than two (2) days prior the completion operation. Some state agencies have online forms to submit the required data. Consult the rule for notification content.

Emission Standards for Hydraulically Fractured Gas Well Completions
October 15, 2012, through December 31, 2014
Use a completion combustion device to combust flowback natural gas or recover the flowback natural gas using a reduced emission completion (REC) system. The rule has exemptions allowing venting from wildcat, delineation and low pressure wells, safety reasons or if prohibited by state or local regulations.

Completion combustion devices used for completion flowback gas are not considered flares or enclosed combustors devices (ECD). Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

Starting January 1, 2015
Reduced emission completions (REC) are required for affected well completions beginning January 1, 2015. The REC should capture the flowback gas after fracturing or refracturing so that the gas is not directly released to the atmosphere. The REC system should route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into a well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve.

RECs are not required for wildcat wells, delineation wells, low-pressure wells and safety considerations. Operator required to use combustion completion device during for flowback gas unless combustion is a safety hazard.

Dates
Each well completion operation with hydraulic fracturing begun prior to January 1, 2015, can use of a completion combustion device or a reduced emission completion (REC) – with exceptions for wildcat, delineation and low pressure wells.

For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, required to use a reduced emission completion (REC) – with exceptions for wildcat, delineation and low pressure wells.

Annual Reporting
Annual reports for affected emission sources are due by January 15 each year for the previous reporting period. Consult the rule for details on report content.

For all annual reporting, a certification by a responsible official of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping
Consult the rule for details on recordkeeping required.

Pneumatic Controllers

Affected Pneumatic Controllers

The rule applies to individual, continuous bleed, natural gas pneumatic controllers if constructed, modified or reconstructed after August 23, 2011.

Pneumatic controllers affected include those in the oil and gas production segments (between the wellhead to natural gas processing plant and well head the point of custody transfer to an oil pipeline).

Continuous bleed, natural gas controllers used oil and gas production facilities with a gas bleed rate greater than 6 standard cubic feet per hour (scfh) are affected sources. The rule also has standards for pneumatic devices at natural gas processing plants.

Exemptions are allowed for high bleed pneumatic controllers for safety considerations. Pneumatic controllers in stock and ordered prior to August 23, 2011, are exempt from the rule.

The rule does not apply to compressed air supplied pneumatic controllers.

Required Notification of Installation

There is no requirement to notify USEPA of the installation of affected pneumatic controllers.

Emission Standards

After October 15, 2013, each affected continuous bleed pneumatic controller that was constructed, modified or reconstructed on or are required to meet a bleed rate equal to or less than 6 scfh when used in the oil and gas production segments.

Affected continuous bleed controllers at natural gas processing plants are required to meet a bleed rate of 0 scfh.

Exemptions are given based on functional needs, including response time, safety and positive actuation.

Dates

Effective October 15, 2013, new continuous bleed controllers installed and operated for facilities between wellhead and natural gas processing plant or oil pipeline installed must have bleed rates less than or equal to 6 scfh.

Effective October 15, 2012, continuous bleed controllers at natural gas processing plants must be zero (0) bleed rate.

Annual Reporting

Annual reports for affected emission sources are due by January 15 each year for the previous reporting period. Consult the rule for details on report content.

For all annual reporting, a certification by a responsible official of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping

Consult the rule’s list of recordkeeping requirements to ensure compliance.

Centrifugal Compressors Using Wet Seals
The rule applies to centrifugal compressors using wet seals installed after August 23, 2011. The rule only applies to the compressor wet seals and does not apply to the engine or motor driver. Centrifugal compressors using dry seals are exempt.

A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site is not an affected source. This would correspond to a “production facility.” Operators commonly consider the affected compressors as operating at “gathering facilities.” There is no definition in the rule of a “gathering facility.”

Relocated compressors that are moved to a separate facility owned and operated by the same company are not affected facilities unless modified or reconstructed as defined under 40 CFR 60.14 and 60.15.

Emission Standard
Reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 % or greater. Emission controls were required to be operating as of October 15, 2012, or upon startup.

Notification of Installation
Facilities are required to notify USEPA or state authority that an affected centrifugal compressor that was constructed, modified or reconstructed on or after October 15, 2012. The initial notification report is no later than 30 days after the affected date. Facilities also must submit a notification of start-up to USEPA/state agency of the within 15 days of startup.

Emission Control Methods
Emission controls used include vapor recovery systems, flares and enclosed combustion devices (ECD). Wet seal fluid degassing system requiring controls must have a cover and use a closed vent system to route the gas to the control device.

Flares must meet 40 CFR 60 Subpart 60.18. No performance testing required for flares.

Enclosed Combustion Device Performance Testing
All ECDs used to control wet seal fluid degassing systems must conduct a performance testing to demonstrate compliance. Those performance testing requirements are contained in 40 CFR 60.5413(a). The initial performance test is required to be conducted within 180 days after initial startup. Subsequent periodic performance testing of the ECD is required once every 60 months.

Closed vent systems are required to be tested initially and annually for detectable emissions using USEPA Method 21. Also, the facility must conduct and document annual visual inspections for defects and leaks in the closed vent system that could result in air emissions.

Continuous and Periodic Monitoring
An affected centrifugal compressor must implement a continuous parameter monitoring system and implement a plan for the monitoring system design, data collection, and QA/QC elements. Affected sources required to install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the monitoring plan.

Closed vent systems are required to be tested initially and annually for detectable emissions using USEPA Method 21. Also, the facility must conduct and document annual visual inspections for defects and leaks in the closed vent system that could result in air emissions. Consult the rule for details on monitoring.

Annual Reporting
Annual reports for affected emission sources are due by January 15 each year for the previous reporting period. Consult the rules on report content. For all annual reporting, a certification by a responsible official of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping
Consult the rule's list of recordkeeping requirements to ensure compliance.

Reciprocating Compressors
The rule applies to reciprocating compressors installed after August 23, 2011. The rule only applies to the compressor and does not apply to the IC engine or motor driver.

Reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site is not an affected source. This would correspond to a "production facility." Operators commonly consider the affected compressors subject to the rule as operating at "gathering facilities." There is no USEPA given definition in the rule of a "gathering facility."

Relocated compressors that are moved to a separate facility owned and operated by the same company are not affected facilities unless modified or reconstructed as defined under 40 CFR 60.14 and 60.15.

Emission Standards
Reciprocating compressors that were installed after August 23, 2011, must change rod packing before 26,000 hours of operation or prior to 36 months from the date of the most recent rod packing replacement.

The option to change the packing every 26,000 hours is only allowed if the compressor runtime is continuously monitored.

Control Methods
Replace rod packing according to the rule's required schedule.

Important Dates
The start date for tracking the runtime hours is October 15, 2012, or the startup date for the compressor – whichever is later.

Initial Notification
Initial notification to USEPA and state authority required for affected compressors constructed (ordered), modified or reconstructed on or after October 15, 2012. The Notification required for date construction or reconstruction commenced no later than 30 days after such date. Also requires notification of the actual date of initial startup within 15 days after such date.

Annual Reporting
Annual reports for affected emission sources are due by January 15 each year for the previous reporting period. Consult the rule for details on report content.

For all annual reporting, a certification by a responsible official of truth, accuracy, and completeness. This certification must state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Recordkeeping
Consult the rule's list of recordkeeping requirements to ensure compliance.

Sweetening Units at Natural Gas Processing Facilities
The rule applies to new, reconstructed, and modified sweetening units located at onshore natural gas processing plants. Sweetening units that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (expressed as sulfur) in the unsweetened natural gas are only subject to the rule's recordkeeping and reporting requirements.

Sweetening units producing acid gas that is completely reinjected into oil-bearing or gas-bearing geologic strata, or acid gas not otherwise released to the atmosphere, are not subject to emission limits or the additional recordkeeping and reporting requirements in the final rule.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not defined as natural gas processing plant in this rule.

Emission Standards
The sulfur dioxide (SO_2) emission reduction efficiency for subject units is calculated based on the sulfur feed rate and the sulfur content of the acid gas. The emission limitations are based on Tables 1 and 2 of the rule.

Performance testing
The facility must measure flowrate to the sweetening unit and determine H_2S concentration using the Tutwiler procedure in or a chromatographic procedure following ASTM E260-96.

Monitoring
Monitoring of H_2S and SO_2 emissions required on a periodic and continuous basis (depending on the parameter) during operation of an affected gas sweetening unit. Consult the rule for details.

Recordkeeping
For affected gas sweetening units that are not exempt, consult the rule's list of recordkeeping requirements to ensure compliance.

For exempt gas sweetening units maintain records that demonstrate the facility is exempt from the control requirements. Keep on file record, for the life of the facility, an analysis demonstrating the facility's design capacity is less that 2 LT/D of H_2S in the acid gas (expressed as sulfur).