DRAFT RULE LANGUAGE
For Advisory Committee Review

Chapter 173-441 WAC
Reporting Emissions of Greenhouse Gases

Appendix A-1:

Natural Gas extraction, processing, storage, transmission, and distribution

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§A-1, Section 1 Definition of the source category.

This source category consists of the following facilities:
(a) Onshore natural gas processing facilities.
(b) Onshore natural gas transmission compression facilities.
(c) Natural gas transmission and distribution systems.
(d) Underground natural gas storage facilities.
(e) Liquefied natural gas storage facilities.
(f) Liquefied natural gas import and export facilities.

§A-1, Section 2 Sources of GHGs to include in report.
(a) You must report CO₂ and CH₄ emissions in CO₂e metric tons per year from sources specified in §A-1, Section 2(a)(1) through (25) at onshore natural gas processing facilities, onshore natural gas transmission compression facilities, natural gas transmission and distribution systems, underground and above ground natural gas storage facilities, liquefied natural gas storage facilities and liquefied natural gas import and export facilities.
(1) Acid gas removal (AGR) vent stacks.
(2) Blowdown vent stacks.
(3) Centrifugal compressor dry seals.
(4) Centrifugal compressor wet seals.
(5) Compressor fugitive emissions.
(6) Compressor wet seal degassing vents.
(7) Dehydrator vent stacks.
(8) Flare stacks.
(9) Liquefied natural gas import and export facilities fugitive emissions.
(10) Liquefied natural gas storage facilities fugitive emissions.
(11) Natural gas driven pneumatic pumps.
(12) Natural gas driven pneumatic manual valve actuator devices.
(13) Natural gas driven pneumatic valve bleed devices.
(14) Non-pneumatic pumps.
(15) Offshore platform pipeline fugitive emissions.
(16) Open-ended lines (OELs).
(17) Pump seals.
(18) Platform fugitive emissions.
(19) Processing facility fugitive emissions.
(20) Reciprocating compressor rod packing.
(21) Storage station fugitive emissions.
(22) Storage tanks.
(23) Storage wellhead fugitive emissions.
(24) Transmission station fugitive emissions.
(25) Transmission and distribution pipeline inspection and maintenance activities

(b) Emissions from combustion of natural gas or other fuels associated with above operations
must be calculated per the methods in WAC 173-441-100(2)

§A-1, Section 3 Calculating GHG emissions.
(a) Estimate emissions using either an annual direct measurement, as specified in §A-1, Section 4, or an engineering estimation method specified in this section. You may use the engineering estimation method only for sources for which a method is specified in this section.
(b) You may use engineering estimation methods described in this section to calculate emissions from the following fugitive emissions sources:
(1) Acid gas removal vent stacks.
(2) Natural gas driven pneumatic pumps.
(3) Natural gas driven pneumatic manual valve actuator devices.
(4) Natural gas driven pneumatic valve bleed devices.
(5) Blowdown vent stacks.
(6) Dehydrator vent stacks.
(7) Natural gas pigging operations.
(8) Pipeline maintenance and purging operations.
(c) A combination of engineering estimation described in this section and direct measurement described in §A-1, Section 4 shall be used to calculate emissions from the following fugitive emissions sources:
(1) Flare stacks.
(2) Storage tanks.
(3) Compressor wet seal degassing vents.
(d) You must use the methods described in §A-1, Section 4 (d) or (e) to conduct annual leak detection of fugitive emissions from all sources listed in §A-1, Section 2 (a). If fugitive emissions are detected, engineering estimation methods may be used for sources listed in
paragraphs (b) and (c) of this section. If engineering estimation is used, emissions must be calculated using the appropriate method from paragraphs (d) through (9) of this section:

1. Acid gas removal vent stack. Calculate acid gas removal vent stack fugitive emissions using simulation software packages, such as ASPEN™ or AMINECalc™. Any standard simulation software may be used provided it accounts for the following parameters:
   (i) Natural gas feed temperature, pressure, and flow rate.
   (ii) Acid gas content of feed natural gas.
   (iii) Acid gas content of outlet natural gas.
   (iv) Unit operating hours, excluding downtime for maintenance or standby.
   (v) Exit temperature of natural gas.
   (vi) Solvent pressure, temperature, circulation rate and weight.

2. Natural gas driven pneumatic pump. Calculate fugitive emissions from a natural gas driven pneumatic pump as follows:
   (i) Calculate fugitive emissions using manufacturer data.
      (A) Obtain from the manufacturer specific pump model natural gas emission per unit volume of liquid pumped at discharge pressures.
      (B) Maintain a log of the amount of liquid pumped annually from individual pumps.
      (C) Calculate the natural gas fugitive emissions for each pump using Equation A-1.1 of this section.

\[
E_{s,n} = F_s \times V 
\]  
(Eq. A-1.1)

Where:

\( E_{s,n} \) = Natural gas fugitive emissions at standard conditions.
\( F_s \) = Natural gas driven pneumatic pump gas emission in “emission per volume of liquid pumped at discharge pressure” units at standard conditions, as provided by the manufacturer.
\( V \) = Volume of liquid pumped annually.

(D) Both CH₄ and CO₂ volumetric and mass fugitive emissions shall be calculated from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) If manufacturer data for \( F_s \) are not available, follow the method in §A-1, Section 4 (i)(1).

3. Natural gas driven pneumatic manual valve actuator devices. Calculate fugitive emissions from a natural gas driven pneumatic manual valve actuator device as follows:
   (i) Calculate fugitive emissions using manufacturer data.
      (A) Obtain from the manufacturer specific pneumatic device model natural gas emission per actuation.
      (B) Maintain a log of the number of times the pneumatic device was actuated throughout the reporting period.
      (C) Calculate the natural gas fugitive emissions for each manual valve actuator using Equation A-1.2 of this section.

\[
E_{s,n} = A_s \times N 
\]  
(Eq. A-1.2)
(D) Calculate both CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in §A-1, Section 4(i)(2) if manufacturer data are not available.

(4) Natural gas driven pneumatic valve bleed devices. Calculate fugitive emissions from a natural gas driven pneumatic valve bleed device as follows:

(i) Calculate fugitive emissions using manufacturer data.

(A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.

(B) Calculate the natural gas fugitive emissions for each valve bleed device using Equation A-1.3 of this section.

\[ E_{s,n} = B_s \* T \]  
(Eq. A-1.3)

Where:

\[ E_{s,n} = \text{Natural gas fugitive emissions at standard conditions.} \]
\[ B_s = \text{Natural gas driven pneumatic device bleed rate in “emission per unit time” units at standard conditions, as provided by the manufacturer.} \]
\[ T = \text{Amount of time the pneumatic device has been operational through the reporting period.} \]

(C) Calculate both CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(ii) Follow the method in §A-1, Section 4(i)(3) if manufacturer data are not available.

(5) Blowdown vent stacks. Calculate fugitive emissions from blowdown vent stacks as follows:

(i) Calculate the total volume (including, but not limited to pipelines and vessels) between isolation valves (\( V_v \) in Equation A-1.4 of this subpart).

(ii) Retain logs of the number of blowdowns for each equipment type.

(iii) Calculate the total annual fugitive emissions using the following Equation A-1.4 of this section:

\[ E_{s,n} = N \* V_v \]  
(Eq. A-1.4)

Where:
\( E_{a,n} \) = Natural gas fugitive emissions at ambient conditions from blowdowns.
\( N \) = Number of blowdowns for the equipment in reporting year.
\( V_v \) = Total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves.

(iv) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.
(v) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(6) Dehydrator vent stacks. Calculate fugitive emissions from a dehydrator vent stack using a simulation software packages, such as GLYCalc™. Any standard simulation software may be used provided it accounts for the following parameters:
(i) Feed natural gas flow rate.
(ii) Feed natural gas water content.
(iii) Outlet natural gas water content.
(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(v) Absorbent circulation rate.
(vi) Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(vii) Use of stripping natural gas.
(viii) Use of flash tank separator (and disposition of recovered gas).
(ix) Hours operated.
(x) Wet natural gas temperature, pressure, and composition.

(7) Flare stacks. Calculate fugitive emissions from a flare stack as follows:
(i) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares.
(ii) Calculate volume of natural gas sent to flare from velocity measurement in §A-1, Section 4(j) using manufacturer’s manual for the specific meter used to measure velocity.
(iii) Calculate GHG volumetric fugitive emissions at actual conditions using Equation A-1.5 of this section:

\[
E_{a,i} = V_a \times (1-\eta) \times X_i + (1-K)^*\eta^*V_a^*Y_j^*R_{j,i} \quad \text{(Eq. A-1.5)}
\]

Where:
\( E_{a,i} \) = Annual fugitive emissions from flare stack.
\( V_a \) = Volume of natural gas sent to flare stack determined from §A-1, Section 4(j)(1).
\( \eta \) = Percent of natural gas combusted by flare (default is 95 percent for non-steam aspirated flares and 98 percent for steam aspirated or air injected flares).
\( X_i \) = Concentration of GHG i in the flare gas determined from §A-1, Section 4(j)(1).
\( Y_j \) = Concentration of natural gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus).
R_{j,i} = \text{Number of carbon atoms in the natural gas hydrocarbon constituent } j; 1 \text{ for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).} \\
K = “1” \text{ when GHG } i \text{ is CH}_4 \text{ and “0” when GHG } i \text{ is CO}_2.

(iv) Calculate GHG volumetric fugitive emissions at standard conditions using Equation A-1.6 of this section.

\[
E_{r,j} = \frac{E_{s,i} \cdot (460 + T_s) \cdot P_s}{(460 + T_a) \cdot P_i} \quad \text{(Eq. A-1.6)}
\]

Where:

\(E_{s,i}\) = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.
\(E_{a,i}\) = Natural gas volumetric fugitive emissions at actual conditions.
\(T_s\) = Temperature at standard conditions (°F).
\(T_a\) = Temperature at actual emission conditions (°F).
\(P_s\) = Absolute pressure at standard conditions (inches of Hg).
\(P_a\) = Absolute pressure at ambient conditions (inches of Hg).

(v) Calculate both CH\(_4\) and CO\(_2\) mass fugitive emissions from volumetric CH\(_4\) and CO\(_2\) fugitive emissions using calculations in paragraph (g) of this section.

(8) Storage tanks. Calculate fugitive emissions from a storage tank as follows:

(i) Calculate the total annual hydrocarbon vapor fugitive emissions using Equation A-1.7 of this section:

\[
E_{a,h} = Q \times ER \quad \text{(Eq. A-1.7)}
\]

Where:

\(E_{a,h}\) = Hydrocarbon vapor fugitive emissions at actual conditions.
\(Q\) = Storage tank total annual throughput.
\(ER\) = Measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel) determined from §A-1, Section 4(j)(2).

(ii) Estimate hydrocarbon vapor volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Estimate CH\(_4\) and CO\(_2\) volumetric fugitive emissions from volumetric hydrocarbon fugitive emissions using Equation A-1.8 of this section.

\[
E_{z,j} = E_{z,h} \cdot M_i \quad \text{(Eq. A-1.8)}
\]
Where:

\( E_{s,i} \) = GHG \( i \) (either \( \text{CH}_4 \) or \( \text{CO}_2 \)) volumetric fugitive emissions at standard conditions.

\( E_{s,h} \) = Hydrocarbon vapor volumetric fugitive emissions at standard conditions.

\( M_i \) = Mole percent of a particular GHG \( i \) in the hydrocarbon vapors; hydrocarbon vapor analysis shall be conducted in accordance with ASTM D1945-03.

(iv) Estimate \( \text{CH}_4 \) and \( \text{CO}_2 \) mass fugitive emissions from GHG volumetric fugitive emissions using calculations in paragraph (g) of this section.

(9) Compressor wet seal degassing vents. Calculate fugitive emissions from compressor wet seal degassing vents as follows:

(i) Calculate volume of natural gas sent to vent from velocity measurement in §A-1, Section 4 (j) using manufacturer’s manual for the specific meter used to measure velocity.

(ii) Calculate natural gas volumetric fugitive emissions at standard conditions using calculations in paragraph (e) of this section.

(iii) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in paragraphs (f) and (g) of this section.

(e) Calculate natural gas volumetric fugitive emissions at standard conditions by converting ambient temperature and pressure of natural gas fugitive emissions to standard temperature and pressure natural using Equation A-1.9 of this section.

\[
E_{s,n} = \frac{E_{a,n} \times (460 + T_s) \times P_s}{(460 + T_a) \times P_a} \quad \text{(Eq. A-1.9)}
\]

Where:

\( E_{s,n} \) = Natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions.

\( E_{a,n} \) = Natural gas volumetric fugitive emissions at actual conditions.

\( T_s \) = Temperature at standard conditions (°F).

\( T_a \) = Temperature at actual emission conditions (°F).

\( P_s \) = Absolute pressure at standard conditions (inches of Hg).

\( P_a \) = Absolute pressure at ambient conditions (inches of Hg).

(f) Calculate GHG volumetric fugitive emissions at standard conditions as specified in paragraphs (f)(1) and (2) of this section.

(1) Estimate \( \text{CH}_4 \) and \( \text{CO}_2 \) fugitive emissions from natural gas fugitive emissions using Equation A-1.10 of this section.

\[
E_{s,j} = E_{s,n} \times M_j \quad \text{(Eq. A-1.10)}
\]

Where:

\( E_{s,i} \) = GHG \( i \) (either \( \text{CH}_4 \) or \( \text{CO}_2 \)) volumetric fugitive emissions at standard conditions.

\( E_{s,n} \) = Natural gas volumetric fugitive emissions at standard conditions.
M_i = Mole percent of GHG i in the natural gas.

(2) For Equation A-1.10 of this section, the mole percent, M_i, shall be the annual average mole percent for each facility, as specified in paragraphs (f)(2)(i) through (vi) of this section.

(i) GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.

(ii) GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.

(iii) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(iv) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(v) GHG mole percent in natural gas stored in LNG storage facilities.

(vi) GHG mole percent in natural gas stored in LNG import and export facilities.

(vii) GHG mole percent in transmission pipeline natural gas that is passed to a natural gas distribution system.

(g) Calculate GHG mass fugitive emissions at standard conditions by converting the GHG volumetric fugitive emissions into mass fugitive emissions using Equation A-1.11 of this section.

\[
Mass_{z,i} = E_{z,i} \cdot \rho_i \quad \text{(Eq. A-1.11)}
\]

Where:

\[
Mass_{z,i} = \text{GHG i (either CH}_4 \text{ or CO}_2 \text{) mass fugitive emissions at standard conditions.}
\]

\[
E_{z,i} = \text{GHG i (either CH}_4 \text{ or CO}_2 \text{) volumetric fugitive emissions at standard conditions.}
\]

\[
\rho_i = \text{Density of GHG i ; 1.87 kg/m}^3 \text{ for CO}_2 \text{ and 0.68 kg/m}^3 \text{ for CH}_4.
\]

(h) Emissions from gas transmission and distribution lines from line maintenance operations

(1) Emissions CH_4 and CO_2 as a result of pipeline cleaning and inspection with pigs shall be estimated based on the volume of gas required to insert the pig at the pig injection station plus the volume required to eject the pig from the pipeline at pig retrieval stations. The CH_4 and CO_2 emissions shall be based on the measured mole fractions of CH_4 and CO_2 content measured per §A-1, Section 4(j)(1)(iii).

(2) Emissions of CH_4 and CO_2 as a result of pipe maintenance that requires a pipe segment to be purged of natural gas. These emissions shall be calculated based on the volume of the pipe between shut off valves the pressure of the gas inside the pipe at the time of purging, and the mole fractions of the natural gas CH_4 and CO_2 content measured per §A-1, Section 4(j)(1)(iii).

(i) Converting mass of CH_4 and CO_2 emitted to CO_2e

\[
CO_{2e} = 21 \times \text{Mass}_{CH_4} + \text{Mass}_{CO_2} \quad \text{Eq. A-1.12}
\]
Where:

\[ \text{CO}_2e = \text{total metric tonnes of CH}_4 \text{ and CO}_2 \text{ expressed as carbon dioxide equivalent} \]
\[ \text{MassCH}_4 = \text{the mass in metric tons of CH}_4 \text{ contained in the gas emitted from all units and sources covered in this appendix.} \]
\[ \text{MassCO}_2 = \text{the mass in metric tons of CO}_2 \text{ contained in the gas emitted from all units and sources covered in this appendix.} \]
\[ 21 = \text{Global warming potential of CH}_4 \]

§A-1, Section 4 Monitoring and QA/QC requirements.

(a) You must use the methods described in paragraphs (d) or (e) in this section to conduct annual leak detection of fugitive emissions from all sources listed in §A-1, Section 2 (a), whether in operation or on standby. If fugitive emissions are detected for sources listed in paragraph (b) of this section, you must use the measurement methods described in paragraph (c) of this section to measure emissions from each source with fugitive emissions.

(b) You shall use detection instruments described in paragraphs (d) and (e) of this section to monitor the following fugitive emissions:

1. Centrifugal compressor dry seals fugitive emissions.
2. Centrifugal compressor wet seals fugitive emissions.
3. Compressor fugitive emissions.
4. LNG import and export facility fugitive emissions.
5. LNG storage station fugitive emissions.
7. Open-ended lines (OELs) fugitive emissions.
8. Pump seals fugitive emissions.
11. Processing facility fugitive emissions.
12. Reciprocating compressor rod packing fugitive emissions.
13. Storage station fugitive emissions.
14. Transmission station fugitive emissions.
15. Storage wellhead fugitive emissions.

(c) You shall use a high volume sampler, described in paragraph (f) of this section, to measure fugitive emissions from the sources detected in §A-1, Section 4(b), except as provided in paragraphs (c)(1) and (2) of this section:

1. Where high volume samplers cannot capture all of the fugitive emissions, you shall use calibrated bags described in paragraph (g) of this section or meters described in paragraph (h) of this section to measure the following fugitive emissions:
   (i) Open-ended lines (OELs).
   (ii) Centrifugal compressor dry seals fugitive emissions.
   (iii) Centrifugal compressor wet seals fugitive emissions.
   (iv) Compressor fugitive emissions.
   (v) Pump seals fugitive emissions.
   (vi) Reciprocating compressor rod packing fugitive emissions.
(vii) Flare stacks and storage tanks, except that you shall use meters in combination with engineering estimation methods to calculate fugitive emissions.

(2) Use hot wire anemometer to calculate fugitive emissions from centrifugal compressor wet seal degassing vents and flares where it is unsafe or too high a flow rate to use calibrated bags.

(d) Infrared Remote Fugitive Emissions Detection.

(1) Use infrared fugitive emissions detection instruments that can identify specific equipment sources as emitting. Such instruments must have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere.

(2) If you are using instruments that visually display an image of fugitive emissions, you shall inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions at least once annually.

(3) If you are using any other infrared detection instruments, such as those based on infrared laser reflection, you shall monitor all potential emission points at least once annually.

(4) Perform fugitive emissions detection under favorable conditions, including but not limited to during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument.

(5) Use fugitive emissions detection and measurement instrument manuals to determine optimal operating conditions.

(e) Use organic vapor analyzers (OVAs) for all fugitive emissions detection that are safely accessible at close-range.

(1) Check each potential emissions source, all joints, connections, and other potential paths to the atmosphere for emissions.

(2) Evaluate the lag time between the instrument sensing and alerting caused by the residence time of a sample in the probe shall be evaluated; upon alert, the instrument shall be slowly retraced over the source to pinpoint the location of fugitive emissions.


(f) Use a high volume sampler to measure only cold and steady emissions within the capacity of the instrument.

(1) A trained technician shall conduct measurements. The technician shall be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, including, but not limited to, positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer’s manual.

(3) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §A-1, Section 3(f) and (g).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer’s instructions for calibration.
(g) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured for measurement.

1. Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag.
2. Perform three measurements of the time required to fill the bag; report the emissions as the average of the three readings.
3. Estimate natural gas volumetric emissions at standard conditions using calculations in §A-1, Section 3(e).
4. Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §A-1, Section 3(f) and (g).
5. Obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.

(h) Channel all emissions from a single source directly through the meter when using metering (e.g., rotameters, turbine meters, and others).

1. Use an appropriately sized meter so that the flow does not exceed the full range of the meter in the course of measurement and conversely has sufficient momentum for the meter to register continuously in the course of measurement.
2. Estimate natural gas volumetric fugitive emissions at standard conditions using calculations in §A-1, Section 3(f).
3. Estimate CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in §A-3(f) and (g).
4. Calibrate the meter using either one of the two methods provided as follows:
   (i) Develop calibration curves by following the manufacturer’s instruction.
   (ii) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST). Determine correction factors for the flow meter according to the manufacturer’s instructions. Record deviations from the correct reading at several flow rates. Plot the data points, comparing the flowmeter output to the actual flowrate as determined by the master weigh scale and use the difference as a correction factor.

(i) Where engineering estimation as described in §A-1, Section 3 is not possible, use direct measurement methods as follows:

1. If manufacturer data on pneumatic pump natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. Determine the volume of liquid being pumped from the manufacturer’s manual to provide the amount of natural gas emitted per unit of liquid pumped.
   (i) Record natural gas conditions (temperature and pressure) and convert natural gas emission per unit volume of liquid pumped at actual conditions into natural gas emission per pumping cycle at standard conditions using Equation A-1.9 of §A-1, Section 3.
   (ii) Calculate annual fugitive emissions from the pump using Equation A-1.1, by replacing the manufacturer’s data on emission (variable Fₛ) in the Equation with the standard conditions natural gas emission calculated in §A-1, Section 4(i)(1)(i).
(iii) Estimate CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in §A-1, Section 3(f) and (g).

(2) If manufacturer data on pneumatic manual valve actuator device natural gas emission are not available, conduct a one-time measurement to determine natural gas emission per actuation using a calibrated bag for each pneumatic device per actuation.

(i) Record natural gas conditions (temperature and pressure) and convert natural gas emission at actual conditions into natural gas emission per actuation at standard conditions using Equation A-1.9 of this subpart.

(ii) Calculate annual fugitive emissions from the pneumatic device using Equation A-1.2 of this section, by replacing the manufacturer’s data on emission (variable \( A_e \)) in the Equation with the standard conditions natural gas emission calculated in §A-1, Section 4(i)(2)(i).

(iii) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas fugitive emissions using calculations in §A-1, Section 3(f) and (g).

(3) If manufacturer data on natural gas driven pneumatic valve bleed rate is not available, conduct a one-time measurement to determine natural gas bleed rate using a high volume sampler or calibrated bag or meter for each pneumatic device.

(i) Record natural gas conditions (temperature and pressure) to convert natural gas bleed rate at actual conditions into natural gas bleed rate at standard conditions using Equation A-1.9 of this subpart.

(ii) Calculate annual fugitive emissions from the pneumatic device using Equation A-1.3 of this subpart, by replacing the manufacturer’s data on bleed rate (variable \( B \)) in the equation with the standard conditions bleed rate calculated in §A-1, Section 4(i)(3)(i).

(iii) Estimate CH₄ and CO₂ volumetric and mass fugitive emissions from volumetric natural gas fugitive emissions using calculations in §A-1, Section 3(f) and (g).

(j) Parameters for calculating emissions from flare stacks, compressor wet seal degassing vents, transmission and distribution system maintenance activities, and storage tanks.

(1) Estimate fugitive emissions from flare stacks and compressor wet seal degassing vents as follows:

(i) Insert flow velocity measuring device (such as hot wire anemometer or pitot tube) directly upstream of the flare stack or compressor wet seal degassing vent to determine the velocity of gas sent to flare or vent.

(ii) Record actual temperature and pressure conditions of the gas sent to flare or vent.

(iii) Sample representative gas to the flare stack or compressor wet seal degassing vent every quarter to evaluate the composition of GHGs present in the stream. Record the average of the most recent four gas composition analyses, which shall be conducted using ASTM D1945-03.

(2) Estimate fugitive emissions from storage tanks as follows:

(i) Measure the hydrocarbon vapor emissions from storage tanks using a flow meter described in paragraph (h) of this section for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.

(ii) Record the net (related to working loss) and gross (related to flashing loss) input of the storage tank during the test period.
(iii) Record temperature and pressure of hydrocarbon vapors emitted during the test period.
(iv) Collect a sample of hydrocarbon vapors for composition analysis
(k) Component fugitive emissions sources that are not safely accessible within the operator’s arm’s reach from the ground or stationary platforms are excluded from the requirements of this section.
(1) Determine annual emissions assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero detection in the current reporting period and continuing until the fugitive emissions is repaired.

§ A-1, Section 5 Data reporting requirements.
In addition to the information required by WAC 173-441-120, each annual report must report emissions data as specified in this section
(a) Annual emissions reported separately for each of the operations listed in paragraphs (a)(1) through (6) of this section. Within each operation, emissions from each source type must be reported in the aggregate. For example, an underground natural gas storage facility with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.
(1) Offshore petroleum and natural gas production facilities.
(2) Onshore natural gas processing facilities.
(3) Onshore natural gas transmission compression facilities.
(4) Underground natural gas storage facilities.
(5) Liquefied natural gas storage facilities.
(6) Liquefied natural gas import and export facilities.
(b) Emissions reported separately for standby equipment.
(c) Emissions calculated for these sources shall assume no CO₂ capture and transfer off site.
(d) Activity data for each aggregated source type level for which emissions are being reported.
(e) Engineering estimate of total component count.
(f) Total number of compressors and average operating hours per year for compressors for each operation listed in paragraphs (a)(1) through (6) of this section.
(g) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (6) of this section.
(h) Specification of the type of any control device used, including flares, for any source type listed in §A-1, Section 2(a).
(i) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether they are producing oil, gas, or both.
(j) Detection and measurement instruments used.

§A-1, Section 6 Definitions.
All terms used in Appendix A-1, Section 1 have the meaning given below. If not defined here the terms have the same meaning given in WAC 173-441-010 and the Washington Clean Air Act.

“Air injected flare” means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e. high noncombustible component content).
“Bleed rate” means the rate at which natural gas flows continuously or intermittently from a process measurement instrument to a valve actuator controller where it is vented (bleeds) to the atmosphere.

“Blowdown” means manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.

“Blowdown vent stack fugitive emissions” mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and Emergency Shut-Down system testing.

“Boil-off gas” means natural gas that vaporizes from liquefied natural gas in storage tanks.

“Centrifugal compressor” means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

“Centrifugal compressor dry seals” mean a series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

“Centrifugal compressor dry seals fugitive emissions” mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

“Centrifugal compressor wet seals” mean a series of rings around the compressor shaft where it exits the compressor case, that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere.

“Centrifugal compressor wet seals fugitive emissions” mean natural gas released from the seal face around the rotating shaft where it exits one or both ends of the compressor case PLUS the natural gas absorbed in the circulating seal oil and vented to the atmosphere from a seal oil degassing vessel or sump before the oil is recirculated, or from a seal oil containment vessel vent.

“Component”, for the purposes of Appendix A-1 only, means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

“Compressor” means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas (i.e. compression ratio higher than 1.5).
“Compressor fugitive emission” mean natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.

“Condensate” means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

“Connector” means but is not limited to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

“Dehydrator” means, for the purposes of this rule, a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

“Dehydrator vent stack fugitive emissions” means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

“De-methanizer” means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (ethane, propane, butane, pentane-plus) in feed natural gas stream.

“Engineering estimation” means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

“Equipment” means but is not limited to each pump, compressor, pipe, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, tank, vessel, and instrumentation system in natural gas or liquid service; and any control devices or systems referenced by this subpart.

“Equipment chambers” mean the total natural gas-containing volume within any equipment and between the equipment isolation valves.

“Export” means to transport a product from inside Washington State to persons outside Washington State, excluding United States military bases and ships for onboard use.

“Exporter” means any person, company, or organization of record that contracts to transfer a product from Washington State to another state or country or that transfers products to an
affiliate in another state or country, excluding transfers to United States military bases and ships for on-board use.

“Flare” means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

“Flare combustion efficiency” means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed 95 percent for non-aspirated field flares and 98 percent for steam or air aspirated flares.

“Flare stack” means a device used to provide a safe means of combustible natural gas disposal from routine operations, upsets, or emergencies via combustion of the natural gas in an open, normally elevated flame.

“Flare stack fugitive emissions” means the CH4 and CO2 content of that portion of natural gas (typically 5 percent in non-aspirated field flares and 2 percent in steam or air aspirated flares) that passes through flares un-combusted and the total CO2 emissions of that portion of the natural gas that is combusted.

“Fugitive emissions” means unintentional equipment emissions of methane and/or carbon dioxide containing natural gas or hydrocarbon gas (not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. Fugitive emissions also mean CO2 emissions resulting from combustion of natural gas in flares.

“Gas conditions” mean the actual temperature, volume, and pressure of a gas sample.

“Gathering and boosting station” means a station used to gather natural gas from well or field pipelines for delivery to a natural gas processing facilities or central point. Stations may also provide compression, dehydration, and/or treating services.

“Importer” means any person, company, or organization of record that for any reason brings a product (natural gas or LNG) into the United States from a foreign country. An importer includes the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term also includes, as appropriate: (1) The consignee. (2) The importer of record. (3) The actual owner. (4) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

“Infrared remote fugitive emissions detection instrument” means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere. For the purpose of this rule, it must detect the presence of methane.


“Liquefied natural gas (LNG)” means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

“Liquefied natural gas import and export facilities” mean onshore and/or offshore facilities that send out exported or receive imported liquefied natural gas, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

“Liquefied natural gas storage facilities” means an onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

“LNG import and export facility fugitive emissions” mean natural gas releases from valves, connectors, storage tanks, flanges, open-ended lines, pressure relief valves, boil-off-gas recovery, send outs (pumps and vaporizers), packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

“LNG storage station fugitive emissions” mean natural gas releases from valves, connectors, flanges, open-ended lines, storage tanks, pressure relief valves, liquefaction process units, packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

“Mcf” means thousand cubic feet.

“Natural gas” means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth’s surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of Appendix A-1, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

“Natural gas distribution system” means the natural gas piping system between the gas distribution pressure let-down metering and regulating stations and the customer’s gas meter. The distribution network includes all valves, pressure regulating stations, compression stations, and natural gas distribution fugitive emission sources.
“Natural gas driven pneumatic manual valve actuator device” means valve control devices that use pressurized natural gas to provide the energy required for an operator to manually open, close, or throttle a liquid or gas stream. Typical manual control applications include, but are not limited to, equipment isolation valves, tank drain valves, pipeline valves.

“Natural gas driven pneumatic manual valve actuator device fugitive emissions” means natural gas released due to manual actuation of natural gas pneumatic valve actuation devices, including, but not limited to, natural gas diaphragm and pneumatic-hydraulic valve actuators.

“Natural gas driven pneumatic pump” means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

“Natural gas driven pneumatic pump fugitive emissions” means natural gas released from pumps that are powered or assisted by pressurized natural gas.

“Natural gas driven pneumatic valve bleed device” means valve control devices that use pressurized natural gas to transmit a process measurement signal to a valve actuator to automatically control the valve opening. Typical bleeding process control applications include, but are not limited to, pressure, temperature, liquid level, and flow rate regulation.

“Natural gas driven pneumatic valve bleed devices fugitive emissions” means the continuous or intermittent release of natural gas from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g. liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

“Natural gas liquids (NGL)” mean those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally, such liquids consist of primarily ethane, propane, butane, and isobutane, primarily pentanes produced from natural gas at lease separators and field facilities. For the purposes of subpart NN only, natural gas liquids does not include lease condensate. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

“Natural gas processing facilities” are engaged in the extraction of natural gas liquids from produced natural gas; fractionation of mixed natural gas liquids to natural gas products; and removal of carbon dioxide, sulfur compounds, nitrogen, helium, water, and other contaminants. Natural gas processing facilities also encompass gathering and boosting stations that include equipment to phase-separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility.

“Natural gas products” means products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus.

“Natural gas transmission compression facility” means any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into
storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids. NIST means the United States National Institute of Standards and Technology.

“Non-steam aspirated flare” means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

“Offshore” means tidal-affected borders of the U.S. lands, both state and Federal, adjacent to oceans, bays, lakes or other normally standing water.

“Offshore petroleum and natural gas production facilities” means any platform structure, floating in the ocean or lake, fixed on ocean or lake bed, or located on artificial islands in the ocean or lake, that houses equipment to extract hydrocarbons from ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipments for separation of liquids from natural gas components, dehydration of natural gas, extraction of H2S and CO2 from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters.

“Offshore platform pipeline fugitive emissions” means natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities.

“Open-ended line fugitive emissions” means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

“Open-ended valve or Lines (OELs)” means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid (such as pressurized natural gas) and one side open to atmosphere, either directly or through open piping.

“Organic vapor analyzer (OVA)” means an organic monitoring device that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

“Platform fugitive emissions” means natural gas released from equipment and equipment components including valves, pressure relief valves, connectors, tube fittings, open-ended lines, ports, and hatches. This does not include fugitive emissions from equipment and components reported elsewhere for this rule.

“Processing facility fugitive emissions” means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-
down) system fugitive emissions, packing and gaskets in natural gas processing facilities. This does not include fugitive emissions from equipment and components reported elsewhere for this rule, such as compressor fugitive emissions; acid gas removal, blowdown, wet seal oil degassing, and dehydrator vents; and flare stacks.

“Production process unit” means equipment used to capture a carbon dioxide stream.

“Pump seals” means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

“Pump seal fugitive emissions” means natural gas released from the seal face between the pump internal chamber and the atmosphere.

“Reciprocating compressor” means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

“Reciprocating compressor rod packing” means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

“Reciprocating compressor rod packing fugitive emissions” means natural gas released from a connected tubing vent and/or around a piston rod where it passes through the rod packing case. It also includes emissions from uncovered distance piece, rod packing flange (on each cylinder), any packing vents, cover plates (on each cylinder), and the crankcase breather cap.

“Re-condenser” means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

“Re-gasification” means the process of vaporizing liquefied natural gas to gaseous phase natural gas.

“Sour natural gas” means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

“Standard conditions or standard temperature and pressure (STP)” means 60 degrees Fahrenheit and 14.7 pounds per square inch absolute.

“Steam aspirated flare” means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

“Storage station fugitive emissions” means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system
emissions, packing and gaskets in natural gas storage station. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

“Storage tank fugitive emissions” means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

“Storage wellhead fugitive emissions” means natural gas released from storage station wellhead components including but not limited to valves, OELs, connectors, flanges, and tube fittings.

“Sub-surface” or “subsurface facility” means for the purposes of this rule, a natural gas facility, such as a pipeline and metering and regulation station in a closed vault below the land surface of the Earth.

“Tanker unloading” means pumping of liquid hydrocarbon (e.g. crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

“Transmission compressor station fugitive emissions” means natural gas released from all components including but not limited to valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas transmission compressor stations. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule, such as compressor fugitive emissions.

“Transmission pipeline” means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

“Underground natural gas storage facility” means a subsurface facility, including but not limited to depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at a natural gas underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.

“Valve” means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

“Vapor recovery system” means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.
“Vaporization unit” means a process unit that performs controlled heat input to vaporize liquefied natural gas to supply transmission and distribution pipelines, or consumers with natural gas.

“Wellhead” means the piping, casing, tubing and connected valves protruding above the Earth’s surface for an oil and/ or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

“Wet natural gas” means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as “wet gas”.