CALIFORNIA
AIR RESOURCES BOARD

Verifier Accreditation Training for Mandatory GHG Reporting

Oil and Gas Systems Specialty - Course 3.1

Upstream Extraction and Processing, Petroleum and Natural Gas (PNG) Systems

Course 3: Oil and Gas Systems Specialty

- 3.1 Upstream Extraction and Processing - Petroleum and Natural Gas (PNG) Systems
  - Verification of Onshore production of crude oil and natural gas, Natural gas processing, Natural gas transmission compression, Natural gas storage, and Natural gas distribution facilities (§95150 - 95158)
- 3.2: Petroleum Refineries (§95113)
- 3.3: Hydrogen Production Unit/Facility (§95114)

Disclaimer

This accreditation training is intended to provide administrative detail and recommended practices for compliance with the verification provisions of the California Air Resources Board's (ARB) Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions (Regulation) (Title 17, California Code of Regulations, §95100-95158).

Unlike the Regulation itself, this training and associated materials do not have the force of law. The training and associated materials are not intended to and cannot establish new mandatory requirements beyond those that are already in the regulation, and they do not supplant, replace or amend any of the legal requirements of the regulation. Conversely, any omission or truncation of regulatory requirements does not relieve verification bodies, lead verifiers, verifiers of emissions data reports, or reporting entities of their legal obligation to fully comply with all requirements of the regulation.

Note: ARB verification accreditation exams are not limited to this verification accreditation training or associated materials. The exams may test on anything contained in the regulation, this accreditation training, and associated materials.

Course 3.1 Upstream Extraction and Processing - PNG Systems

- Overview
  - MRR Sections
  - Reporting Thresholds
  - Types of PNG Facilities
  - PNG Facility Boundary and Emissions Sources
- Getting Started with the Verification
- Equipment Types
- Missing Emissions Data
- Additional Data and Activity Data
- Covered Product Data
- Nonconformances and Verification Tips

PNG MRR Sections

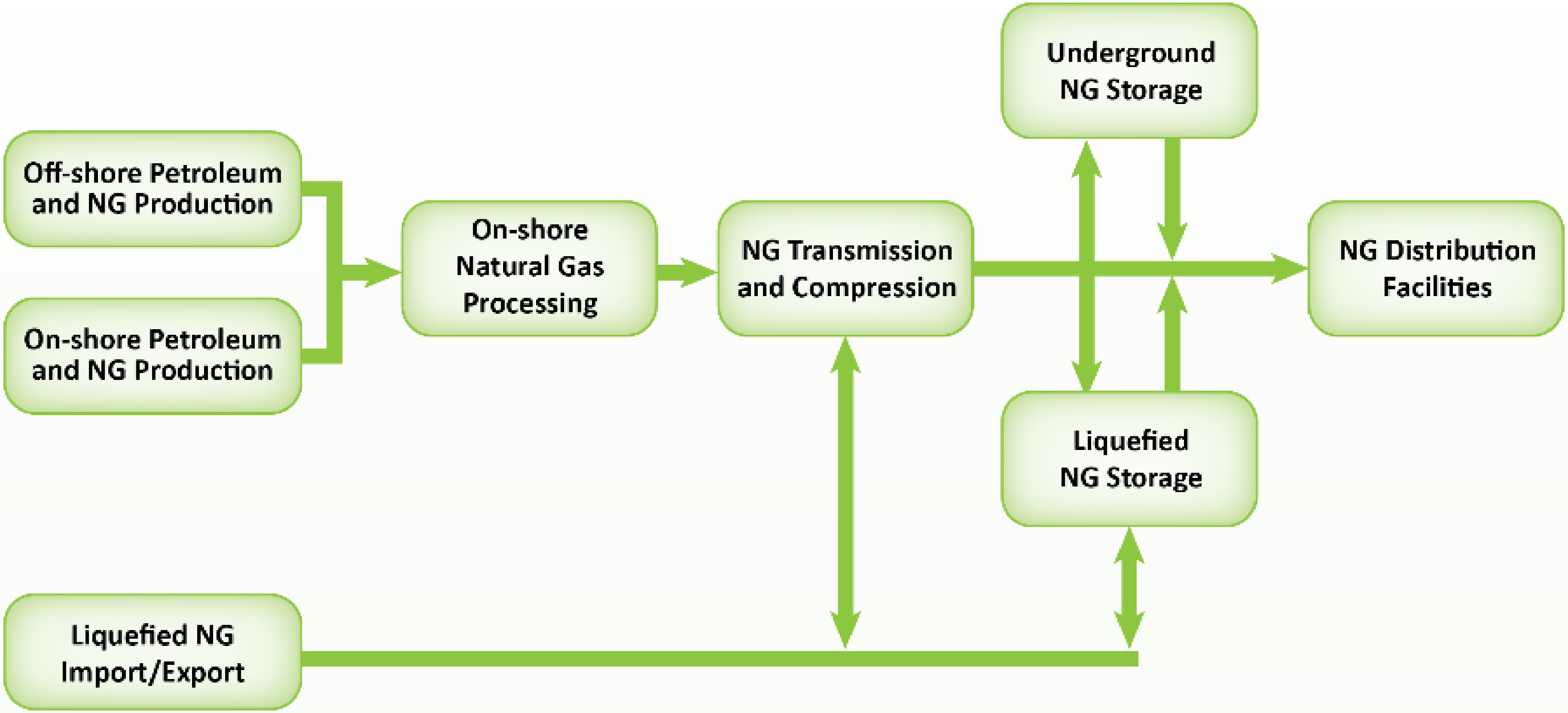
- 40 CFR Part 98 Subpart W no longer incorporated by reference
  - All PNG reporting requirements are specified in Subarticle 5 of MRR

- §95150 Definition of source category, defines <u>8 industry segments</u>
- §95151 Reporting threshold
- §95152 GHGs to report (describes the sources to include)
- §95153 <u>Emission calculation methods</u> for each source type
- §95154 Monitoring and QA/QC requirements
- §95155 Missing data procedures
- §95156 Additional reporting requirements (covered product data, thermal/electricity generation)
- §95157 Activity data reporting (equipment counts, unit throughputs)
- §95158 Document retention

Types of PNG Facilities that Must Report

- Offshore PNG production facilities
- <u>Onshore</u> PNG production facilities
- Onshore natural gas processing plants (including NGL fractionation)
- Onshore natural gas transmission compression facilities
- Underground natural gas storage facilities
- Liquefied natural gas storage facilities
- Liquefied natural gas import and export facilities
- Natural gas distribution facilities

Interrelationships of the PNG Industry Segments



Definition of Facility (Boundary) (1 of 2)

- Special definitions of facility and owner/operator in §95102(a)
  - "Facility," with respect to onshore petroleum and natural gas production (plus definition of "Basin")
  - "Onshore petroleum and natural gas production owner or operator"
  - "Facility," with respect to natural gas distribution
  - Also see: "Onshore natural gas processing" (§95150(a)(3))

Definition of Facility (Boundary) (2 of 2)

- Multiple onshore production sites in a hydrocarbon basin operated by the same entity are considered one facility
  - This is an expansion of standard definition of facility “contiguous or adjacent properties”
  - Basin-wide data must be disaggregated by sub-facility (§95102(a))
- For natural gas distribution, all pipelines and stations operated by a local distribution company

PNG Emissions Sources Reported

- Section 95152 identifies emissions sources required to be reported for each facility type
  - Stationary combustion equipment
  - Portable combustion equipment (onshore production only)
  - Pneumatic pumps and devices
  - Acid gas removal and dehydrator vents
  - Well venting
  - Pipeline dig-ins
  - Blowdowns
  - Dump valves
  - Flaring
  - Compressor venting and start-up (spin-up)
  - Fugitive leaks
  - Transmission condensate tanks
- Emissions without a compliance obligation (non-covered emissions) are listed in C&T §95852.2(b)(2-4) and (6-9)

Exempt Emissions

Onshore PNG Production	Natural gas intermittent (<6 scf/hr) pneumatic device venting Reciprocating compressor venting (<250hp) Centrifugal compressor venting (<250hp) Equipment leaks from valves, connectors, open ended lines, PRVs, and meters using population counts Equipment leaks from valves, connectors, open ended lines, PRVs, and meters using leak detection Crude Oil, Condensate, and Produced Water Dissolved CO_2 and CH_4
Onshore NG Processing	Equipment leaks from valves, connectors, open ended lines, PRVs, and meters using leak detection
Onshore NG Trans/Comp	Transmission storage tanks venting Natural gas intermittent (<6 scf/hr) pneumatic device venting [Note: All emissions from pneumatics are exempt if operated by LDC per C&T section 95852.2(b)(3)] Equipment leaks from valves, connectors, open ended lines, PRVs, and meters using leak detection
Underground NG Storage	Natural gas intermittent (<6 scf/hr) pneumatic device venting Equipment leaks from valves, connectors, open ended lines, PRVs, and meters using leak detection Equipment leaks from valves, connectors, open ended lines, and PRVs using population counts
Natural Gas Distribution	Equipment leaks from connectors, block valves, control valves, PRVs, orifice meters, regulators, and open-ended lines at above grade transmission-distribution transfer stations; Equipment leaks at below grade transmission-distribution transfer stations; Equipment at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations; Equipment leaks at below grade metering-regulating stations; Distribution main equipment leaks; Distribution services equipment leaks; Equipment and pipeline blowdowns; Emissions from customer meters; Emissions from pipeline dig-ins

§95151 Reporting Thresholds

- PNG facilities with stationary combustion and process emissions exceeding 10,000 MT CO_2e
- PNG facilities with stationary combustion, process and fugitive/vented/flared emissions exceeding 25,000 MT CO_2e
- Covers large and small crude oil and natural gas extraction and production companies, and a few natural gas transmission and distribution (T&D) companies

- Overview
- Getting Started with the Verification
- Equipment Types
- Missing Emissions Data
- Additional Data and Activity Data
- Covered Product Data
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Getting Started with the Verification (1 of 2)

- Reporting Boundaries
  - Hydrocarbon basin is the geographic boundary
  - Include parent company and subsidiaries
  - Inclusion of leased and rented equipment
- Equipment Lists
  - Field equipment schematics
  - Field equipment maintenance lists
  - Local permits for air districts

Getting Started with the Verification (2 of 2)

- Prior Reporting
  - Prior year CARB and EPA summary GHG reports
  - California DOGGR (CalGEM) data on wells and production
- Focus on Major Sources
  - Small number of sources likely dominate inventory
  - Missing sources can add significant risk of error leading to material misstatement

Standard Types of Evidence to Request

- A clear description of the facility boundaries
- Facility schematic and list of all facility equipment (district permit)
- Explanation of any significant changes in emissions or production, compared to the previous year's report
- Calibration SOPs for monitoring equipment
- GHG Monitoring Plan, which should contain
  - Missing data procedures and records used by the reporter
  - Documentation and explanations for all emission sources at the facility
  - Description of characteristics used to determine sub-facility boundaries (township, range, etc.)
- Process data and monitoring records for each facility source covered by rule
- Calculations used to pre-process inputs to Cal e-GGRT

Stationary Combustion Emissions (1 of 2)

- Stationary (and portable) combustion emissions are reported under Subpart C in the Cal e-GGRT reporting tool
  - Stationary fuel combustion for NG transmission compression, gas processing and underground storage facilities are reported according to §95115/Subpart C
  - Stationary fuel combustion for onshore production is reported according to §95115 for standard fuels, and according to §95153(y) for field gas
- All combustion emissions for Subarticle 5 facilities (§95153) must be disaggregated by sub-facility

Stationary Combustion Emissions (2 of 2)

For onshore production facilities:

- For standard fuels listed in Table C-1, use §95115 to calculate emissions
- For non-pipeline quality natural gas or field gas, use §95153(y)(2)
  - Eq. 35 for CO_2, Eq. 36 for CH_4, and Eq. 37 for N_2O
- Some exemptions for small equipment, §95153(y)(3-4)
  - external fuel combustion sources <5 MMBtu/hr
  - internal fuel combustion sources <1 MMBtu/hr
- For flares, incinerators, oxidizers and vapor combustion units, use §95153(l)
- Operators must also report sorbent emissions

Frequently Used Equations

- To convert natural gas volumes to standard conditions, use Eq. 29 §95153(r)(1)
- To convert GHG gas volumes to standard conditions, use Eq. 30 §95153(r)(2)
- To convert natural gas volumes at STP (standard conditions) to GHG gas volumes at STP, use Eq. 31 §95153(s)
  - Mole fraction (M_i) should be the annual average mole fraction for each facility, measured at location specified in §95153(s)(2)
  - Mole fraction (M_i) must be based on data from continuous monitor if installed, otherwise based on sampling methods specified in §95153(s)(2) and §95154(b)
- To convert GHG gas volumes to GHG gas mass emissions, use Eq. 32 §95153(t)

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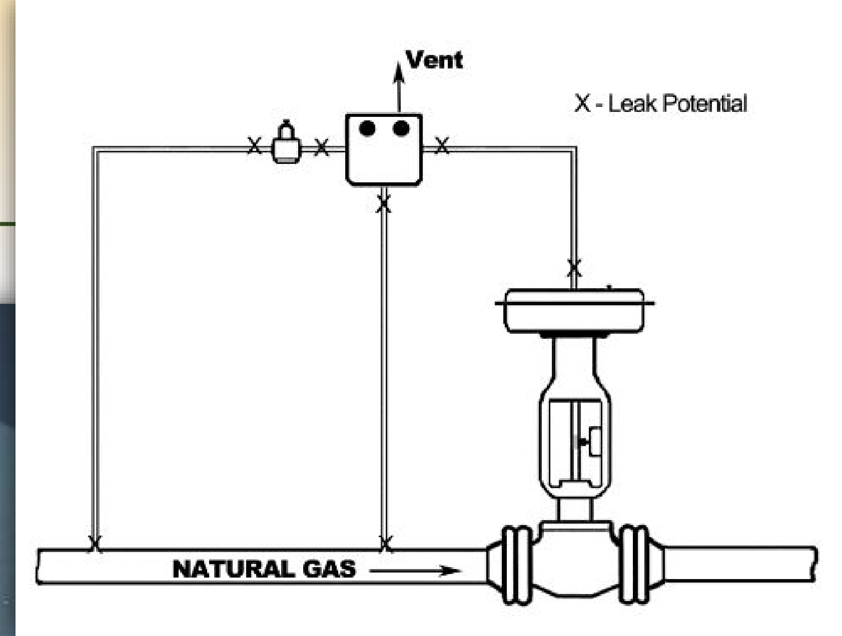
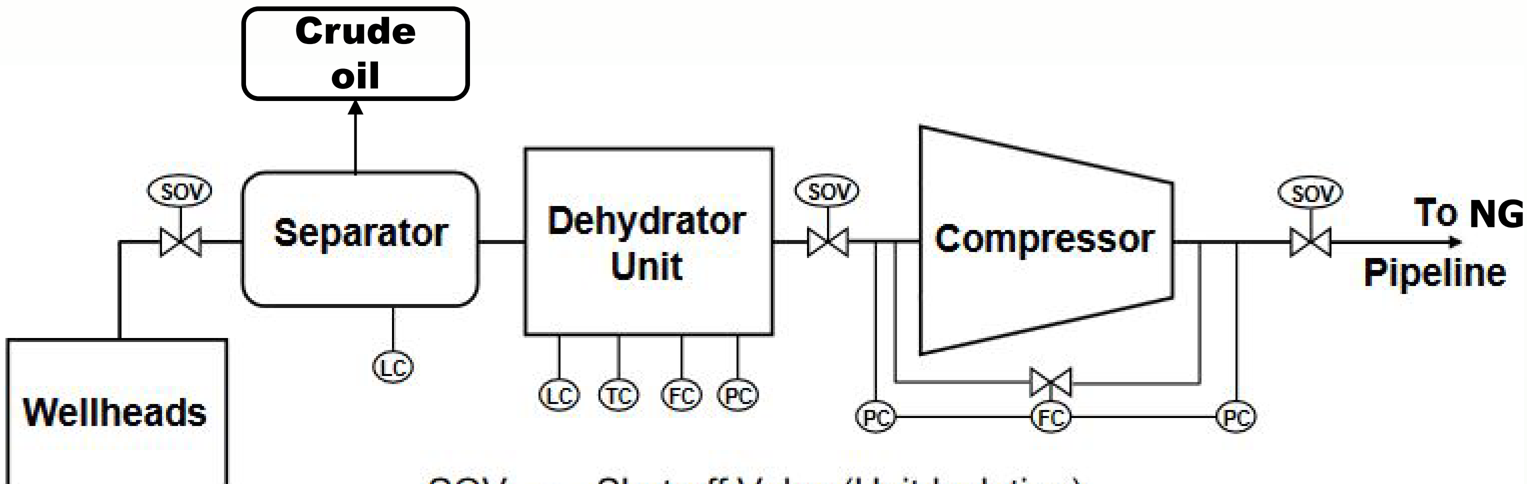
- Equipment Types
  - **Pneumatic Device and Pump Venting**
  - Acid Gas Removal (AGR) Units
  - Dehydrator Vents
  - Gas Well Venting from Liquids Unloading
  - Gas Well Venting during Completions and Workovers
  - Equipment and Pipeline Blowdowns
  - Separator Dump Valves and Condensate Tanks
  - Well Testing and Associated Gas Venting
  - Flare Stacks and Other Destruction Devices
  - Compressor Venting
  - Fugitive Leaks
  - EOR Injection Pump Blowdown Events
  - Produced Liquids and Vapor Recovery Systems

Pneumatic Valve



Location of Pneumatic Valves

- Pneumatic devices are used to actuate process controls on equipment



SOV	=	Shut-off Valve (Unit Isolation)
LC	=	Level Control (Separator, Contactor, Glycol Regenerator)
TC	=	Temperature Control (Regenerator Fuel Gas)
FC	=	Flow Control (Glycol Circulation, Compressor Bypass)
PC	=	Pressure Control (Flash Tank Pressure, Compressor Suction/Discharge)

Pneumatic Pump

Verifying CO_2 and CH_4 Emissions from NG Pneumatic Device and Pump Venting (1 of 2)

- Emissions estimated using §95153(a) and (b) Eq. 1 and 2, then Eq. 31 and 32
  - Intermittent vs continuous bleed
  - Low bleed ($\leq$6 scf/hr) vs high bleed
- Evidence to request
  - Equipment counts by type (high bleed, low bleed, continuous, intermittent bleed, pumps)
  - Equipment specification for bleed rate from manufacturer
  - Gas consumption meter records for all metered pumps and devices
  - GHG concentration in produced gas

Verifying CO_2 and CH_4 Emissions from NG Pneumatic Device and Pump Venting (2 of 2)

- How to evaluate evidence
  - Confirm all sites are represented in equipment counts
  - Verify that GHG concentrations are based on best available data for GHG mole fraction in the natural gas
  - Check volumes converted to standard conditions for emissions calculation
  - Confirm that all high bleed devices and pumps are metered (required since 2015)
  - New measurement requirement for continuous bleed pneumatics (2019+ data)

Pneumatic Device Matrix

<table>
<tr><th rowspan="2">Applicable Industry Segment</th><th rowspan="2">Data Year</th><th colspan="4">Emissions Covered?</th></tr>
<tr><th>Continuous Low Bleed</th><th>Intermittent (<6 scf/hr)</th><th>Intermittent (≥6 scf/hr)</th><th>Continuous High Bleed</th></tr>
<tr><td rowspan="6">Onshore petroleum and natural gas production, Underground natural gas storage</td><td>2014</td><td rowspan="5">No</td><td rowspan="5">No</td><td>No</td><td>No</td></tr>
<tr><td>2015</td><td rowspan="5">Yes</td><td rowspan="5">Yes</td></tr>
<tr><td>2016</td></tr>
<tr><td>2017</td></tr>
<tr><td>2018</td></tr>
<tr><td>2019+</td><td>Yes</td><td>No</td></tr>
<tr><td>Onshore natural gas transmission compression facility operated by LDC</td><td>2014+</td><td colspan="4">No</td></tr>
</table>

Case Study #1 - Non-metered Pneumatic Device Vent Emissions (1 of 2)

- An onshore natural gas transmission compression facility has 5 non-metered continuous low bleed pneumatic device vents
- There are no records establishing the number of hours the vents were operational for the year
- The mole fraction of methane in the gas is 0.95
- Calculate the annual methane emissions in metric tons CO_2e from these devices

- Also, what are the requirements for determining the mole fraction?

Case Study #1 - Non-metered Pneumatic Device Vent Emissions (1 of 2) - Solution

<u>Step 1</u>: Use §95153(b) Eq. 2 for non-metered low continuous bleed pneumatic device vents

Use emissions factor in App. A Table 3 NG Transmission Compression Low Bleed value of 1.37 scf/hr/component

5 devices x 1.37 scf/hr/device x 8760 hr = 60,006 scf NG

<u>Step 2</u>: Use Eq. 31 to convert scf NG to scf methane

60,006 scf NG x 0.95 mole fraction = 57,005.7 scf methane

<u>Step 3</u>: Use Eq. 32 to convert SCF methane to MT methane

57,005.7 scf methane x 0.0192 kg/scf x .001

= 1.0945 MT methane

Case Study #1 - Non-metered Pneumatic Device Vent Emissions (2 of 2) - Solution

- **Step 4**: Use GWP to convert to MT CO2e
  - 1.0945 x 21 = 22.98 MT CO2e (see Table A-1 for GWPs)
  - For 2021+ data: [1.0945 x 25 = 27.36 MT CO2e]
- Mole fraction requirements are specified in Eq. 31
  - Use §95153(s)(2)(C) for onshore natural gas transmission compression systems
    - If a continuous gas composition analyzer is installed, use for average annual value
    - If no analyzer, then annual samples per §95154(b)

Updated from 2020 training. See errata.

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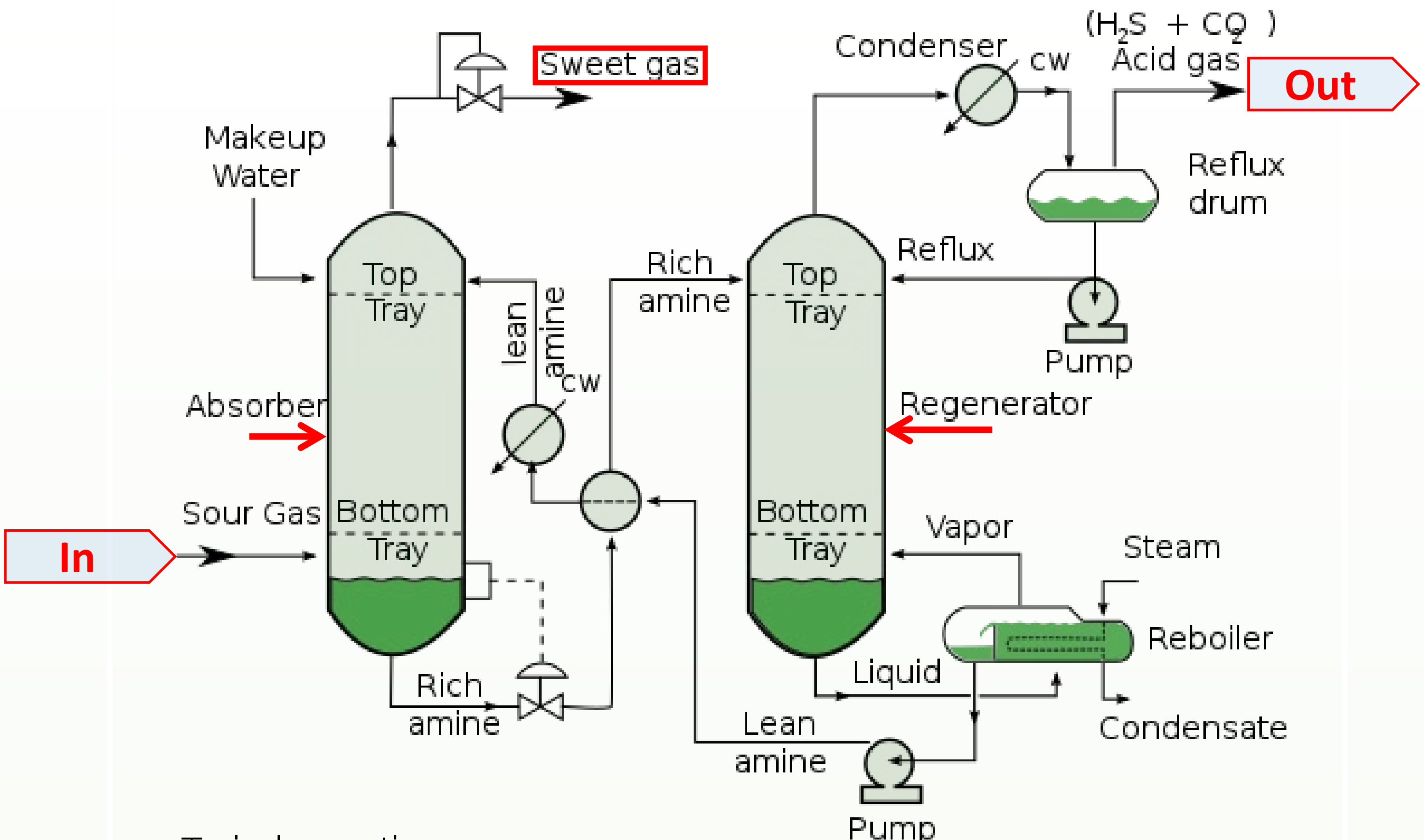
  - **Acid Gas Removal (AGR) Units**
  - **Dehydrator Vents**
  - Gas Well Venting from Liquids Unloading
  - Gas Well Venting during Completions and Workovers
  - Equipment and Pipeline Blowdowns
  - Separator Dump Valves and
  - Condensate Tanks
  - Well Testing and Associated Gas
  - Venting
  - Flare Stacks and Other Destruction
  - Devices
  - Compressor Venting
  - Fugitive Leaks
  - EOR Injection Pump Blowdown Events
  - Produced Liquids and Vapor Recovery
  - Systems

Acid Gas Removal Unit



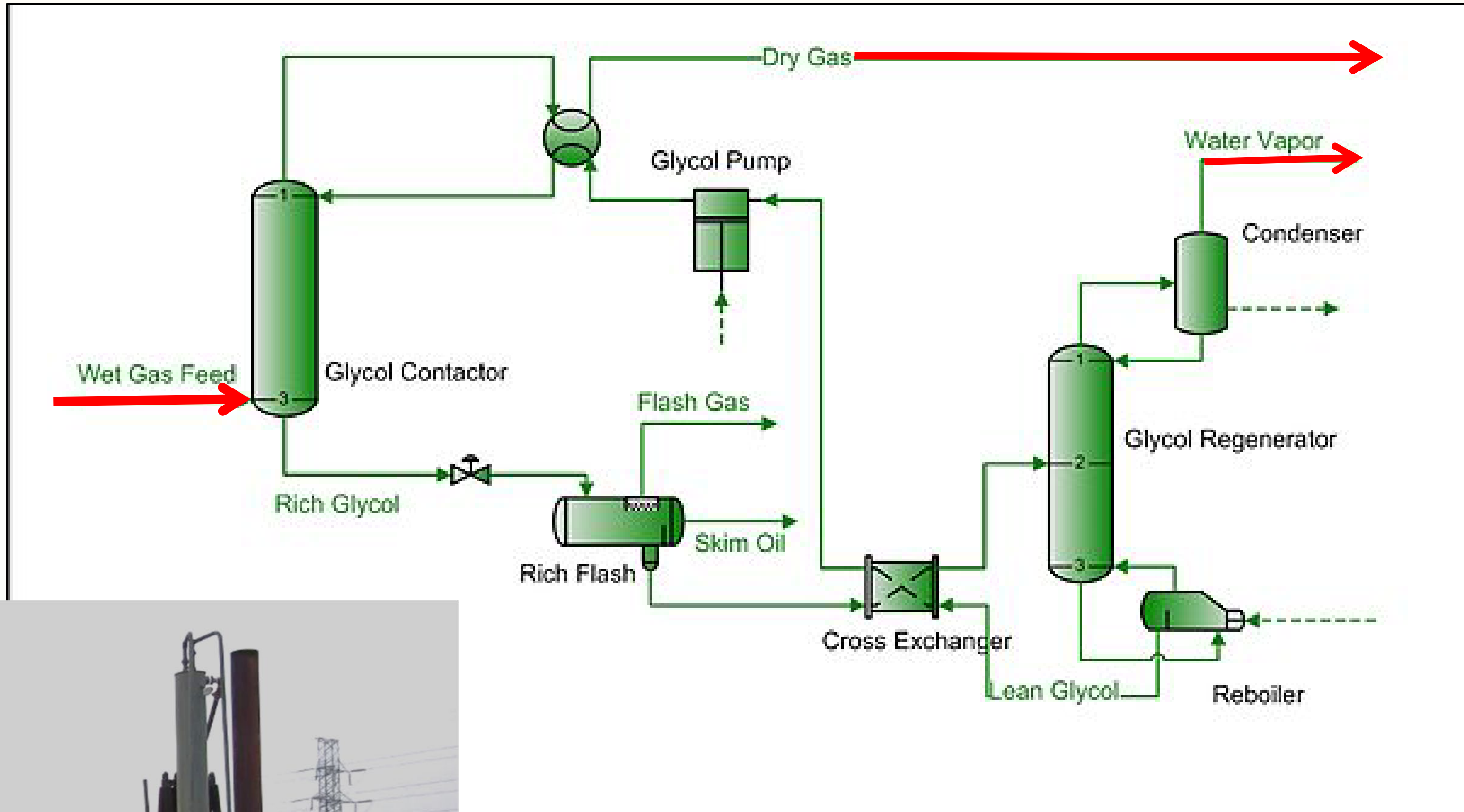
Typical operating range

absorder : 35 to 50°c and 5 to 205 atm of absolute pressure
Regenerator : 115 to 126°c and 1.4 to 1.7 atm of absolute pressure at tower bottom

Verifying CO_2 Emissions from Acid Gas Removal (AGR) Units

- **Methodology 1** CEMS §95153(c)(1) - Follow the verification procedures for Tier 4
- **Methodology 2** Vent Flow Meter §95153(c)(2) - Emissions estimated using Eq. 3 (request records of vented gas volume measurements and continuous or quarterly CO_2 sampling results)
- **Methodology 3** No CEMS or Flow Meter §95153(c)(3) - Emissions estimated using Eq. 4A or 4B (request records of process gas flow rate measurements and continuous or quarterly CO_2 sampling results)

Glycol Dehydrator



CH_4 and CO_2 Emissions from Absorber-Type Dehydrator Vents

- Software programs used
  - Aspen HYSYS
  - GRI-GLYCalc
- Typical model input parameters for accurate simulation include
  - Natural gas feed flow rate and water content
  - Outlet natural gas water content
  - Absorbent circulation pump type
  - Absorbent circulation rate
  - Absorbent type
  - Use of stripping natural gas
  - Use of flash tank separator and use of recovered gas
  - Hours operated
  - Wet natural gas temperature and pressure
  - Wet natural gas composition

Verifying CH_4 and CO_2 Emissions from Absorber-Type Dehydrator Vents

- Evidence to request
  - Software program used, input data and methods for collection of the data
  - Model outputs for CO_2 and CH_4
- How to evaluate evidence
  - Verify the simulation model is designed for natural gas dehydrators
  - Verify model inputs are based on reasonable engineering estimates and process knowledge
  - Verify eq. 29, 30, 31, and 32 are used as appropriate
  - If vapor recovery used, verify emissions were adjusted
  - If vapors sent to flare or regenerator combustion gas vent, verify emissions were calculated with flare equations (including N_2O)

Verifying CH_4 and CO_2 Emissions from Desiccant Dehydrator Vents

- Emissions estimated using §95153(d)(4) Eq. 5, and then Eq. 31 and 32
- Evidence to request
  - Records of desiccant refilling
  - Records of equipment dimensions
  - Dehydrator pressures and packed vessel void volumes
  - Inlet gas CO_2 and CH_4 composition analysis

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  - **<u>Gas</u> Well Venting from Liquids Unloading**
  - **<u>Gas</u> Well Venting during Completions and Workovers**
  - **Equipment and Pipeline Blowdowns**
  - Separator Dump Valves and Condensate Tanks
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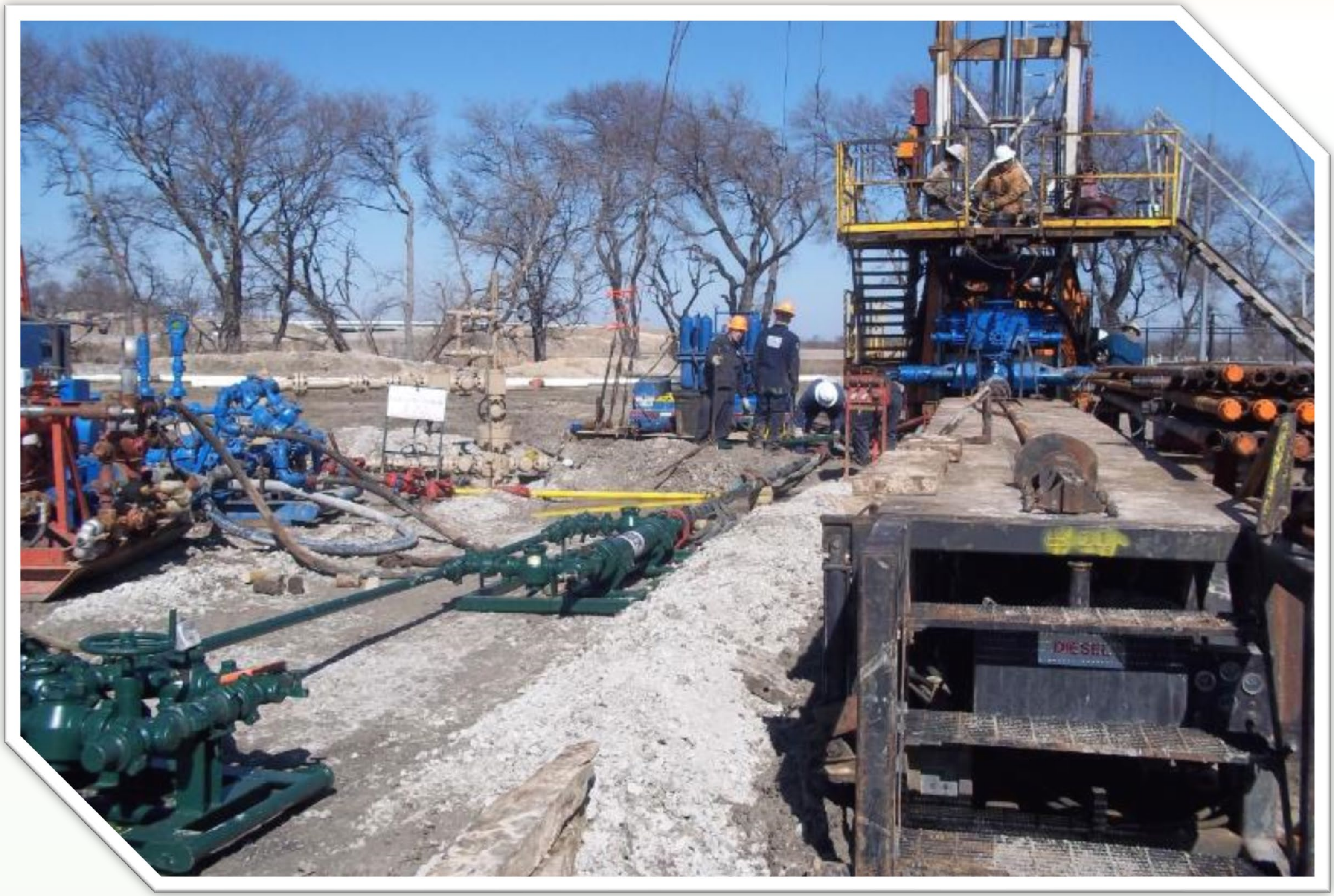
Well Heads

Verifying Gas Well Venting CH_4 and CO_2 Emissions for Liquids Unloading from Wells

- Emissions estimated using §95153(e) Eq. 6 or 7; then use Eq. 31 and 32 to convert natural gas volumes to GHG mass
- Eq. 6 is used for gas wells that do not use plunger lift assist
- Eq. 7 is used for gas wells that use plunger lift to clear liquids
- Evidence to request
  - Records of diameter, pressure, depth, flow rate, events/yr, duration, etc. for each well
  - Gas CO_2 and CH_4 composition analysis for each well
  - Pressure and temperature data (for STP conversion)

Workover Rig



Verifying CH_4 and CO_2 Emissions from Gas Well Venting during Completions and Workovers (1 of 3)

Two Methods to Calculate Emissions

- Method 1: Emissions estimated using the direct flow measurement method §95153(f)(1) Eq. 8, then use Eq. 29, 31 and 32
  - Flow meter
- Method 2: Emissions estimated using the pressure measurement method §95153(f)(2) Eq. (9, 10, 11, 12), and then use Eq. 31 and 32
  - Choke point to measure differential pressure - complicated!

Verifying CH_4 and CO_2 Emissions from Gas Well Venting during Completions and Workovers (2 of 3)

Evidence to request when the direct flow measurement method is used (method 1)

- Volume of gas vented during each event for each well
- Volume of CO_2 or N_2 injected during each event
- Volume of gas recovered into sales pipeline at each event
- Gas CO_2 and CH_4 composition analysis for each well

Verifying CH_4 and CO_2 Emissions from Gas Well Venting during Completions and Workovers (3 of 3)

Evidence to request when the pressure measurement method is used (method 2)

- Cross section area of choke orifice for each well
- Upstream temperatures during each event
- Duration of sonic flow for each event
- Upstream and downstream pressures during subsonic flow
- Duration of subsonic flow for each event
- Volume of CO_2 or N_2 injected during each event
- Volume of gas recovered into sales pipeline at each event
- Gas CO_2 and CH_4 composition analysis for each well

CO_2 and CH_4 Emissions from Blowdowns (1 of 3)

- Blowdowns apply to the depressurizing of
  - Pipelines
  - Compressor cases or cylinders
  - Manifolds and vessels
  - Suction and discharge bottles

NG volume in piping between isolation valves that is released to the atmosphere during a blowdown event

CO_2 and CH_4 Emissions from Blowdowns (2 of 3)

- Emissions estimated using either §95153(g) Eq. 13 or 14, and then use Eq. 31 and 32
- Use §95153(g) Eq. 14 for partial blowdowns
- Blowdowns from equipment and pipelines with <50 cf between isolation valves do not need to be reported
- If purged with non-GHG gas after blowdown, then Eq. 13 and 14 are set up to assume all GHGs are emitted
  - Otherwise, GHGs at atmospheric pressure are assumed to remain in system and not emitted

CO_2 and CH_4 Emissions from Blowdowns (3 of 3)

Report under other sections for

- Desiccant dehydrator blowdown venting before reloading §95153(d)
- Depressurizing to a flare §95153(l)
- Pressure relief valves §95153(o) or §95153(p)
- EOR injection pump blowdowns using critical CO_2 §95153(u)
- Pipeline dig-ins (punctures during excavation) §95153(w)
  - No reporting of emissions if NG ignites

Verifying CO_2 and CH_4 Emissions from Blowdowns

- How are blowdowns defined - what causes need to blowdown?
- Evidence to request
  - Records of all blowdown events, including number of events, temperatures and pressures of each vessel
  - Equipment specifications and calculations for vented volumes
  - Gas CO_2 and CH_4 composition analysis
- How to evaluate evidence
  - Verify that records cover the entire year
  - Verify that calculation of equipment volumes are based on standard volume equations or manufacturer specifications

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Separator Dump Valve

Transmission Condensate Separator

Verifying CO_2 and CH_4 Emissions from Separator Dump Valves and Transmission Condensate Storage Tanks

- Review annual leak detection monitoring data
- Can monitor condensate storage tank vent, or monitor for leaking separator dump valve (feeding condensate storage tank)
- Use leak detection methods described in §95154(a)-(b)
- Verify appropriate monitoring methods and conversion factors
- If leak detected (5 min. of venting or valve leak), then must report emissions

Verifying CH_4 and CO_2 Emissions from Well Testing Venting

- Emissions estimated using §95153(j), Eq. 15 (oil wells) or 16 (gas wells) and then use Eq. 29, 31 and 32
  - Volume of vented gas from Eq. 15-16 must first be converted to STANDARD CONDITIONS before using the volume as an input to Eq. 29, 31, 32
- Evidence to request
  - Records used for the determination of GOR
  - Well production records and gas composition
  - Well testing logs
- How to evaluate evidence
  - If GOR was not determined from production records, verify that it was determined using one of these methods
    - Standard method from a consensus-based standards organization or MRR flash liberation test
    - Standard practice pursuant to §95154(b)

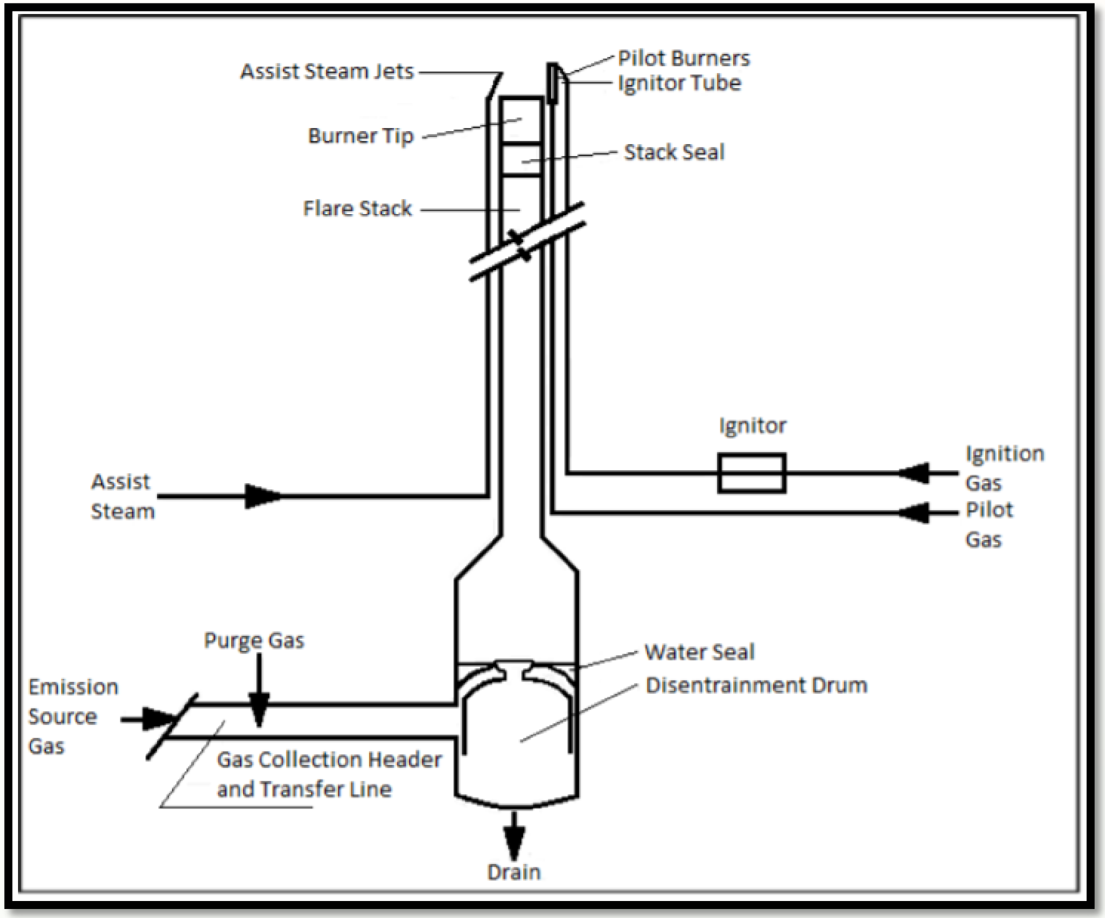
Verifying CH_4, CO_2, and N_2O Emissions from Associated Gas Venting

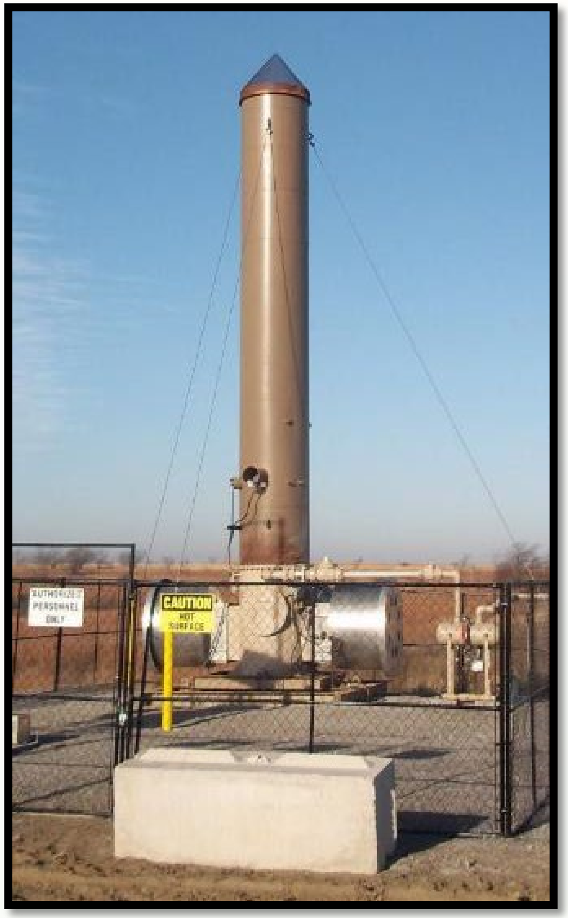
- Emissions estimated using §95153(k) Eq. 17

$$E_{a,n} = \sum_{p=1}^{x} Total\ GOR_{p,q} * V_{p,q}$$

- Then use Eq. 31 and 32 to convert to CO_2e
- Evidence to request, and how to evaluate evidence:
  - see previous slide

Flares/Incinerators





Verifying CH_4, CO_2, and N_2O Emissions from Flares

- Emissions calculated using §95153(l) Eq. 18 for CH4 and Eq. 19 for CO_2, then use Eq. 30 and 32
- For N_2O, use Eq. 29 to obtain flared gas volume, then Eq. 37 to obtain MT N_2O
- Evidence to request
  - Flare flow measurements or calculations
  - Flare gas composition measurements or calculations
  - Flare combustion efficiency from manufacturer
- How to evaluate evidence
  - Verify that continuous flow measurements are used when available; if not, verify that required methods used for engineering estimates of flow are accurate
  - Verify that continuous gas composition measurements are used when available; if not, verify that required gas compositions are used

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (1 of 2)

- An onshore petroleum and natural gas production facility has 10 oil wells and 5 natural gas wells within the same hydrocarbon basin.
- The oil well production rate is 12 bbl/day with a GOR of 322 scf/bbl. The gas well production rate is 70 Mcf/day.
- Each oil well was tested for a total of 8 days per year and each gas well was tested for a total of 4 days per year.
- Assume all gases are vented during all wellhead testing, and associated gases are vented during production.

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (2 of 2)

- Calculate the volume of natural gas emitted during wellhead testing.
- What information is missing to verify the emissions?
- What procedures would be used if the GOR could not be determined from available data?
- Calculate the natural gas emissions for associated gas venting.
- How would the emissions be calculated if the associated gas was sent to a flare?

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (1 of 4) - Solution

- Use §95153(**j**)(3) Eq. 15 for **<u>Oil Well Testing</u>** Emissions
- 322 scf/bbl GOR x 12 bbl/day x 8 days x 10 wells = 309,120 scf natural gas
- Calculate the volume of methane and CO_2 using §95153(s) Eq. 31 (<u>need CH_4 and CO_2 mole fraction data</u>)
- Calculate the MT methane and CO_2 using Eq. 32, then calculate the CO_2e

Must have a GOR value from each well, or from a cluster of wells with similar GOR values. If GOR cannot be determined from available data, operator must have GOR tested (per Flash Liberation Test in App. B, or other published standard).

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (2 of 4) - Solution

- Use §95153(**j**)(3) Eq. 16 for **Gas Well Testing** Emissions
- 70 Mcf/day x 4 days x 5 wells = 1,400 Mcf NG
- Adjust to STP using Eq. 29 (need gas flow temperature and pressure data)
- Calculate the volume (in scf) of methane and CO_2 using Eq. 31 (need CH_4 and CO_2 mole fraction data)
- Calculate MT methane and CO_2 using Eq. 32, then calculate CO_2e

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (3 of 4) - Solution

- Associated Gas Emissions if **Vented**
- Use §95153(**k**) Eq. 17 for Associated Gas Venting and Flaring
- 322 scf/bbl GOR x 12 bbl/day x **365** days x 10 wells
  = 14,104 Mscf natural gas
- Calculate the scf CH_4 and CO_2 using Eq. 31 (need CH_4 and CO_2 mole fraction data)
- Calculate MT CH_4 and CO_2 using Eq. 32, then calculate CO_2e

Case Study #2 - Wellhead Test Venting and Associated Gas Flaring (4 of 4) - Solution

Associated gas emissions if **Flared**

- Use Eq. 18 and 19, and use Eq. 37 (for N_2O) to calculate flare emissions
  - Additional data needed includes the operating records for the combustion device, the destruction efficiency (or can use 98% default), the composition of the associated gas sent to the incinerator (mole fraction of CO_2, methane, ethane, propane, butane and pentane+), and the HHV, temperature and pressure of the associated gas

- Overview
- Getting Started with the Verification
- Equipment Types
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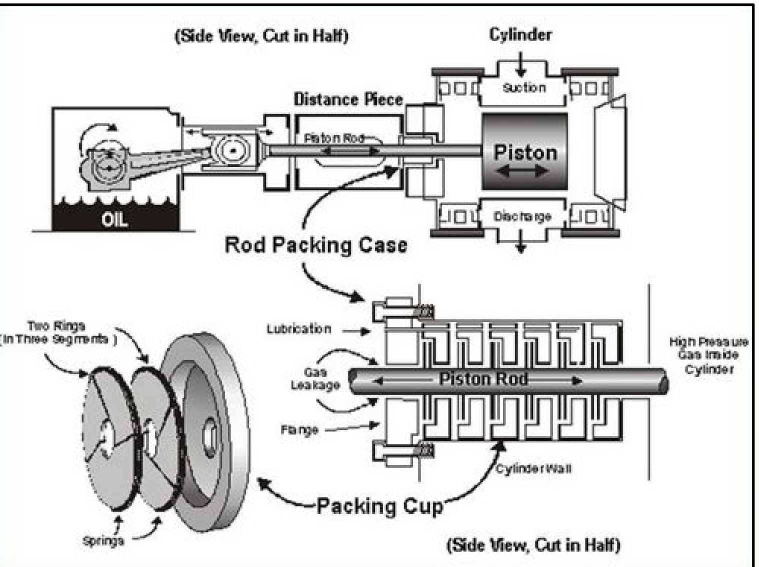
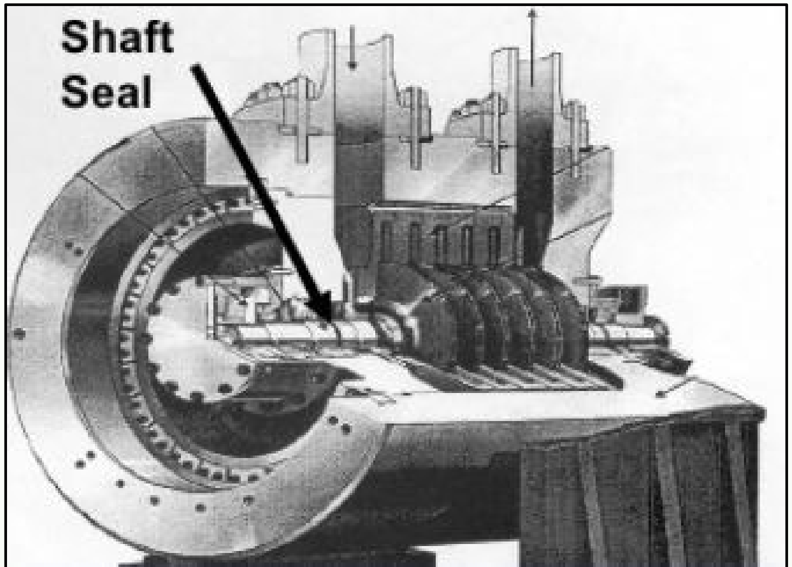
  - Acid Gas Removal (AGR) Units
  - Dehydrator Vents
  - Gas Well Venting from Liquids Unloading
  - Gas Well Venting during Completions and Workovers
  - Equipment and Pipeline Blowdowns
  - Separator Dump Valves and Condensate Tanks
  - Well Testing and Associated Gas Venting
  - Flare Stacks and Other Destruction Devices
  - **Compressor Venting**
  - **Fugitive Leaks**
  - **EOR Injection Pump Blowdown Events**
  - Produced Liquids and Vapor Recovery Systems

Compressor Venting

- Reciprocating/Centrifugal compressors are used for increasing the pressure of produced gas for use in downstream units, or to sales gas line
- Gas is vented to atmosphere during normal operations, and even when unit is not operating (e.g., vent leaks through isolation valves)





CH_4 and CO_2 Emissions from Compressor Venting

- Emissions estimated using §95153(m) and (n)
  - $\geq$250 hp uses test data with Eq. 21 or 23 (covered emissions)
  - <250 hp allows default EF with Eq. 22 or 24 (non-covered)
- For ≥ 250 hp, operator must conduct an annual measurement in each mode in which the compressor operates for more than 200 hours in the calendar year
- For centrifugal compressors §95153(m)(1)(A): estimate emissions from vented gas that was used to start operation (spin-up gas) Eq. 20

Verifying CH_4 and CO_2 Emissions from Compressor Venting (1 of 2)

Evidence to request

- For <u>centrifugal</u> compressors: test data for blowdown leakage, wet seal degassing vents, isolation valve leakage through blowdown vent
- For <u>reciprocating</u> compressors: rod packing vents, isolation valve vents and blowdown valve vents
- Compressor operating logs, horsepower, and hours of operation in each mode

Verifying CH_4 and CO_2 Emissions from Compressor Venting (2 of 2)

More evidence to request

- Monitoring procedures and data
- Analysis of NG composition
- Total counts of compressors in each segment of the industry
- Gas drive systems used for spin-up
- Flare combustion efficiency from manufacturer, if flare is used (not reported as vented)

Fugitive Leaks: Measure, or Population Counts

Fugitive Leaks for §95153(o) "Leak detection and leaker emission factors"

- Industry segments that must use leak test method:
  - Natural gas processing facilities §95152(d)(7)
  - Transmission compression facilities §95152(e)(8)
  - For natural gas distribution:
    - Above-grade T&D stations under §95152(i)(1) must be leak-tested
    - Other types of leaks can use population count method (§95153(p))
- Must first conduct leak detection procedures:
  - If no leak is detected, emissions are 0 (zero)
  - If a leak is detected, emissions are calculated using Eq. 25 (or Eq. 26 for NG distribution systems) and default emission factors Tables 1 through 7 in Appendix A

Fugitive Leaks for §95153(p) "Population count and emission factors"

- Only allowed for certain industry segments
  - Onshore production equipment leaks §95152(c)(16)
  - Underground NG storage equipment leaks §95152(f)(7)
  - LNG storage and import/export equipment leaks §95152(g)(5) and (h)(5)
  - NG distribution leaks (i)(2-6), and (i)(10)
    - <u>Except</u> above-grade T&D stations (i)(1)
- Use §95153(p) Eq. 27 or 28, and Tables 1-7 in App. A

- <u>For both §95153(o) and (p) methods</u>:
  - Exemptions apply to small tubing (< ½ inch diameter), and to gases with low GHG concentration (< 10% CO_2 + CH_4 by weight)

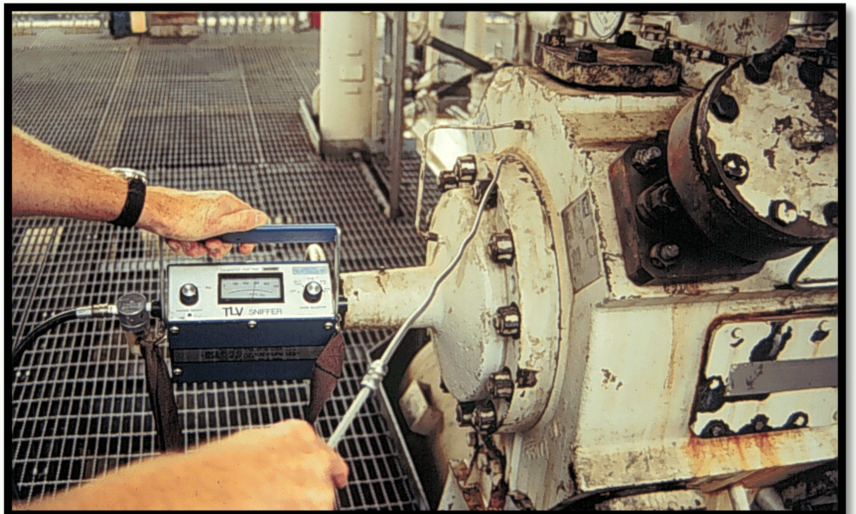
Leak Screening (§95154)

Verifying Monitoring Data from Leak Detection

- Acceptable monitoring methods
  - Optical gas imaging instrument https://www.youtube.com/watch?v=HanXGD2NJxk (only acceptable method for inaccessible sources)
  - Infrared laser beam illuminated instrument
  - For methods above, any detected emissions is a leak, unless further screened using U.S. EPA Method 21
    - Only measurement ≥ 10,000 ppm is a leak
  - Acoustic leak detection device for through-valve leakage
    - Leakage rate ≥ 3.1 scf/h is a leak
- Verify that each device was operated, maintained and calibrated according to manufacturer specifications

Verifying CH_4 and CO_2 Emissions from Fugitive Leaks (1 of 2)

- Evidence to request
  - Inventory of components by type and service
  - Annual leak test records for all components listed in Tables 1-7 of Appendix A
  - Gas analysis for each onshore NG processing facility (downstream facilities use default analysis)



Verifying CH_4 and CO_2 Emissions from Fugitive Leaks (2 of 2)

- How to evaluate evidence
  - Verify correct components were included in the leak surveys
  - Verify proper leak detection procedures and frequencies used
  - Verify gas analysis is consistent with other analysis at the facility
  - Confirm that correct emission factors were applied

- Reminder: Fugitive emissions are not “covered” and do not need to meet the +/-5% accuracy requirement

Verifying Flow Meters, Composition Analyzers and Pressure Gauges

- Meters, analyzers and gauges must meet accuracy requirements of §95103(k) and 40 CFR 98.3(i)
- Evidence to request
  - Documentation on meter type, specifications, maintenance and calibration requirements
  - Operating, maintenance and calibration logs to verify proper procedures were followed

Verifying Monitoring Data from High Volume Samplers and Calibrated Bags

- Required for some sources, to measure emissions from equipment vents (compressors, etc.)
  - For calibrated bags, verify that the operator followed the requirements in §95154(c)
  - For high volume samplers, verify that the operator followed the requirements in §95154(d)

Verifying CO_2 Emissions from EOR Injection Pump Blowdown Events

- Estimated using §95153(u) Eq. 33
- Evidence to request
  - Records of blowdown events
  - Records of injection gas density and determination methods
  - System design information used to calculate volume between isolation valves (blowdown volume)
  - Mass fraction of GHGs in injection gas
- How to evaluate evidence
  - Verify that data were entered correctly into Cal e-GGRT and that calculations are correct

Case Study #3 - Gas Compressor Operations and Metering

- A large compressor station moving natural gas from a processing plant through transmission lines has <u>four</u> natural gas fired turbine driven <u>centrifugal</u> compressors. The station does not have CEMS, and meters total fuel flow to the turbines.
- During the site visit, it was noted that the compressors use gas to <u>spin-up</u> (start up) the turbines, and this spin-up gas is vented.
- What PNG <u>sections</u> of the rule would be used to calculate emissions?
  - How would you verify turbine spin-up emissions?

Case Study #3 - Gas Compressor Operations and Metering - Solution (1 of 4)

- Categorization of the Facility
  - A gas compressor station moving natural gas from a processing plant through transmission lines falls under §95150(a)(4) Onshore Natural Gas **Transmission Compression** industry segment
- Section 95152(j) states the requirements for reporting stationary combustion sources
  - Transmission compression facilities primarily use Tier 2 calculation method referenced in section 95115
- Section 95153(m)(1)(a) states the requirements for reporting emissions from centrifugal compressor start-ups

Case Study #3 - Gas Compressor Operations and Metering - Solution (2 of 4)

Section 95152(e) lists the following emission sources:

(1) Metered natural gas pneumatic device and pump venting;

(2) Non-metered natural gas pneumatic device venting;

(3) Equipment and pipeline blowdowns;

(4) Transmission storage tanks;

(5) Flare stack or other destruction device emissions;

(6) <u>Centrifugal compressor venting</u>;

(7) Reciprocating compressor venting; and

(8) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

Case Study #3 - Gas Compressor Operations and Metering - Solution (3 of 4)

Turbine Spin-up Emissions

- The fuel used to spin-up the centrifugal turbines leads to vented CH_4 and CO_2 emissions that must be estimated.
  - Records of turbine start-up events, and engineering data on the volume of gas used to spin-up the turbines should be obtained.
- Section 95153(m) provides the calculation method for spin-up emissions.
  - The vented spin-up emissions can significantly increase the total MT CO_2e emissions compared to when all the turbine inlet fuel is combusted.

Case Study #3 - Gas Compressor Operations and Metering - Solution (4 of 4)

Other Emissions Sources

- Site schematics and equipment lists should be used to determine the number of each type of emitting equipment (e.g. pneumatic devices, transmission condensate storage tanks, pressure relief values, etc.) associated with the facility
- Emissions from each type of component should be calculated following §95153

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  - EOR Injection Pump Blowdown Events
  - **Produced Liquids and Vapor Recovery Systems**

Tank and Separator

Vent and Separator

CH_4 and CO_2 Emissions from Produced Liquids

- Includes crude oil, hydrocarbon liquid condensate, and produced water sent to tanks, ponds and holding facilities

$$E_{CO2/CH4} = (S * V)\big(1 - (VR * CE)\big) \qquad \text{Eq. 33A}$$

"S" is from either flash liberation test or vapor recovery method

V = Barrels of crude oil, condensate, or produced water sent to tanks, ponds, or holding facilities annually.

VR = Percentage of time the vapor recovery unit was operational

CE = Collection efficiency of the vapor recovery system

Produced Liquid Emissions – Flash Liberation Tests

- Measures composition and volume of gas released from produced liquids upon the change from reservoir to standard atmospheric pressure
- See Appendix B for required sampling and test procedures
  - Crude oil and condensate (gas to oil ratio - GOR)
  - Produced water (gas to water ratio - GWR)
- The operator should justify the number and location of flash liberation testing points, with particular attention to multiple separators present within a facility
- Sampling must follow new testing frequency requirement

$$\boldsymbol{GOR = {}^{150\ scf\ gas}/_{0.5\ Bbl\ oil} = 300\,\frac{scf}{Bbl}}$$

Produced Liquid Emissions – Vapor Recovery Systems (VRS)

- If emissions from produced fluids are controlled using a VRS, follow methods in Appendix B, Sections 9 and 10.2
- VRS must meet specifications listed in §95153(v)(1)(A)(2)
- Calculate emissions for vented (unrecovered) vapors and for flared (captured) vapors (per flare emission procedures, §95153(l), including N_2O)
- Evidence to request
  - VRS efficiency and annual flow to VRS and supporting records
  - Gas composition and supporting records
  - Flare system data and results

- Overview
- Getting Started with the Verification
- Equipment Types
- **Missing Emissions Data**
- **Additional Data, and Activity Data**
- Covered Product Data
- Nonconformances and Verification Tips

Procedures for Substituting Missing Emissions Data (§95155)

- Sources calculated according to §95115 - follow requirements of §95129
- For other Subarticle 5 sources:
  - Capture rate ≥ 90% - substitute the best available estimate of the parameter, using available process data
  - Capture rate ≥ 80% and < 90% - substitute highest value recorded during the year and two previous years
  - Capture rate < 80% - substitute highest value recorded in all records kept according to §95105(a)

Verifying Missing Emissions Data Substitutions

- Evidence to request for each incident
  - Documentation on the data lost and the cause for the loss
  - Missing data substitution procedures applied, and justification
  - Data records and calculations for each substitution
- How to evaluate evidence
  - Verify the appropriate data were applied
  - Verify the appropriate procedure was applied
  - Verify the accuracy of the calculations

Additional Data Reported Under §95156

For Onshore Production Facilities:

- Data also reported again by sub-facility
  - Fuel use by fuel type for combustion sources
  - Cogeneration data
    - Steam and electricity generation, MWh sold
  - Steam generator data
    - MMBtu of steam generated, MMBtu of steam sold
  - Electricity generation data
    - Net generation, MWh sold
  - CO_2e associated with these activities (rough estimate)
- Covered product data (*super important*)

Activity Data §95157

- Extensive list of Activity Data to be reported
  - Submitted as a spreadsheet attached to Cal e-GGRT report
- Establish reasonable assurance of conformance with reporting requirements
  - Evaluate risk of mis-reporting from their data system
  - Sample underlying measurements and data collection as needed
- Reporters use best available data to apportion combustion emissions to the process and unit level where required in §95157
- Activity data should be consistent with emissions data and sources
  - Compare data on process units and activity

- Overview
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- Missing Emissions Data
- Additional Data and Activity Data
- Covered Product Data
- Nonconformances and Verification Tips

Verifying Covered Product Data (1 of 8)

- Reminder: review definitions of covered product data and Tables 8-1 and 9-1 in Cap-and-Trade Regulation
- Required Product Data for petroleum and natural gas production and processing facilities
  - Barrels of crude oil produced using thermal EOR
  - Associated gas produced using thermal EOR (MMBtu)
  - Barrels of crude oil produced using methods other than thermal EOR
  - Associated gas produced using methods other than thermal EOR (MMBtu)
  - Dry gas produced (MMBtu)
  - NGLs (if the facility fractionates and sells natural gas liquids)
  - Natural gas processed (facilities that process > 25MMscf/day)

Verifying Covered Product Data (2 of 8)

<u>Crude oil</u> covered product data:

- Thermal EOR and non-thermal EOR covered product data reported separately
  - For thermal production, verify the presence of steam generation for the field
- Covered product data material misstatement for crude oil and associated gas is based on total barrels of oil equivalent (BOE)
- BOE = barrels of crude + [MMBtu associated gas and dry gas]/5.8
- Regulatory change for <u>2019+</u> data requires separate material misstatement for thermal vs non-thermal EOR

Verifying Covered Product Data (3 of 8)

- Can use sales data to report crude oil product volume. If financial transactions/LACT meters are used, the reporter should disregard starting and ending inventory amounts in tanks
  - If sales with an inventory adjustment is used, the inventory adjustment is end-of-year inventory minus beginning-of-year inventory
- Measurement systems must meet §95103(k), including inventory method
- Verify methods used are consistent with prior year; any change in methods must follow §95103(m)

Verifying Covered Product Data (4 of 8)

<u>Associated gas</u> covered product data:

- Includes all associated gas from well, whether sold, burned on-site, re-injected, vented or flared
  - Data can be from calibrated gas meters
  - Data can be from GOR from flash liberation test applied to volume of oil associated with GOR test, plus GWR applied to volume of produced water

<u>Dry gas</u> covered product data:

- Production also subject to material misstatement

Verifying Covered Product Data (5 of 8)

- Ask for an explanation of any significant year-over-year changes in production
- Facility GHG Monitoring Plan must include specific information on methods used to quantify crude oil, associated gas, and dry gas product data
  - How product data are quantified for MRR (thermal / non-thermal), and disaggregated by sub-facility (sub-facility boundaries also described in GHG plan)
  - Description and schematic diagram of process and measurement points (recommended)
- Recommend comparing against DOGGR/CalGEM data
  - How is product data disaggregated for CalGEM?
  - CalGEM data are not expected to match MRR data exactly
- Speak with the reporter's accounting staff
  - Verify completeness; all fields, leases and partner shares should be accurately calculated and reported

Verifying Covered Product Data (6 of 8)

NGL Production Data (§95156(c))

- Applies to a natural gas liquid fractionation facility, a natural gas processing facility, or an onshore production facility with a gas processing plant that processes ≤25 MMscf/day
  - Report natural gas liquids produced (bbl corrected to 60 °F)
    - Propane, Butane, Pentanes plus, etc.
  - If NGLs are produced and re-injected into crude oil at the same facility, the NGL volume is included as crude oil product data, and not as NGL product data
- For NGL fractionators with basin production
  - Requires both Transactions and O&G sector accreditation

Verifying Covered Product Data (7 of 8)

- For onshore natural gas processing facilities that process >25 MMscf/day
  - Report natural gas liquids (NGLs) produced (bbl corrected to 60 °F)
    - Propane, Butane, Isobutane, Pentanes plus, etc.
  - Associated gas, waste gas and natural gas processed (in MMBtu)
    - Can be from calibrated input gas meters
    - Can be from output (MMBtu of produced NGLs plus MMBtu of residue gas, from sales or calibrated meters)

Verifying Covered Product Data (8 of 8)

- The operator is responsible for reporting all crude oil, associated gas, dry gas, NGLs and gas processed product data for the facility
- Financial agreements affecting the ownership of product should generally be reviewed to ensure other entities' financial interests do not inadvertently result in not reporting covered data
- Ensure reported NAICS code(s) cover all product data activities
- Inaccurate covered product data must be excluded to avoid an adverse product data verification statement, however the quantity of inaccurate product data must still be estimated and reported (applies to all product data, §95103(l))

Nonconformances and Verification Tips

Examples of Operator Non-conformances Identified by Verifiers:

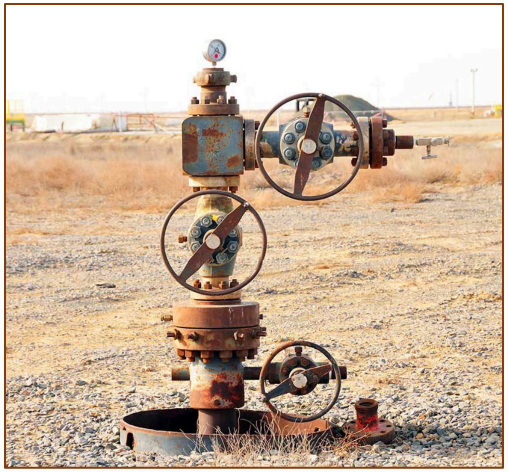
- Emissions from flare used for truck load-out not included in report
- Emissions from dew point heater not included in report
- Emissions from compressors upstream from fuel meter not reported
- Volume of produced water not reported
- Meter calibration details not included in GHG Monitoring Plan
- Volume of fuel gas quantified incorrectly
- Incorrect emission factor applied for Subarticle 5 source (e.g., pneumatic devices)
- Incomplete equipment and fuel usage data from new oil field acquisitions

Verification Tips

- In Verification Report:
  - Describe the methods used by operator/verifier to quantify product data
  - Include percent error calculation for covered product data and covered emissions data
- Briefly review activity data for accuracy and consistency with emissions data

Course 3: Oil and Gas Systems Specialty

- Complete:
  - 3.1 Upstream Extraction and Processing - Petroleum and Natural Gas (PNG) Systems



- Next:
  - **3.2 Petroleum Refineries**
  - 3.3 Hydrogen Production