

# Western Climate Initiative



## Final Essential Requirements of Mandatory Reporting

### 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions

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December 21, 2011

Amended February 10, 2012 to include #7 in the list of errata changes

<b>1</b>	<b>Introduction .....</b>	<b>2</b>
<b>2</b>	<b>Harmonization Principles .....</b>	<b>3</b>
2.1	For U.S. Jurisdictions .....	3
2.2	For Canadian Jurisdictions .....	3
<b>3</b>	<b>Harmonization Approach .....</b>	<b>4</b>
3.1	For U.S. Jurisdictions .....	4
3.2	For Canadian Jurisdictions .....	4
3.3	Verification .....	5
3.4	Missing Data Procedures .....	5
<b>4</b>	<b>Summary of Changes to the Quantification Methods.....</b>	<b>5</b>
<b>5</b>	<b>Errata Changes to Quantification Methods.....</b>	<b>9</b>

# 1 Introduction

This document and the attachments provide an overview of the 2011 amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions (referred to as the 2011 Canadian ERs).

The WCI Essential Requirements for Mandatory Reporting (ERs) were [first published on July 15, 2009](#) and then amended in 2010 to create [U.S. \(published November 12, 2010\)](#) and [Canadian versions](#) (published December 17, 2010). The 2010 amendments were a result of WCI partners being concerned that the existence of two different reporting systems in a WCI state could result in the imposition of duplicative or conflicting reporting obligations on facilities subject to both programs. The Partners therefore directed the WCI Reporting Committee to develop amended ERs that are harmonized with the EPA rule. The November 12, 2010 U.S. ERs took the form of a mark-up of the U.S. Environmental Protection Agency (EPA) rule showing the changes to the EPA program that are needed to support a cap-and-trade program.

To ensure consistency and harmonization with the U.S. ERs in Canadian Partner jurisdictions, on December 17, 2010, the WCI published the [“Final Essential Requirements for Mandatory Reporting – Canadian Harmonization Version”](#) (the “2010 Canadian ERs”). The 2010 Canadian ERs adopted consistent quantification methods for use in Canadian Partner jurisdictions for all source categories. Significant updates were made to a number of quantification sections and the two oil and gas methods were published for the first time.

Quantification methods for the oil and gas sector are evolving in the U.S. and some technical elements of the U.S. EPA November 8, 2010 Subpart W (Petroleum and Natural Gas Systems) publication were not reflected in the 2010 Canadian ERs. WCI’s Reporting Committee has worked through 2011, with the help of technical experts, to develop cap and trade quality reporting requirements for sources covered by Subpart W for use in both Canadian and U.S. jurisdictions. In addition, WCI also retained a technical expert to refine the biomass emission factors.

Stakeholder comments on proposed changes to the ERs were sought by the WCI Partner jurisdictions using informal means. This included communications on technical issues about the methods, consultation with individual companies and consultation with industry groups.

The 2011 Canadian ERs make both minor amendments and broader harmonization updates to the two oil and gas quantification sections. No changes are made to the general provisions of the ERs. The updates replace specific sections or clauses of the 2010 Canadian ERs and have been designed to be adopted for use by Canadian jurisdictions at the earliest point feasible in the jurisdiction. For those jurisdictions with direct references to the WCI Canadian ERs, adoption would be for 2012 calendar year emissions, as reported in 2013.

Further work within WCI is expected in 2012 given that the U.S. EPA released a revised Subpart W on December 2, 2011. WCI plans to review the latest Subpart W revisions and may consult with stakeholders on further potential updates (though less extensive) to the two oil and gas quantification sections in 2012.

Further evaluation of “reporting only” sources within the scope of the methods in the ERs, particularly for specific oil and gas sources, will be occurring, along with analysis and incorporation of further changes needed to include such sources within a cap and trade system.

This document and the attachments provide an overview of the 2011 amendments made to WCI Final Essential Requirements of Mandatory Reporting for harmonization of reporting for Canadian jurisdictions. Only those quantification methods where there are significant changes are re-published in full in this package. Where only a few modifications were made to a method, errata changes made are listed in Section 5 below.

## **2 Harmonization Principles**

### **2.1 For U.S. Jurisdictions**

The harmonization principles for U.S. jurisdictions are outlined in the “Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule”<sup>1</sup>.

### **2.2 For Canadian Jurisdictions**

In developing harmonized ERs that modify the existing ERs for use in Canadian Partner jurisdictions, the WCI Reporting Committee adhered to the following principles:

1. A Canadian facility should apply the equivalent functions, equations, sampling protocols and measurement criteria as U.S. facilities subject to the U.S. version of the harmonized ERs. This means that the harmonized ERs will achieve the same level of reporting accuracy for Canadian and U.S. facilities, but the U.S. version may require more data elements to be reported to harmonize with the EPA rule.
2. The quantification methods included in the harmonized ERs must remain sufficiently reliable and accurate to be employed in a GHG cap-and-trade program.

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<sup>1</sup> <http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule>

3. The WCI reporting system must remain suitable for use in Canadian Partner jurisdictions. For example, it must allow reporting in metric as well as English units and must where necessary include Canada-specific emission factors.
4. The harmonized ERs should facilitate harmonization with Canadian federal reporting. Some Canadian Partner jurisdictions are working with Environment Canada to develop a one-window reporting tool for provincial and national GHG reporting requirements.

WCI intends to follow the same principles with regard to future additions or amendments to the EPA rule, such as the recently finalized Subpart W for the oil and gas industry, and the recently proposed revisions to Subpart A (general provisions) and several source category subparts.<sup>2</sup> WCI will review each proposed revision to assess its suitability for cap-and-trade before incorporating it into the harmonized ERs.

## **3 Harmonization Approach**

### **3.1 For U.S. Jurisdictions**

The harmonization approach for U.S. jurisdictions is outlined in the “Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule”<sup>3</sup>.

### **3.2 For Canadian Jurisdictions**

For the Canadian jurisdictions, the key requirement is that the WCI reporting system as a whole require the use of comparable methodologies and produce comparable results for facilities of the same type, so that “a tonne is a tonne” in both the U.S. and Canada. For Canadian jurisdictions it is not nearly as important to avoid small differences between the ERs and the EPA rule as it is for the U.S. jurisdictions, where such differences could create a risk of inadvertent non-compliance.

Canadian Partners have developed Canadian ERs that can be applied within the provincial legal frameworks. U.S. states also work within their legal framework by referencing the EPA rules and making the specific amendments needed to ensure cap and trade quality data. This latest Canadian ERs conforms in substance with reporting requirements adopted by the US WCI Partners (e.g., California). In addition, the Canadian ERs facilitate harmonization with Environment Canada and the use of Canada-specific reporting metrics and factors.

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<sup>2</sup> Pre-publication version posted on July 20, 2010 at: <http://www.epa.gov/climatechange/emissions/technical-corrections.html#revisions>

<sup>3</sup> <http://www.westernclimateinitiative.org/news-and-updates/125-harmonization-of-essential-requirements-for-mandatory-reporting-in-us-jurisdictions-with-epa-mandatory-reporting-rule>

### 3.3 Verification

Consistent with the Design Recommendations for the WCI Regional Cap-and-Trade Program, the harmonized U.S. and Canadian ERs require third party verification of emission reports for entities and facilities with emissions equal to or greater than 25,000 tonnes CO<sub>2</sub>e. No revisions to the verification rule are made in the 2011 amendments to the Canadian ERs.

The amount of data to be reported for Canadian jurisdictions has been kept at a reduced level compared to that which is required to be reported to the EPA. This reflects the WCI third party verification requirements for emissions reports instead of the reliance on internal verification.

### 3.4 Missing Data Procedures

The Canadian harmonized ERs incorporate the EPA missing data procedures. During initial implementation of the cap-and-trade program, however, the WCI intends to revisit this issue. The WCI is investigating how the EPA missing data procedures can be modified to be more consistent with the needs of a cap-and-trade program while adhering to the harmonization principles and intends to propose and implement the necessary modifications in time for the 2013 reporting year.

## 4 Summary of Changes to the Quantification Methods

The following table summarizes the changes to the quantification methods that the WCI is publishing for Canadian jurisdictions. The specific language for the amendments is made in Section 5 and the attached amended quantification methods.

Section	Change to WCI Rule	Rationale
WCI.023	Updates to CO <sub>2</sub> equations and parameters	Clarification of biomass and solid waste reporting, other clarifications
WCI.024	Updates to CH <sub>4</sub> and N <sub>2</sub> O equations, creation of new coal-specific equations.	Simplification and clarification of equations
WCI.025	Refinement to sampling, analysis and measurement procedures, including calibration.	Simplification and clarification

Section	Change to WCI Rule	Rationale
WCI.027	Updated biomass emission factors	Review of differences between various published biomass emission factors 2010 sample data.
WCI.020 / WCI.040 and WCI.210	Clarification of where to report black liquor emissions	Avoidance of double-counting
WCI.160 and WCI.240	Errata changes  Addition of method for sampling waste-based fuels	Clarification  Technical review
WCI.040 and WCI.090	Errata changes	Clarification
WCI.352  WCI.362	Clarified and updated application of different quantification methods  Updated information to be reported	Clarification and updates  Updates
WCI.353 WCI.363 (throughout)	Simplification of equations to most basic form	Simplification and clarification
WCI.353(a), (a.1), (b), (b.1)  WCI.363(a), (a.1), (b), (b.1)	Split pneumatic devices to four categories  Extended phase-in and clarified language for metering of high bleed devices and pumps  Clarified reporting of compressor starters	Rule clarity  Extension of phase-in, rule clarity  Clarification
WCI.363(c)	Incorporated EPA 98.233(d) methods 1 and 2 and revised existing WCI equation	Addition of options, reduced error in main acid gas removal equation, harmonization within WCI.

Section	Change to WCI Rule	Rationale
WCI.363(f)	Incorporated EPA 98.233(g) methods	Harmonization within WCI
WCI.353 (c) WCI.363(g)	Updated equation to be consistent with EPA	Harmonization within WCI
WCI.353 (c.1) WCI.363 (g.1)	Added third party line hit method	Completeness of reporting
WCI.363 (h)	Removed limitation on choice of method	Ease of use
WCI.353 (m) WCI.363(h.1)	Added transmission storage tank method from EPA 98.233(k)	Harmonization within WCI / correction of oversight
WCI.353(e) WCI.363(l)	<p>Identified wet and dry gas seals</p> <p>Allowed application of emission factor for units (in aggregate) &lt;250 hp (WCI.363 only)</p> <p>Added detail of operating modes per EPA language</p>	<p>Clarification, harmonization within WCI</p> <p>Reduced burden for small compressors</p> <p>Harmonization within WCI</p>
WCI.353(f) WCI.363(m)	<p>Added control factor to account for seal gas used as fuel</p> <p>Allowed application of emission factor for units (in aggregate) &lt;250 hp (WCI.363 only)</p>	<p>Accuracy</p> <p>Reduced burden for small compressors</p>

Section	Change to WCI Rule	Rationale
WCI.353(g) and WCI.353(h)  WCI.363(n) and WCI.363(o)	Cross-checked and corrected references to WCI.352 and WCI.362 sections for application of leak detection and population count methods  Clarified requirements for leak detection at small compressor stations	Accuracy   Harmonization within WCI, reduced burden
WCI.363(o)	Correct equation to account for THC factors and multiple service types	Technical correction
WCI.353(j)	Clarified use of known gas composition for transmission and distribution	Clarification, reduced burden
WCI.363(w)	Required use of actual compositions where known.  Indicated that same methodology must be used in subsequent year	Accuracy, use of existing data   Accuracy
WCI.357 WCI.367  Tables	Added table of pneumatic manufacturer average bleed rates  Revised pneumatic emission factors  Revised reference from Clearstone Methodology Manual Table 6 to Table 9	Reduced burden   Harmonization within WCI   Technical correction
WCI.356 WCI.366  Definitions	Revised use of “city gate station” to “metering-regulation station”  Clarified split between custody transfer and non-custody transfer  Other updates	Clarification and technical corrections

## 5 Errata Changes to Quantification Methods

The following is a list of the errata changes made to quantification methods other than WCI.020 (General Stationary Combustion), WCI.350 (Natural Gas Transmission and Distribution) and WCI.360 (Petroleum and Natural Gas Production and Natural Gas Processing in the Final Essential Requirements of Mandatory Reporting (for harmonization of reporting for Canadian jurisdictions). No changes are made to the general provisions (WCI.1 to WCI.9) as published by the WCI on July 15, 2009 and updated on December 17, 2010. Errata changes are effective immediately and are meant to clarify issues for 2011 calendar year reporting and into the future.

1. **Cement Manufacturing:** WCI.094(j) is amended by adding “, and or material balances.” at the end of the provision.
2. **Electricity Generation:** WCI.043(a)(1)(A) is modified to read “... the results of fuel sampling and analysis for the fuel heat value **or carbon content, as applicable**, from the fuel supplier...”.
3. **Electricity Generation and Pulp and Paper Manufacturing.** The following note is placed at the top of the WCI.040 and WCI.210 quantification methods:  
*“Note: CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from spent/pulping liquor combusted to produce electricity in the process of pulp and paper manufacturing should be reported under WCI.210, starting with the 2011 reporting year. Additional reporting requirements that are present in the two quantification methods are maintained independent on the direction of where to report the emissions.”*
4. **Lead Production and Zinc Production:** WCI.164(a)(4) and WCI.244(a)(4) are struck and replaced with the following:
  - (4) For waste-based carbon-containing material, determine the carbon content by either:
    - i. Operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
      - A. To ensure representativeness of waste-based carbon containing material variability, the specific testing plan (e.g. number of test runs, other process variable to keep constant, timing of runs) for these trials must be approved by the jurisdiction.
    - ii. By using the theoretical carbon content of the waste-based carbon containing material as derived using engineering estimation techniques.
5. **Lead Production:** WCI.164(a) is amended by adding the following:
  - (5) A facility may use an appropriate analytical method for determining the carbon content of ore
6. **Lead Production and Zinc Production:** WCI.162(c) and WCI.242(c) are modified to read “... (tonnes C/tonne input material)”
7. Updates to the WCI.28 Tables are applicable starting with 2011 calendar year emissions as they correct emission factors that were in error or had substantive uncertainty.

# Western Climate Initiative



## § WCI.20 GENERAL STATIONARY COMBUSTION

### § WCI.21 Source Category Definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, and any other stationary combustion device that is not specifically addressed under the methods for another source category. This source category does not include portable equipment, emergency generators, and emergency equipment (including emergency flares).

### § WCI.22 Greenhouse Gas Reporting Requirements

*Note: CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from spent/pulping liquor combusted in the process of pulp and paper manufacturing should be reported under WCI.210, starting with the 2011 reporting year.*

Except as noted in the previous paragraph, the emissions data report shall include the following information at the facility level:

- (a) Annual greenhouse gas emissions in tonnes, reported as follows:
  - (1) Total CO<sub>2</sub> emissions for fossil fuels, reported by fuel type.
  - (2) Total CO<sub>2</sub> emissions for biomass, reported by fuel type.
  - (3) Total CH<sub>4</sub> emissions, reported by fuel type.
  - (4) Total N<sub>2</sub>O emissions, reported by fuel type.
- (b) Annual fuel consumption:
  - (1) For gases, report in units of standard cubic meters.
  - (2) For liquids, report in units of kilolitres.
  - (3) For non-biomass solids, report in units of tonnes.
  - (4) For biomass solid fuels, report in units of bone dry tonnes.
- (c) Annual weighted average carbon content of each fuel, if used to compute CO<sub>2</sub> emissions.
- (d) Annual weighted average high heat value of each fuel, if used to compute CO<sub>2</sub> emissions.
- (e) Annual steam in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

## § WCI.23 Calculation of CO<sub>2</sub> Emissions

For each fuel, calculate CO<sub>2</sub> mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e). If a fuel or fuels is not listed in all of Tables 20-1 through 20-7, or in Table C-1 or C-2 of U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as the sum of emissions from these fuels does not exceed 0.5% of total facility emissions. If the sum of emissions from these fuels exceeds 0.5% of total facility emissions, then report emissions from one or more of these fuels as needed so that the sum of emissions from the remaining unlisted fuels does not exceed 0.5% of total facility emissions.

- (a) Calculation Methodology 1. Calculate the annual CO<sub>2</sub> mass emissions for each type of fuel by substituting a fuel-specific default CO<sub>2</sub> emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1 or 20-1a:

$$CO_2 = Fuel \times HHV \times EF \times 0.001 \quad \text{Equation 20-1}$$

$$CO_2 = Fuel \times EF_c \times 0.001 \quad \text{Equation 20-1a}$$

Where:

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions for the specific fuel type (tonnes).  
Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).  
HHV = Default high heat value of the fuel, from Table 20-1 and 20-1a (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).  
EF = Fuel-specific default CO<sub>2</sub> emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO<sub>2</sub>/GJ).  
EF<sub>c</sub> = Fuel-specific default CO<sub>2</sub> emission factor, from Tables 20-2 or 20-5 (kg CO<sub>2</sub> per tonne for solid fuel, kg CO<sub>2</sub> per kilolitre for liquid fuel, or kg CO<sub>2</sub> per cubic meter for gaseous fuel)  
0.001 = Conversion factor from kilograms to tonnes.

- (b) Calculation Methodology 2. Calculate the annual CO<sub>2</sub> mass emissions using a default fuel-specific CO<sub>2</sub> emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in Equation 20-3. For use of Calculation Methodology 2 for municipal solid waste, Equation 20-3 must be used.

- (1) For any type of fuel for which an emission factor is provided in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001 \quad \text{Equation 20-2}$$

Where:

- $CO_2$  = Annual  $CO_2$  mass emissions for a specific fuel type (tonnes).  
 $n$  = Number of required heat content measurements for the year as specified in WCI.25.  
 $Fuel_p$  = Mass or volume of the fuel combusted during the measurement period  $p$  (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).  
 $HHV_p$  = High heat value of the fuel for the measurement period  $p$  (GJ per tonne for solid fuel, GJ per bone-dry tonne biomass solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).  
 $EF$  = Fuel-specific default  $CO_2$  emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg  $CO_2$ /GJ).  
0.001 = Conversion factor from kilograms to tonnes.

- (2) For units that combust municipal solid waste and produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this subpart provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-3}$$

Where:

- $CO_2$  = Annual  $CO_2$  mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).  
Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).  
 $B$  = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).  
 $EF$  = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg  $CO_2$ /GJ),<sup>1</sup> Site-specific emission factor determined through measurements may be used if updated no less often than every third year as provided in WCI.25(a)(7)(B).  
0.001 = Conversion factor from kilograms to tonnes.

- (c) Calculation Methodology 3. Calculate the annual  $CO_2$  mass emissions for each fuel by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted.

- (1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \quad \text{Equation 20-4}$$

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<sup>1</sup> The ER required development of a site-specific emission factor for MSW. For harmonization with Part 98, Subpart C, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Subpart C, Table C-1.

Where:

- $CO_2$  = Annual  $CO_2$  mass emissions from the combustion of the specific solid fuel (tonnes).  
 $n$  = Number of carbon content determinations for the year.  
 $Fuel_i$  = Mass of the solid fuel combusted in measurement period  $i$  (tonnes).  
 $CC_i$  = Carbon content of the solid fuel, from the fuel analysis results for measurement period  $i$  (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).  
3.664 = Ratio of molecular weights,  $CO_2$  to carbon.

- (2) For biomass fuels and municipal solid waste, which is combusted in units for producing steam, either use 20-5 or Equation 20-3 in WCI.23(b)(2) above. Equation 20-5 of this section may also be used for any solid biomass fuel listed in Table 20-2 provided that steam is generated by the unit.

$$CO_2 = Steam \times EF \times 0.001 \quad \text{Equation 20-5}$$

Where:

- $CO_2$  = Annual  $CO_2$  mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).  
Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).  
EF = Measured emission factor for biomass solid fuel or municipal solid waste, as applicable (kg  $CO_2$ /tonne steam), adjusted no less often than every third year.  
0.001 = Conversion factor from kilograms to tonnes.

- (3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \quad \text{Equation 20-6}$$

Where:

- $CO_2$  = Annual  $CO_2$  mass emissions from the combustion of the specific liquid fuel (tonnes).  
 $n$  = Number of required carbon content determinations for the year, as specified in WCI.25.  
 $Fuel_i$  = Volume of the liquid fuel combusted in measurement period  $i$  (kilolitres).

- CC<sub>i</sub> = Carbon content of the liquid fuel, from the fuel analysis results for measurement period *i* (tonne C per kilolitre of fuel).  
 3.664 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \times 0.001 \quad \text{Equation 20-7}$$

Where:

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from combustion of the specific gaseous fuel (tonnes).  
 n = Number of required carbon content determinations for the year, as specified in WCI.25.  
 Fuel<sub>i</sub> = Fuel combusted in period “i” (a day or month, as applicable) (volume of the gaseous fuel in Rm<sup>3</sup> at reference temperature and pressure conditions as used by the facility, or mass of the gaseous fuel in kg if a mass flow meter is used)  
 CC<sub>i</sub> = Average carbon content of the gaseous fuel, from the fuel analysis results for the period *i* (day or month, as applicable) (kg C per Rm<sup>3</sup> or kg C per kg of fuel if a mass flow meter is used).  
 3.664 = Ratio of molecular weights, CO<sub>2</sub> to carbon.  
 0.001 = Conversion factor from kg to tonnes.

(d) Calculation Methodology 4. Calculate the annual CO<sub>2</sub> mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7). This methodology requires a CO<sub>2</sub> monitor and a flow monitoring subsystem except as otherwise provided in paragraph (d)(3) of this section. CEMS shall use methodologies provided in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7) (Revised December 2005) (or by other document that supersedes it).

- (1) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO<sub>2</sub> or O<sub>2</sub> concentrations and flue gas flow measurements to determine hourly CO<sub>2</sub> mass emissions using methodologies provided in Report EPS 1/PG/7 (Revised December 2005) (or by other relevant document, if superseded).
- (2) The operator shall report CO<sub>2</sub> emissions for the reporting year in tonnes based on the sum of hourly CO<sub>2</sub> mass emissions over the year, converted to tonnes.
- (3) An oxygen (O<sub>2</sub>) concentration monitor may be used in lieu of a CO<sub>2</sub> concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO<sub>2</sub> concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO<sub>2</sub> emissions or CO<sub>2</sub> emissions from acid gas control are mixed with the combustion products) and if only the following fuels are

combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.

- (A) If the unit combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), emissions calculations shall not be based on O<sub>2</sub> concentrations.
  - (B) If the operator of a facility that combusts biomass fuels uses O<sub>2</sub> concentrations to calculate CO<sub>2</sub> concentrations, annual source testing must demonstrate that the calculated CO<sub>2</sub> concentrations, when compared to measured CO<sub>2</sub> concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).
- (4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO<sub>2</sub> mass emissions separately, as described in paragraph (f) of this section.
  - (5) For any units for which CO<sub>2</sub> emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.
  - (6) If a facility is subject to requirements for continuous monitoring of gaseous emissions, and the operator chooses to add devices to an existing CEMS for the purpose of measuring CO<sub>2</sub> concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the appropriate requirements for the facility as applicable in Canada.
  - (7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO<sub>2</sub> concentrations, the operator shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.
- (e) Use of the Four CO<sub>2</sub> Calculation Methodologies. Use of the four CO<sub>2</sub> emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:
- (1) Calculation Methodology 1 (Equations 20-1 and 20-1a).
    - (A) May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value (Table 20-1 and 20-1a) and a default CO<sub>2</sub> emission factor (Tables 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.
    - (B) May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.

- (C) May be used for a facility emitting at any level from the combustion of municipal solid waste in a unit that does not generate steam.
  - (D) May be used for the combustion of biomass listed in Table 20-2 that is exempted from verification requirements by the jurisdiction, unless it is specifically addressed under the provisions for another source category (e.g., spent pulping liquor from pulp and paper facilities).
  - (E) May not be used at a facility emitting at any level from a fuel for which you routinely perform fuel sampling and analysis for the fuel's high heat value or can obtain the results (i.e. high heat value) of fuel sampling and analysis from the fuel supplier at the minimum frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Method 2, 3 or 4 shall be used for those fuels.
- (2) Calculation Methodology 2 (Equations 20-2 and 20-3).
- (A) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements by regulation, except as specified in paragraphs (e)(2)(B) through (E) of this section. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO<sub>2</sub> emission factor for the fuel is specified in Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.
  - (B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (e)(1) of this section, Calculation Methodology 2, 3, or 4 shall be used for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.
  - (C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.
  - (D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to verification by regulation.
  - (E) Equation 20-2 may not be used for the combustion of municipal solid waste.
- (3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.
- (A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 or 4 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.

- (B) Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.
  - (C) May not be used when the use of Calculation Methodology 4 is required.
  - (D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.
  - (E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; however, it must be used for the combustion of municipal solid waste if the facility is subject to verification by regulation, unless Calculation Methodology 4 is required.
- (4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO<sub>2</sub> concentration monitor.
  - (5) You may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate fuel oil, you may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO<sub>2</sub> emissions from the combustion of all fuels shall be based solely on CEMS measurements.
- (f) CO<sub>2</sub> emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (f) to estimate biogenic CO<sub>2</sub> emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste, tires, etc.) that are partially biomass.
- (1) If CEMS are not used to measure CO<sub>2</sub> and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Calculation Methodology 1, 2, or 3, as applicable, to calculate the annual biogenic CO<sub>2</sub> mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.
  - (2) If a CEMS is used to measure CO<sub>2</sub> (or O<sub>2</sub> as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the General Provisions), use Calculation Methodology 1, 2, or 3 to calculate the annual CO<sub>2</sub> mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO<sub>2</sub> emissions determined from the CEMS-based methodology.
  - (3) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (e.g., municipal solid waste, tire-derived fuel, etc.), or if the owner or operator combusts a biomass fuel for which a CO<sub>2</sub>

emission factor is not provided in Table 20-2, use the following to estimate biogenic CO<sub>2</sub> emissions:

- (A) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO<sub>2</sub> mass emissions, as applicable.
  - (B) Determine the biogenic portion of the CO<sub>2</sub> emissions using ASTM D6866-08 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO<sub>2</sub> emissions.
  - (C) The operator shall conduct ASTM D6866-08 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08 “Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.” If municipal solid waste is combusted, the ASTM D6866-08 analysis must be performed on the exhaust gas stream.
  - (D) The operator shall divide total CO<sub>2</sub> emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.
  - (E) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.
- (4) If Equations 20-1 or 20-1a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$(Fuel)_p = \frac{[H \times S] - (HI)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}} \quad \text{Equation 20-8}$$

Where:

- (Fuel)<sub>p</sub> = Quantity of biomass consumed during the measurement period *p* (tonnes/year or tonnes/month, as applicable).
- H = Average enthalpy of the boiler steam for the measurement period (GJ/tonne).
- S = Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable).

- (HI)<sub>nb</sub> = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).
- (HHV)<sub>bio</sub> = Default or measured high heat value of the biomass fuel (GJ/tonne).
- (Eff)<sub>bio</sub> = Efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO<sub>2</sub> from sorbent.

- (1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO<sub>2</sub> emissions from the sorbent, if those CO<sub>2</sub> emissions are not monitored by CEMS:

$$CO_2 = S \times R \times \left( \frac{MW_{CO_2}}{MW_S} \right) \quad \text{Equation 20-9}$$

Where:

- CO<sub>2</sub> = CO<sub>2</sub> emitted from sorbent for the reporting year (tonnes).
- S = Limestone or other sorbent used in the reporting year, from company records (tonnes).
- R = 1.00, the calcium-to-sulphur stoichiometric ratio, or determined based on the actual absorbent used.
- MW<sub>CO<sub>2</sub></sub> = Molecular weight of carbon dioxide.
- MW<sub>S</sub> = Molecular weight of sorbent.

- (2) The annual CO<sub>2</sub> mass emissions for the unit shall be the sum of the CO<sub>2</sub> emissions from the combustion process and the CO<sub>2</sub> emissions from the sorbent.

## § WCI.24 Calculation of CH<sub>4</sub> and N<sub>2</sub>O Emissions

Calculate the annual CH<sub>4</sub> and N<sub>2</sub>O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate. You are not required to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6. However, you may use engineering estimates to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

- (a) **For fuel(s) other than coal:** If the High Heat Value (HHV) for fuels is not measured directly, use Equation 20-10 to calculate the emissions for each fuel type:

$$CH_4 \text{ or } N_2O = \sum_{i=1}^n Fuel_i \times HHV_{D,i} \times EF_i \times 0.000001 \quad \text{Equation 20-10}$$

- (a.2) **For coal:** If the emissions factors are not measured directly or provided by suppliers, use Equation 20-11 to calculate the emissions for each type of coal :

$$\text{CH}_4 \text{ or N}_2\text{O} = \sum_{i=1}^n \text{Fuel}_i \times \text{EF}_{c,i} \times 0.001$$

Equation 20-11

Where:

CH <sub>4</sub> or N <sub>2</sub> O	=	Combustion emissions from specific fuel type (tonnes CH <sub>4</sub> or N <sub>2</sub> O per year).
Fuel <sub>i</sub>	=	Mass or volume of fuel type combusted during measurement period “i” (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV <sub>D,i</sub>	=	Default high heat value specified by fuel type during measurement period “i” provided in Table 20-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF <sub>i</sub>	=	Default CH <sub>4</sub> or N <sub>2</sub> O emission factor for each fuel type during measurement period “i” provided in Tables 20-2 or 20-4, as applicable, grams CH <sub>4</sub> or N <sub>2</sub> O per GJ. The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
EF <sub>c,i</sub>	=	Default CH <sub>4</sub> or N <sub>2</sub> O emission factor for each coal type during measurement period “i” provided in Table 20-6 (grams CH <sub>4</sub> or N <sub>2</sub> O per kg of coal). The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
0.000001	=	Factor to convert grams to tonnes in Equation 20-10 .
0.001	=	Factor to convert kg to tonne in Equation 20-11.

(b) **For fuels other than coal:** If the HHVs for fuels are measured directly or provided by suppliers then use Equation 20-12 to calculate the emissions for each type of fuels:

$$\text{CH}_4 \text{ or N}_2\text{O} = \sum_{i=1}^n \text{Fuel}_i \times \text{HHV}_{P,i} \times \text{EF}_i \times 0.000001$$

Equation 20-12

(b.2) **For coal only:** If the emission factors are measured directly or provided by suppliers then use Equation 20-13 to calculate the emissions for each coal type:

$$\text{CH}_4 \text{ or N}_2\text{O} = \sum_{i=1}^n \text{Fuel}_i \times \text{EF}_{c,i} \times 0.001$$

Equation 20-13

Where:

CH <sub>4</sub> or N <sub>2</sub> O	=	Combustion emissions from specific fuel type (tonnes CH <sub>4</sub> or N <sub>2</sub> O per year).
Fuel <sub>i</sub>	=	Mass or volume of fuel type during measurement period “i” (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
HHV <sub>P,i</sub>	=	High heat value of the specific fuel during measurement period “i” measured

- directly or provided by supplier(s) (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- $EF_i$  = Default CH<sub>4</sub> or N<sub>2</sub>O emission factor for fuel “i” other than coal or during measurement period “i” provided in Tables 20-2 or 20-4, as applicable, grams CH<sub>4</sub> or N<sub>2</sub>O per GJ. The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
- $EF_{c,i}$  = CH<sub>4</sub> or N<sub>2</sub>O emission factor for each coal type during measurement “i” measured directly or provided by supplier(s) (kg CH<sub>4</sub> or N<sub>2</sub>O per tonne of coal).
- 0.000001 = Factor to convert grams to tonnes in Equation 20-12.
- 0.001 = Factor to convert kg to tonne in Equation 20-13.

- (c) For biomass and municipal solid waste combustion where Equation 20-3 or -5 or 20-4 is used to calculate CO<sub>2</sub> emissions, use Equation 20-14 of this section to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001 \quad \text{Equation 20-14}$$

Where:

- CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a biomass or municipal solid waste (tonnes).
- Steam = Total mass of steam generated by biomass or municipal solid waste combustion during the reporting year (tonnes steam).
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output (GJ/tonne steam).
- EF = Fuel-specific emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Tables 20-2, 20-4, 20-6, or 20-7 as applicable (grams per GJ).
- 0.000001 = Conversion factor from grams to tonnes.

- (d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \text{ or } N_2O = (HI)_A \times EF \times 0.000001 \quad \text{Equation 20-15}$$

Where:

- CH<sub>4</sub> or N<sub>2</sub>O = Annual CH<sub>4</sub> or N<sub>2</sub>O emissions from the combustion of a particular type of fuel (tonnes).
- (HI)<sub>A</sub> = Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information used for accounting purposes (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.). For coal cumulative mass of coal (kilograms)

from the best available information (e.g., fuel feed rate measurements, cumulative heat input, fuel heating values, engineering analysis).

EF = Fuel-specific emission factor for CH<sub>4</sub> or N<sub>2</sub>O, from Tables 20-2, 20-4, or 20-6, as applicable (grams per GJ or grams per kilogram for coal).

0.000001 = Conversion factor from grams to tonnes.

- (1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH<sub>4</sub> or N<sub>2</sub>O emissions.
  - (2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.
- (e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-10/ 20-11, 20-12/13 and 20-14 or 20-15 of this section (as applicable) to obtain the total annual CH<sub>4</sub> and N<sub>2</sub>O emissions, in tonnes.
- (f) The operator may elect to calculate CH<sub>4</sub> or N<sub>2</sub>O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of the regulator. Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.
- (g) Use of the four CH<sub>4</sub> and N<sub>2</sub>O Calculation Methodologies. Use of the four CH<sub>4</sub> and N<sub>2</sub>O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:
- (1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH<sub>4</sub> or N<sub>2</sub>O emission factor (Tables 20-2, 20-4, 20-6, and 20-7) and a default high heat value (Table 20-1 and 20-1a) is specified.
  - (2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
  - (3) WCI.24(c) may only be used for biomass or municipal solid waste combustion. WCI.24(c) must be used instead of WCI.24(a) for any unit combusting municipal solid waste that generates steam.
  - (3) (4) WCI.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO<sub>2</sub> emissions and heat input is monitored on a year round basis.

## **§ WCI.25 Sampling, Analysis, and Measurement Requirements**

- (a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the minimum frequency specified in paragraphs (a)(1) through (a)(7) of this section, subject to the requirements of WCI.23(e) and WCI.24(g). All fuel samples shall be taken at a location in the fuel handling system that provides a representative of the fuel combusted.

- (1) Once for each new fuel shipment or delivery for coal.
- (2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).
- (3) Semiannually for natural gas (when required and except as noted in WCI.025(f) and (g)).
- (4) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 20-1a (when Table 20-1a is used).
- (5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
- (6) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. If the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to  $\pm 5$  percent.
- (7) Monthly for solid fuels other than coal and waste-derived fuels (including municipal solid waste), as specified below:
  - (A) The monthly solid fuel sample shall be a composite sample of weekly samples.
  - (B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel combustion, and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
  - (C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
  - (D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
  - (E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
  - (F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.
- (8) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of WCI.25(a)(5):
  - (A) If CO<sub>2</sub> emissions are calculated using Equation 20-3 in WCI.23(b)(2) or Equation 20-4 in WCI.23(c)(1), the fuel-specific high heat value or carbon content is determined annually. If CO<sub>2</sub> emissions are calculated using Equation 20-5 in WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO<sub>2</sub>/GJ not less frequently than every third year, through a stack test measurement of CO<sub>2</sub> and use of the applicable ASME

Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

- (1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, litres, million standard cubic meters, tonnes or bone dry tonnes) using Equation 20-16. For facilities that are covered by WCI.360 (Petroleum and Natural Gas Production and Gas Processing), an operator may calculate fuel consumption for gasoline, propane and diesel using Equation 20-16 without correcting for the difference in inventory at the beginning and end of the year or using Equation 20-16a

$$\text{Fuel Consumption in the Report Year} = \text{Total Fuel Purchases} - \text{Total Fuel Sales} + \text{Amount Stored (or reading) at Beginning of Year} - \text{Amount Stored (or reading) at Year End}$$

**Equation 20-16**

$$\text{Fuel} = \sum_{j=1}^n \frac{P_{\text{rated } j}}{\eta_j} \times \frac{LD_j}{HHV_j} \times OH_j \times 0.0036$$

**Equation 20-16a**

Where:

- Fuel = Annual theoretical volume of liquid fuel combusted by fired equipment *j* (m<sup>3</sup>/year).  
 P<sub>rated j</sub> = Maximum rated power for fired equipment *j* (kW).  
 LD<sub>j</sub> = Load for fired equipment *j* (load fraction).  
 OH<sub>j</sub> = Annual operating hours for fired equipment *j* (hours/year).  
 η<sub>j</sub> = Thermal efficiency for fired equipment *j*.  
 HHV<sub>j</sub> = High heat value of the liquid fuel combusted by fired equipment *j* (GJ/m<sup>3</sup>).  
 n = quantity of fired equipment units,  
 0.0036 = conversion factor between kWh and GJ.

- (2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.
- (3) All fuel oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using calibration procedures specified by the flow meter manufacturer<sup>2</sup>. Fuel flow meters shall be recalibrated once every three years, upon replacement of a previously calibrated meter or at the minimum frequency specified by the manufacturer. For orifice, nozzle,

<sup>2</sup> California's requirements in s. 95103(k) are being considered.

and venturi flow meters, the calibration shall consist of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas. For clarity, this provision also applies to flow meters used in upstream oil and gas, and natural gas transmission and distribution applications.

- (4) For fuel oil, tank drop measurements may also be used.
- (5) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) “Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”
- (6) Facilities using Calculation Methods 1 or 2 for CO<sub>2</sub> emissions may use the following (Table 20-8) default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section. These default densities may not be used for facilities using Calculation Method 3.

**Table 20-8 Fuel Oil Default Density Values**

Fuel Oil	No.1 Oil	No.2 Oil	No.6 Oil
Default Density, kg/litre	0.81	0.86	0.97

- (c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, using an applicable analytical method listed by regulation. For fuel heat content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.
  - (1) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists. Specific test procedures that may be required to be used include ASTM D1826 “Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter”, ASTM D3588 “Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels”, or ASTM D4891-, GPA Standard 2261 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used. The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ±5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the low heat value to high heat value as follows:

$$HHV = LHV \times CF$$

**Equation 20-17**

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).  
LHV = fuel or fuel mixture low heat value (MJ/scm).  
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

- (A) By concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
  - (B) By the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.
- (2) For middle distillates and oil, or liquid waste-derived fuels, use the most appropriate method published by consensus-based standards organization. Specific test procedures that may be required to use include ASTM D240 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter” or ASTM D4809 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
  - (3) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 “Standard Test Method for Gross Calorific Value of Coal and Coke.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
  - (4) For waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 and ASTM D5468 “Standard Test Method for Gross Calorific and Ash Value of Waste Materials.” Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO<sub>2</sub> emissions using the method specified in WCI.23(f), if applicable. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
  - (5) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO<sub>2</sub> emissions.

$$(HHV)_{annual} = \frac{\sum_{p=1}^n (HHV)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-18}$$

Where:

- (HHV)<sub>annual</sub> = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- (HHV)<sub>p</sub> = High heat value of the fuel, for measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- (Fuel)<sub>p</sub> = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
- n = Number of measurement periods in the year that fuel is burned in the unit.

(d) Fuel Carbon Content Monitoring Requirements. The determination of fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, using an applicable analytical method listed by regulation. For carbon content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas .

- (1) For coal and coke, solid biomass fuels, and waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM 5373 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (2) For liquid fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,” ultimate analysis of oil or computations based on ASTM D3238, and either ASTM D2502 “Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements” or ASTM D2503 “Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (3) For gaseous fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include use ASTM D1945 “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” or ASTM D1946 “Standard Practice for Analysis of Reformed Gas by Gas Chromatography.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

- (4) Use Equation 20-19 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO<sub>2</sub> emissions.

$$(CC)_{annual} = \frac{\sum_{p=1}^n (CC)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-19}$$

Where:

- (CC)<sub>annual</sub> = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).
- (CC)<sub>p</sub> = Carbon content of the fuel, for measurement period *p* (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).
- (Fuel)<sub>p</sub> = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
- n = Number of measurement periods in the years that fuel is burned in the unit.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in WCI.23 and WCI.24 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

- (1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
- (2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in WCI.23 and WCI.24, the operator shall use the methods in WCI.26(b) to substitute for the missing values for the period of missing data.

(f) Specific Requirements for Petroleum and Natural Gas Production and Gas Processing. For field or process gas combustion or general stationary combustion of natural gas within facilities covered by WCI.360, legislative or regulatory requirements, such as those required by the Petroleum and Natural Gas Act of British Columbia are sufficient for the points of measurement that are metered. For British Columbia, combustion sources specifically covered by the Petroleum and Natural Gas Act are to be metered, sampled and analyzed in the manner prescribed by the Act and its regulations, guidelines, and policies. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. Combustion sources not

specifically covered by the legislative or regulatory requirements must be measured according to the following requirements:

- (1) For combustion emissions sources where meters are not required by legislation or regulation, a calculated shrinkage value is sufficient but must be assigned using engineering estimation techniques to the various sources, if required for reporting.
- (2) For field, pipeline quality natural gas as defined in WCI.350, or process gas combustion emissions sources where metering is not required by law or regulation and shrinkage is not calculated, engineering estimation techniques that consolidate to common meter points such as that at the input to a processing plant used for financial purposes are sufficient. As required, fuel use must be allocated (using equipment specifications, operating hours, and flow rates) to specific emissions sources.
- (3) For upstream sources, a meter is required at each installation or at a point where fuel use can be allocated to multiple combustion sources such that the aggregate of all combustion sources are metered.

All combustion estimates must be calculated in a manner that ensures that fugitive, flaring, and venting emissions as calculated under WCI.360 are uniquely reported and that no double-counting of emissions in one or more categories occurs.

Carbon content and molecular weight of the field or process gas determined annually by a facility following paragraphs (c)(1) and (d)(3) of this section for operational and regulatory purposes must be used as inputs to Equation 20-7. When this data is not available, the generic gas composition (as covered into the required format) provided in Table 360-4 (or as provided by the jurisdiction) must be used by a company or operator for the specific gas field in question.

- (g) Specific Requirements for Natural Gas Transmission and Distribution. Weights and Measures Act of Canada standards (or other appropriate standards if the Weights and Measures Act is not applicable) are deemed to be sufficiently rigorous for the sampling, analysis and measurement for the combustion of pipeline quality natural gas as defined in WCI.350 (including for derivation of standard gas composition) for facilities covered by WCI.350 – Natural Gas Transmission and Distribution. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. If a required meter is not covered by the Weights and Measures Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

## § WCI.26 Procedures for Estimating Missing Data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

- (a) For all units subject to the requirements of WCI.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content.
- (b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:
  - (1) For each missing value of the high heat value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions must be calculated, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
  - (2) For missing records of CO<sub>2</sub> concentration, stack gas flow rate, moisture percentage, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of that parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

## § WCI.27 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Consensus based standards organizations include, but are not limited to, the following: ASTM International, the American Gas Association (AGA), the American Petroleum Institute (API), the Canadian Standards Association (CSA), the Gas Processors Association (GPA), the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response

procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

Portable means designed and capable of being carried or moved from one location to another.

Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The equipment or a replacement resides at the same location for more than 12 consecutive months.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

U.S. AP-42 means the Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, U.S. EPA., as amended from time to time

§ WCI.28 Tables

**Table 20-1: Default High Heat Value by Fuel Type**

<b>Liquid Fuels</b>	<b>High Heat Value (GJ/kl)</b>
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline – Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (No. 5 & No. 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke – Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	32.41
Biodiesel (100%)	35.67
Rendered Animal Fat	34.83
Vegetable Oil	33.44
<b>Solid Fuels</b>	<b>High Heat Value (GJ/tonne)</b>
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste (at 0% moisture content) <sup>3</sup>	19.2 <sup>4</sup>
Spent Pulping Liquor (at 0% moisture content) <sup>3</sup>	13.5 <sup>4</sup>
Municipal Solid Waste	11.57
Tires	31.18
Agricultural By-products	8.6
Solid By-products	26.93
<b>Gaseous Fuels</b>	<b>High Heat Value (GJ/m<sup>3</sup>)</b>
Natural Gas	0.038
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (methane fraction)	0.0359
Biogas (methane fraction)	0.0281

<sup>1</sup> The default high heat value for “propane” is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

<sup>3</sup> HHV can be readily calculated for any moisture content as  $HHV_{dry} = HHV_{wet} / (1 - \text{percent\_moisture}/100)$ .

<sup>4</sup> A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment t.

**Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.**

Fuel Type	Default High Heat Value	Default CO <sub>2</sub> Emission Factor
Petroleum Products	GJ/kilolitre	kg CO <sub>2</sub> /GJ
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied Petroleum Gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs) <sup>1</sup>	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40
Aviation Gasoline	33.52	69.87
Kerosene-type Jet Fuel	37.66	68.40

<sup>1</sup> The default factors for “propane” are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

**Table 20-2: Default Emission Factors by Fuel Type**

	CO <sub>2</sub> Emission Factor (kg/l)	CO <sub>2</sub> Emission Factor (kg/GJ)	CH <sub>4</sub> Emission Factor (g/l)	CH <sub>4</sub> Emission Factor (g/GJ)	N <sub>2</sub> O Emission Factor (g/l)	N <sub>2</sub> O Emission Factor (g/GJ)
<b>Liquid Fuels</b>						
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267

Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline – Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (No. 5 & No. 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
<b>Biomass</b>	<b>CO<sub>2</sub> Emission Factor (kg/kg)</b>	<b>CO<sub>2</sub> Emission Factor (kg/GJ)</b>	<b>CH<sub>4</sub> Emission Factor (g/kg)</b>	<b>CH<sub>4</sub> Emission Factor (g/GJ)</b>	<b>N<sub>2</sub>O Emission Factor (g/kg)</b>	<b>N<sub>2</sub>O Emission Factor (g/GJ)</b>
Landfill Gas	2.989	54.63	0.6	1.0	0.06	0.1
Wood Waste (at 0% moisture content)	1.8 <sup>5</sup>	93.7 <sup>5</sup>	0.576	30 <sup>6</sup>	0.077	4 <sup>6</sup>
Spent Pulping Liquor (at 0% moisture content)	1.239	91.8 <sup>5</sup>	0.039	2.9 <sup>7</sup>	0.026	1.9 <sup>7</sup>
Agricultural By-products	NA	112	NA	NA	NA	NA
Solid By-products	NA	100	NA	NA	NA	NA
Biogas (captured methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA
<b>Other Solid Fuels</b>	<b>CO<sub>2</sub> Emission Factor (kg/kg)</b>	<b>CO<sub>2</sub> Emission Factor (kg/GJ)</b>	<b>CH<sub>4</sub> Emission Factor (g/kg)</b>	<b>CH<sub>4</sub> Emission Factor (g/GJ)</b>	<b>N<sub>2</sub>O Emission Factor (g/kg)</b>	<b>N<sub>2</sub>O Emission Factor (g/GJ)</b>
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A

<sup>5</sup> A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment.

<sup>6</sup> US EPA (2009). U.S. Environmental Protection Agency. *Mandatory reporting of greenhouse gases, final rule*. Washington, DC, 2009.

<sup>7</sup> IPCC (2006). Intergovernmental Panel on Climate Change. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Japan, 2006.

	CO <sub>2</sub> Emission Factor (kg/m <sup>3</sup> )	CO <sub>2</sub> Emission Factor (kg/GJ)	CH <sub>4</sub> Emission Factor (g/m <sup>3</sup> )	CH <sub>4</sub> Emission Factor (g/GJ)	N <sub>2</sub> O Emission Factor (g/m <sup>3</sup> )	N <sub>2</sub> O Emission Factor (g/GJ)
<b>Gaseous Fuels</b>						
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas – Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas – Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

<sup>1</sup> Assumes 50% moisture content of wood waste

<sup>2</sup> Assumes 12% moisture content of wood waste

**Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province**

	Marketable Gas (kg/m <sup>3</sup> )	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m <sup>3</sup> )	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

**Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas**

	CH <sub>4</sub> (g/m <sup>3</sup> )	CH <sub>4</sub> (g/GJ)	N <sub>2</sub> O (g/m <sup>3</sup> )	N <sub>2</sub> O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

**Table 20-5: Default Carbon Dioxide Emission Factors for Coal**

	Emission Factor (kg CO <sub>2</sub> /kg coal)	Emission Factor (kg CO <sub>2</sub> /GJ)
<b>Quebec</b>		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
<b>Ontario</b>		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3

- Lignite	1.48	98.7
- Anthracite	2.39	86.3
<b>Manitoba</b>		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
<b>British Columbia</b>		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

**Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal**

	<b>CH<sub>4</sub> Emission Factor (g/kg)</b>	<b>N<sub>2</sub>O Emission Factor (g/kg)</b>
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

**Table 20-7: Other Emission Factors**

	<b>CO<sub>2</sub> Emission Factor (kg/GJ)</b>	<b>CH<sub>4</sub> Emission Factor (g/GJ)</b>	<b>N<sub>2</sub>O Emission Factor (g/GJ)</b>
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO<sub>2</sub> emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

WCI has reviewed in detail results and analysis from Clarity Works on biomass emissions factors using 2010 data collected by British Columbia through the BC Reporting Regulation. Further data collection and analysis will be needed to refine the CH<sub>4</sub> and N<sub>2</sub>O emission factor for pulping liquor and hog fuel, among other fuels.

# Western Climate Initiative



Due to the timing of the release of amendments to the EPA Subpart W rule on December 2, 2011 and the potential need for the WCI to address harmonization questions with it, further consultation on WCI.350 and potential amendments to WCI.350 are scheduled to occur in 2012.

## § WCI.350 NATURAL GAS TRANSMISSION AND DISTRIBUTION

### § WCI.351 Source Category Definition

This source category consists of the following:

- (a) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines, into storage or at times directly to industrial customers or farms located along the pipeline route. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.
- (b) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.
- (c) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vapourization units for re-gasification of the liquefied natural gas.
- (d) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in Canada.
- (e) *Natural gas distribution.* Natural gas distribution consists of all natural gas equipment downstream of the station yard inlet shut-off valves of natural gas transmission pipelines at

stations where pressure reduction and/or measuring first occurs for eventual delivery of natural gas to consumers. Some natural gas distribution systems receive gas from gas batteries rather than from transmission pipelines and typically transport odourized natural gas.

- (f) *Natural gas transmission pipelines.* Natural gas transmission pipelines means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering and/or regulating stations before delivery to customers. In some cases natural gas is delivered directly from natural gas transmission pipelines to farms and industrial end users along the pipeline route.

### **§ WCI.352 Greenhouse Gas Reporting Requirements**

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (h) below, then the reported emissions for the specific source shall be reported as zero or “not applicable”.

In addition to the information required by regulation, the annual emissions data report for both each individual facility over 10,000 tonnes, and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

- (a) CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (f) of this section and from stationary and portable combustion equipment identified in paragraphs (g) and (h) of the section.

- (b) For onshore natural gas transmission compression and natural gas transmission pipelines, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:

- (1) Compressor venting (from the following sources):

- (i) Reciprocating compressors. *[WCI.353(f)]*
- (ii) Centrifugal compressors. *[WCI.353(e)]*
- (iii) Blowdown vent stacks. *[WCI.353(c)]*
- (iv) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*
- (v) Natural gas pneumatic pumps. *[WCI.353(a.1)]*
- (vi) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*
- (vii) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1)]*
- (viii) Other venting emission sources.\* *[WCI.353(l)]*

- (2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)] or [WCI.353(h)]*, size dependent

- (3) Compressor station flaring. *[WCI.353(d)]*

- (4) Compressor other fugitive emission sources.\* *[WCI.353(l)]*

- (5) Above grade meters and regulators and associated equipment at custody transfer meter-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. *[WCI.353(g)]*
  - (6) Above grade meters and regulators and associated equipment at non-custody transfer meter-regulating stations, including station equipment leaks. *[WCI.353(h)]*
  - (7) Pipeline flaring. *[WCI.353(d)]*
  - (8) Pipeline belowground meters and regulators and valve fugitives. *[WCI.353(h)]*
  - (9) Pipeline other fugitive emission sources not covered in (b)(5), (b)(6), (b)(7), (b)(8) or (b)(12) (including, but not limited to, farm taps  $\leq 700$  kPa, pipe leaks, and customer meter sets).\*, \*\* *[WCI.353(l)]*
  - (10) Pipeline other venting emission sources.\* *[WCI.353(l)]*
  - (11) Transmission storage tanks. *[WCI.353(m)]*
  - (12) Third party line hits. *[WCI.353(c.1)]*
- (c) For underground natural gas storage, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. *[WCI.353(f)]*
    - (ii) Centrifugal compressors. *[WCI.353(e)]*
    - (iii) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*
    - (iv) Natural gas pneumatic pumps. *[WCI.353(a.1)]*
    - (v) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*
    - (vi) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1)]*
    - (vii) Other venting emission sources.\* *[WCI.353(l)]*
  - (2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)]*, *[WCI.353(h)]*
  - (3) Flares. *[WCI.353(d)]*
  - (4) Other fugitive emission sources.\* *[WCI.353(l)]*
- (d) For LNG storage, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. *[WCI.353(f)]*

- (ii) Centrifugal compressors. *[WCI.353(e)]*
  - (iii) Other venting emission sources.\* *[WCI.353(l)]*
- (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*
  - (3) Flares. *[WCI.353(d)]*
  - (4) Other fugitive emission sources.\* *[WCI.353(l)]*
- (e) LNG import and export equipment, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. *[WCI.353(f)]*
    - (ii) Centrifugal compressors. *[WCI.353(e)]*
    - (iii) Blowdown vent stacks (including third party line hits). *[WCI.353(c)]*
    - (iv) Other venting emission sources.\* *[WCI.353(l)]*
  - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*
  - (3) Flares. *[WCI.353(d)]*
  - (4) Other fugitive emission sources.\* *[WCI.353(l)]*
- (f) For natural gas distribution, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Meters, regulators, and associated equipment at above grade custody transfer metering-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines. *[WCI.353(g)]*
  - (2) Meters, regulators, and associated equipment at above grade non custody transfer metering-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines. *[WCI.353(h)]*
  - (3) Equipment leaks from vaults at below grade metering-regulating stations. *[WCI.353(h)]*
  - (4) Meters, regulators, and associated equipment at above grade metering-regulating stations. *[WCI.353(h)]*
  - (5) Equipment leaks from vaults at below grade metering-regulating stations *[WCI.353(h)]*
  - (6) Pipeline main fugitive equipment leaks. *[WCI.353(h)]*

- (7) Service line fugitive equipment leaks. *[WCI.353(h)]*
- (8) Pipeline flaring. *[WCI.353(d)]*
- (9) Flares. *[WCI.353(d)]*
- (10) Third party line hits *[WCI.353(c.1)]*
- (11) Other fugitive emission sources (including, but not limited to, farm taps, and customer meter sets).\*, \*\* *[WCI.353(l)]*
- (12) Venting (from the following sources):
  - (i) Natural gas pneumatic continuous high-bleed devices. *[WCI.353(a)]*
  - (ii) Natural gas pneumatic pumps. *[WCI.353(a.1)]*
  - (iii) Natural gas pneumatic continuous low-bleed device venting. *[WCI.353(b)]*
  - (iv) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. *[WCI.353(b.1)]*
  - (v) Other venting emission sources.\* *[WCI.353(l)]*
- (g) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.
- (h) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. . The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.
- (i) Report data for each aggregated source type within paragraph (b) through (f) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):
  - (1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.
  - (2) Facility- and company-specific emission factors or emissions information, as appropriate, used in place of Tables 350-1 to 350-5.
  - (3) Count of natural gas pneumatic continuous high-bleed devices.
  - (4) Count of natural gas pneumatic continuous low-bleed devices.

- (5) Count of natural gas pneumatic intermittent (low and high) bleed devices.
- (6) Count of natural gas-driven pneumatic pumps.
- (7) Count of third party line hits
  - (i) Engineering distribution of number of line hits by volume of gas released by hit
- (8) Total pipeline length.
- (9) For each dehydrator unit report the following:
  - (i) Glycol dehydrators:
    - (A) The number of glycol dehydrators less than and greater than or equal to 11,328 Sm<sup>3</sup>/day operated
  - (ii) Desiccant dehydrators:
    - (A) The number of desiccant dehydrators operated.
- (10) For each compressor report the following:
  - (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
  - (ii) Compressor driver capacity in horsepower.
  - (iii) Number of blowdowns per year.
  - (iv) Operating mode(s) during the year (i.e., operating, not operating and pressurized or not operating and depressurized).
  - (v) Number of compressor starts per year.
- (11) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in WCI.353(g) and (h), report the following:
  - (i) Component count for each source type for which an emission factor is provided in Tables 350-1, 350-2 or 350-3, 350-4 or 350-5 in this document. Approximate counts may be used for provided for the 2011 and 2012 calendar years (reported in 2012 and 2013) in preparation for full component counts in the 2013 calendar year (reported in 2014). Current processing and instrumentation drawings (P&ID) may be used for the source of component counts for all years.
  - (ii) Total counts of leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- (12) For natural gas distribution, report the following, in addition to other requirements:
  - (i) The number of custody transfer meter-regulating stations.
  - (ii) The number of non-custody transfer meter-regulating stations.
- (13) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
  - (i) Acquired during the reporting year;
  - (ii) Sold, decommissioned, or shut-in during the reporting year;

- and,
- (iii) The greenhouse gas emissions for the facility in the previous year.
  - (iv) The purchaser or seller, as appropriate

*\* other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*\*\* tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

## **§ WCI.353 Calculation of Greenhouse Gas Emissions**

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or “not applicable”. Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 350-7.

- (a) Natural gas pneumatic continuous high-bleed device venting Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator’s pneumatic high-bleed devices (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator’s pneumatic high-bleed devices. If a transmission or distribution company has less than 25 high bleed pneumatic devices in a jurisdiction, then the method in paragraph (a)(2) may be used for all years. For the purposes of this reporting requirement, high-bleed devices are

defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m<sup>3</sup>/hr. For unmetered devices the operator must use the method specified in paragraph (a)(2).

- (1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

$$E_s = Q_j$$

**Equation 350-1**

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is metered (Sm<sup>3</sup>/y).  
 $Q_j$  = Natural gas consumption for meter  $j$  (Sm<sup>3</sup>/y).

- (2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

$$E_s = EF_j \times t_j$$

**Equation 350-2**

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered (Sm<sup>3</sup>/y).  
 $EF_j$  = Natural gas-driven pneumatic device,  $j$ , bleed rate volume as provided by the manufacturer or in Table 350-6 (Sm<sup>3</sup>/h/device).  
 $t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (3) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 350-1 for high-bleed pneumatic devices.
- (4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section
- (5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:
  - (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
  - (ii) In 2013, all continuous high-bleed natural gas pneumatic devices must be counted.

- (iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(a.1) Natural gas pneumatic pump venting. Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator’s pneumatic pumps (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator’s pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). If a transmission or distribution company has less than 25 pneumatic pumps in a jurisdiction, then the method in paragraph (a.1)(2) may be used for all years. Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.

- (1) The operator must calculate vented emissions for metered pneumatic pumps using Equation 350-1.
- (2) The operator must calculate vented emissions for unmetered pneumatic pumps using Equation 350-3.
  - (i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer “gas consumption”) per unit volume of liquid circulation rate at pump speeds and operating pressures. If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.
  - (ii) Maintain a log of the amount of liquid pumped annually from individual pumps\*.
  - (iii) Calculate the natural gas emissions for each pump using Equation 350-3.

$$E_s = EF_j \times Q_j$$

**Equation 350-3**

Where:

- $E_s$  = Annual natural gas volumetric emissions ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Natural gas-driven pneumatic pump gas emission factor expressed in “emission per volume of liquid pumped at operating pressure” as provided by the manufacturer for pump  $j$  ( $\text{Sm}^3/\text{liter}$ ).
- $Q_j$  = Volume of liquid pumped annually by pump  $j$  (liters/y).

- (3) If manufacturer data for a specific pump, or reasonably similar pump model size and operational characteristics cannot be obtained; Equation 350-2 can be used with the

population emission factor for natural gas-driven pneumatic pumps provided in Tables 350-1 or 350-2.

- (4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section
- (5) Provide the total number of natural gas pneumatic pumps as follows:
  - (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining pumps.
  - (ii) In 2013, all natural gas pneumatic pumps must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

*\* an engineering estimation approach may be used in 2012 to calculate the amount of liquid pumped annually from natural gas driven odourant injection pumps used in the distribution system, either in individual or in bulk*

- (b) Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using Equation 350-4 of this section.

$$E_s = EF_j \times t_j$$

**Equation 350-4**

Where:

- |        |   |   |
|--------|---|---|
| $E_s$  | = | Annual natural gas volumetric emissions for pneumatic continuous low-bleed bleed devices (Sm <sup>3</sup> /y).  |
| $EF_j$ | = | Population emission factor for natural gas-driven pneumatic continuous low-bleed device, $j$ , as provided in Tables 350-1 and 350-2 (Sm <sup>3</sup> /h/device). |
| $t_j$  | = | Total time that the pneumatic device, $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).                |

- (1) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (2) Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:

- (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
- (ii) In 2013, all continuous low-bleed natural gas pneumatic devices must be counted.
- (iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(b.1) Natural gas pneumatic intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.

- (1) The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta-pressure or temperature using Equation 350-5:

$$E_s = EF_j \times t_j$$

**Equation 350-5**

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Emission factor for natural gas-driven pneumatic intermittent (low and high) bleed device,  $j$ , as provided in Table 350-1 or Table 350-6 ( $\text{Sm}^3/\text{h}/\text{device}$ ).
- $t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using Equation 350-6\*:

$$E_s = EF_j \times t_j$$

**Equation 350-6**

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Emission factor for natural gas-driven pneumatic compressor starter,  $j$ , as provided by the manufacturer ( $\text{Sm}^3/\text{min}/\text{device}$ ).
- $t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

- (3) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:
  - (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
  - (ii) In 2013, all intermittent (low and high) bleed natural gas pneumatic devices must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

*\* for 2012, the volume of gas per start provided by the manufacturer may be used in place of the  $EF_j$  and  $t_j$  variables*

- (c) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases) as follows:
  - (1) Calculate the total physical volume (including, but not limited to, pipes, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.
  - (2) If the total physical volume between isolation valves is greater than or equal to 1.42 m<sup>3</sup>, retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m<sup>3</sup> are exempt from reporting under paragraph (c) of this section
  - (3) Calculate the venting emissions for each equipment system j using Equation 350-7 of this section:

$$E_s = V_v \left[ \frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)P_s} \right]$$

**Equation 350-7**

Where:

$E_s$  = Natural gas venting volumetric emissions from blowdown of equipment system (Sm<sup>3</sup>).

- $V_j$  = Total physical volume of blowdown equipment chambers (including, but not limited to, pipes, compressors and vessels) between isolation valves for the equipment system ( $m^3$ ).
- $T_s$  = Temperature at standard conditions ( $^{\circ}C$ ).
- $T_a$  = Temperature at actual conditions in the equipment system ( $^{\circ}C$ ).
- $P_s$  = Absolute pressure at standard conditions (kPaa).
- $P_{a,1}$  = Absolute pressure at actual conditions in the equipment system (kPaa) prior to depressurization.
- $P_{a,2}$  = Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPaa).

- (4) Calculate both  $CH_4$  and  $CO_2$  volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (5) Blowdowns that are directed to flares use the WCI.353(d) Flare stacks calculation method rather than WCI.353(c) Blowdown vent stacks calculation method.

(c.1) Third party line hits. Calculate emissions from third party line hits as follows:

- (1) For each dig-in incident (i.e., line hit) which results in gas release  $\geq 1.416 \text{ Sm}^3$ , calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below<sup>1</sup>. For 2012, the methodology referenced in paragraph (iv) may be used in addition to those in paragraphs (i) and (ii).
- (i) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

$$Q_s = \frac{3.6 \times 10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

**Equation 350-8**

Where:

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<sup>1</sup> Methodology Manual, Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

$$M = \sqrt{\frac{2 \left[ \left( \frac{P_a}{P_e} \right)^{\frac{K-1}{K}} - 1 \right]}{K-1}}, \text{ (for } M \leq 1),$$

**Equation 350-9**

$M = 1$ , (for all other cases)

Where:

- $Q_s$  = natural gas venting volumetric flow rate ( $\text{Sm}^3/\text{h}$ )
- $A$  = cross-sectional flow area of the pipe ( $\text{m}^2$ ,  $A = \pi D^2/4000$ )
- $D$  = inside diameter of the pipe (mm)
- $K$  = specific heat ratio of the gas (dimensionless – 1.299 for methane)
- $M$  = Mach number of the flow (m/s)
- $MW$  = molecular weight of the gas (kg/mole, 16.043 kg/mole for methane)
- $P_e$  = pressure at the damage point (local atmospheric pressure, kPaa)
- $P_a$  = pressure inside the pipe at supply (kPaa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
- $R$  = universal gas constant ( $8.3145 \text{ kPam}^3/\text{kmol/K}$ )
- $T_a$  = temperature inside pipe at the supply ( $^{\circ}\text{C}$ )
- $\rho_s$  = gas density at standard conditions ( $\text{kg/m}^3$ ) ( $0.6785 \text{ kg/m}^3$  for  $\text{CH}_4$ )

(ii) For pipeline punctures use the following methodology (for flows not choked):

$$Q_s = \frac{A_e}{\rho_s} \sqrt{\frac{2000 \cdot K}{K-1} P_a \rho_a \left[ \left( \frac{P_{Atm}}{P_a} \right)^{2/K} - \left( \frac{P_{Atm}}{P_a} \right)^{(K+1)/K} \right]}$$

**Equation 350-10**

Where:

$$\left( \frac{P_{Atm}}{P_a} \right) \geq \left( \frac{P_{Atm}}{P_a} \right)_{choked} = \left( \frac{2}{K+1} \right)^{K/(K-1)} = 0.546 \quad \text{(for methane)}$$

**Equation 350-11**

Where:

- $A_e$  = size of the hole in the pipe ( $\text{m}^2$ )
- $P_a$  = pressure inside the pipe at the puncture location (kPaa)
- $\rho_a$  = gas density inside the pipe at the puncture location ( $\text{kg/m}^3$ )
- $MW$  = molecular weight of the natural gas (16.043 for methane)
- $T_a$  = temperature inside the pipe ( $^{\circ}\text{C}$ )
- $(P_{ATM}/P_a)_c$  = 0.546 - lower limit for choked flow

- (iii) Check for choked flow
  - (A) If  $(P_{ATM}/P_a)$  is  $\geq 0.546$  flow is not choked and the reporter must use the equations in section (c.1)(ii) above.
  - (B) If  $(P_{ATM}/P_a) < 0.546$  flow is choked and A must be set to the cross sectional flow area of the pipe and the reporter must use the equations in section (c.1)(i) above.
- (iv) For 2012 calendar year emissions, an operator may use other methods to calculate emissions published in the CEPEI Methodology Manual, or other industry standard reference sources.
- (v) Calculate volumetric natural gas emissions by multiplying  $Q_s$  for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.
- (vi) Calculate GHG ( $CH_4$  and  $CO_2$  emissions) mass emissions using the methodologies in sections (j) and (j) of this section.

(d) Flare stacks. Calculate  $CO_2$ ,  $CH_4$ , and  $N_2O$  emissions from a flare stack as follows:

- (1) If there is a continuous flow measurement device on the flare, measured flow volumes can be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or use engineering calculations based on process knowledge, company records, and best available data.
- (2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, use the gas compositions for each stream of hydrocarbons going to the flare (must be determined using (j)(1) and (j)(2) of this section).
- (3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.
- (4) Calculate GHG volumetric emissions at actual conditions using Equations 350-12, 350-13, 350-14, and 350-15 of this section.

$$E_{s,CH_4}(noncombusted) = Q_s \times (1 - \eta) \times Y_{CH_4} \quad \text{Equation 350-12}$$

$$E_{s,CO_2}(noncombusted) = Q_s \times Y_{CO_2} \quad \text{Equation 350-13}$$

$$E_{s,CO_2}(combusted) = \sum_i \eta \times Q_s \times Y_i \times n_i \quad \text{Equation 350-14}$$

$$E_{s,CO_2}(total) = E_{s,CO_2}(combusted) + E_{s,CO_2}(noncombusted) \quad \text{Equation 350-15}$$

Where:

$E_{s,CH_4}$ (noncombusted)	=	Contribution of annual noncombusted volumetric CH <sub>4</sub> emissions from flare stack (Sm <sup>3</sup> ).
$E_{s,CO_2}$ (noncombusted)	=	Contribution of annual volumetric CO <sub>2</sub> emissions from CO <sub>2</sub> in the inlet gas passing through the flare noncombusted (Sm <sup>3</sup> ).
$E_{s,CO_2}$ (combusted)	=	Contribution of annual volumetric CO <sub>2</sub> emissions from combustion from flare stack (Sm <sup>3</sup> ).
$Q_s$	=	Volume of natural gas sent to flare during the year (Sm <sup>3</sup> ).
$\eta$	=	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, $\eta$ is zero.
$Y_{CH_4}$	=	Mole fraction of CH <sub>4</sub> in gas to the flare.
$Y_{CO_2}$	=	Mole fraction of CO <sub>2</sub> in gas to the flare.
$Y_i$	=	Mole fraction of hydrocarbon constituents $i$ (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
$n_i$	=	Number of carbon atoms in the hydrocarbon constituent $i$ ; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

- (5) Calculate both CH<sub>4</sub> and CO<sub>2</sub> mass emissions from volumetric CH<sub>4</sub> and CO<sub>2</sub> emissions using the calculation in paragraph (k) of this section.
- (6) Calculate N<sub>2</sub>O emissions using Equation 350-16.

$$E_{N_2O} = Q_s \times HHV \times EF \times 0.001$$

**Equation 350-16**

Where:

$E_{N_2O}$	=	Annual N <sub>2</sub> O mass emissions from flaring (tonnes/y).
$Q_s$	=	Volume of gas combusted by the flare in the reporting period (Sm <sup>3</sup> /y).
$HHV$	=	High heat value of the flared gas from paragraph (d)(2)
$EF$	=	N <sub>2</sub> O emission factor. Use $9.52 \times 10^{-5}$ kg N <sub>2</sub> O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in this section. Where gas to be flared is manifolded from multiple sources in WCI.353 to a common flare, report all flaring emissions under WCI.353(d).

(e) Centrifugal compressor venting. Calculate emissions from centrifugal compressor vents as follows.

- (1) The operator must calculate CO<sub>2</sub>, and CH<sub>4</sub>, and N<sub>2</sub>O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) for all compressors using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.354(b).
- (2) Estimate annual emissions using flow meter measurement using Equation 350-17 of this section.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_{i,m} \times (1 - CF)$$

**Equation 350-17**

Where:

- $E_{s,i}$  = Annual GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>) volumetric emissions from all measured compressor venting modes (Sm<sup>3</sup>).
- $Q_{s,m}$  = Measured volumetric gas emissions during operating mode  $m$  described in paragraph (e)(4) of this section (Sm<sup>3</sup>/h).
- $t_m$  = Total time the compressor is in operating mode  $m$  during the calendar year (h)
- $Y_i$  = Mole fraction of GHG  $i$  in the degassing vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.
- CF = Fraction of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) unit isolation-valve vents and blowdown-valve vents.
  - (i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.
  - (ii) Operating mode.
  - (iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.
    - (A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not

required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

- (5) Calculate both CH<sub>4</sub> and CO<sub>2</sub> mass emissions from volumetric emissions using calculations in paragraph (k) of this section.
  - (6) Calculate emissions from degassing vent vapours to flares as follows:
    - (i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (e)(1) through (3) of this section.
    - (ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine degassing vent vapour emissions from the flare.
  - (7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented lines must use methods outlined in EPA Subpart W 98.233(o)
- (f) Reciprocating compressor venting. Calculate annual CH<sub>4</sub> and CO<sub>2</sub> emissions from all reciprocating compressor vents as follows. Where venting emissions are sent to a common flare, calculate emissions using WCI.353(d).
- (1) Estimate annual emissions using the flow measurement in (f)(2) or (f)(3) below and Equation 350-18.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

**Equation 350-18**

Where:

- |           |   |   |
|-----------|---|---|
| $E_{s,i}$ | = | Annual volumetric emissions of GHG $i$ (either CH <sub>4</sub> or CO <sub>2</sub> ) from all measured compressor venting modes (Sm <sup>3</sup> /y).  |
| $Q_{s,m}$ | = | Measured volumetric gas emissions during operating mode $m$ described in paragraph (f)(4) (Sm <sup>3</sup> /h)..  |
| $t_m$     | = | Total time the compressor is in operating mode $m$ during the calendar year (h).  |
| $Y_i$     | = | Mole fraction of GHG $i$ in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.   |
| CF        | = | Fraction of reciprocating compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting. |

- (2) If the reciprocating rod packing and blowdown vent is connected to an open-ended vent line then use one of the following two methods to calculate emissions.

- (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or High-flow Sampler according to methods set forth in WCI.354(c) and (d).
  - (ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.354(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open-ended vents, such as unit isolation valves on not-operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.354(a).
- (3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:
- (i) Use the methods described in WCI.354(a) to conduct a progressive leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
  - (ii) Measure emissions using a High-flow Sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.354(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents.
- (i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.
  - (ii) Operating mode, reciprocating rod-packing emissions.
  - (iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.
- (A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode
- (5) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.
- (6) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

- (i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.
- (ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year .

(g) Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in WCI.354(a)(0.1)) or progressive sampling methods (described in WCI.354(a)(0.2)) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in WCI.352(b)(2) (where total emissions for a compressor station are 10,000 tonnes CO<sub>2</sub>e or greater), (b)(5), (c)(2), (d)(2), (e)(2), and (f)(1). This paragraph (g) applies to emissions sources in streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight need to be reported instead under paragraph (l) of this section. \*\*

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using Equation 350-19 (for volumetric emission factor [Sm<sup>3</sup>/h/component]) or Equation 350-20 (for mass emission factors [t/h/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

$$E_i = EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

**Equation 350-19**

$$E_{s,i} = EF_s \times Y_i \times t$$

**Equation 350-20**

Where:

- $E_{s,i}$  = Annual total mass emissions of GHG  $i$  (CH<sub>4</sub> or CO<sub>2</sub>) from each fugitive equipment leak source (tonnes/year).
- $EF_s$  = Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section or facility/company-specific emission factors\* used in place of Tables 350-1 to 350-5 (Sm<sup>3</sup>/component/year for Equation 350-19 and tonnes/ component/year for Equation 350-20).
- $Y_i$  = For volumetric emissions in Equation 350-19, use 1 for CH<sub>4</sub> and  $1.1 \times 10^{-2}$  for CO<sub>2</sub>. For mass emissions in Equation 350-20, use mass fractions of CH<sub>4</sub> and CO<sub>2</sub> from each unit of a distribution or transmission company within a

		jurisdiction that has similar gas composition or the 2007 Canadian Energy Partnership for Environmental Innovation (CEPEI) Methodology Manual. <sup>2</sup>
t	=	Total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the last survey during which it was determined to be not leaking, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.
$\rho_{s,i}$	=	Density of GHG <i>i</i> (1.861 kg/m <sup>3</sup> for CO <sub>2</sub> and 0.678 kg/m <sup>3</sup> for CH <sub>4</sub> at standard conditions of 15 °C and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

- (1) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.
- (2) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open-ended lines.
- (3) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive equipment leaks detected from valves, pump seals, connectors, and other equipment.
- (4) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.
- (5) Natural gas distribution facilities for above ground meters and regulators at custody transfer meter-regulating stations shall use the appropriate default leaker emission factors listed in Table 350-5 of this section for fugitive equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

*\* component-specific emission factors may equal leak rates quantified, following WCI.354(c) or (d), during leak detection surveys.*

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<sup>2</sup> Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007

*\*\* tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

- (h) Population count and emission factors. This paragraph applies to emissions sources listed in WCI.352 (b)(2) (where total emissions for a compressor station are less than 10,000 tonnes CO<sub>2</sub>e), b(6), b(8), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4), (f)(5), (f)(6) and (f)(7) on streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight do not need to be reported. \*\*

Calculate emissions from all sources listed in this paragraph using Equation 350-21 (for volumetric emission factor [m<sup>3</sup>/h/component]) or Equation 350-22 (for mass emission factors [kg/h/component]) of this section, as appropriate.

$$E_i = N \times EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

**Equation 350-21**

$$E_i = N \times EF_s \times X_i \times t \times 0.001$$

**Equation 350-22**

Where:

- $E_i$  = Annual total mass emissions of GHG  $i$  (CH<sub>4</sub> or CO<sub>2</sub>) from each fugitive source (tonnes/year).
- $E_{s,i}$  = Annual total volumetric emissions of GHG  $i$  (CH<sub>4</sub> or CO<sub>2</sub>) from each fugitive source (Sm<sup>3</sup>/year).
- $N$  = Total number of this type of emission source at the facility. Per WCI.352(i)(11), average component counts by major equipment pieces from the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual (or other relevant Canadian Gas Association and/or Canadian Association of Petroleum Producers documentation) may be used for 2011 and 2012 calendar year emissions as appropriate for operations and required by (h)(1) through (h)(4), below. For 2013 calendar year emissions and onwards component counts for individual facilities must be used. If facility or company-specific major equipment count data that meet or exceed the quality of the relevant CGA default count data are available, they must be used in its place. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years.

$EF_s$	=	Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section ( $\text{Sm}^3/\text{component}/\text{hour}$ for Equation 350-21 and tonnes/component/hour for Equation 350-22). EF for custody transfer meter-regulating stations is determined in Equation 350-23. Direction on the use of Tables 350-1 through 350-5, provided prior to the tables, must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used*.
$Y_i$	=	For volumetric emissions in Equation 350-21, use 1 for $\text{CH}_4$ and $1.1 \times 10^{-2}$ for $\text{CO}_2$ .
$X_i$	=	For mass emissions in Equation 350-22, use mass fractions of $\text{CH}_4$ and $\text{CO}_2$ from operation/facility-specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual.
$t$	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year ( hours).
$P_{s,i}$	=	Density of GHG $i$ ( $1.861 \text{ kg}/\text{m}^3$ for $\text{CO}_2$ and $0.678 \text{ kg}/\text{m}^3$ for $\text{CH}_4$ at standard conditions of $15^\circ\text{C}$ and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

- (1) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open-ended lines.
- (2) LNG storage facilities shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive equipment leaks from vapour recovery compressors.
- (3) LNG import and export facilities shall use the appropriate default population emission factor listed in Table 350-4 of this section for fugitive equipment leaks from vapour recovery compressors.
- (4) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (h)(4) of this section.
  - (i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table 350-5 of this section.
  - (ii) Above grade meters and regulators at meter-regulating stations not at custody transfer as listed WCI.352(f)2), must use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (g)(5) of this section to develop facility emission factors using Equation 350-23 of this section. The calculated facility emission factor from Equation 350-23 of this section shall be used in Equations 350-15 and 350-16 of this section.

$$EF_{s,i} = \sum \frac{E_{s,i}}{N \times 8760} \quad \text{Equation 350-23}$$

Where:

- $EF_{s,i}$  = Facility emission factor for a meter/regulator run at above grade metering-regulating for GHG<sub>i</sub> (Sm<sup>3</sup>/year).
- $E_{s,i}$  = Annual volumetric GHG emissions, CO<sub>2</sub> or CH<sub>4</sub> from all equipment leak sources at all above-grade, custody-transfer, metering-regulating stations, from paragraph (g) of this section (Sm<sup>3</sup>).
- $N$  = Total number of meter/regulator runs at all custody-transfer, metering-regulating stations.
- 8760 = Conversion to hourly emissions

- (iii) To ensure proper calculation of emissions from buried pipeline-main and service line equipment leaks, Equations 350-21 and 350-22 and their inputs may be modified as necessary to meet 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual standards. For example, the length of the installed underground pipeline used in place of count and company-specific leak data and CEPEI manual equations is permitted.

*\* facility -specific emission factors may equal leak rates quantified, following WCI.354(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of WCI.357 – Directions for the use of Tables 350-1 to 350-5.*

*\*\* tubing systems less than one half inch diameter may be quantified using WCI.353(g) instead of WCI.353(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.353(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

- (i) **Volumetric emissions.** Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) , with actual pressure and temperature of this section determined by engineering estimate based on best available data unless otherwise specified.
- (1) Calculate natural gas volumetric emissions at standard conditions by converting actual temperature and pressure to standard temperature and pressure (15 °C and 1 atmosphere in Canada) using Equation 350-24 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

**Equation 350-24**

Where:

- $E_s$  = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (Sm<sup>3</sup>).

- $E_a$  = Natural gas volumetric emissions at actual conditions ( $m^3$ ).  
 $T_s$  = Temperature at standard conditions ( $^{\circ}C$ ).  
 $T_a$  = Temperature at actual emission conditions ( $^{\circ}C$ ).  $P_s$  = Absolute pressure at standard conditions (kPa).  
 $P_a$  = Absolute pressure at actual conditions (kPa).

- (2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-25 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

**Equation 350-25**

Where:

- $E_{s,i}$  = GHG  $i$  volumetric emissions at standard temperature and pressure (STP) conditions ( $Sm^3$ ).  
 $E_{a,i}$  = GHG  $i$  volumetric emissions at actual conditions ( $m^3$ ).  
 $T_s$  = Temperature at standard conditions. ( $^{\circ}C$ ).  
 $T_a$  = Temperature at actual emission conditions. ( $^{\circ}C$ ).  
 $P_s$  = Absolute pressure at standard conditions (kPa).  
 $P_a$  = Absolute pressure at actual conditions (kPa).

- (j) GHG volumetric emissions. If the GHG volumetric emissions at actual conditions are known, follow the method in (j)(2) to calculate their emissions at standard conditions. If the GHG volumetric emissions are not yet known, then follow the methods below to calculate GHG volumetric emissions at standard conditions as specified in paragraphs (j)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

- (1) Estimate  $CH_4$  and  $CO_2$  emissions from natural gas emissions using Equation 350-26 of this section.

$$E_{s,i} = E_s \times Y_i$$

**Equation 350-26**

Where:

- $E_{s,i}$  = GHG  $i$  (either  $CH_4$  or  $CO_2$ ) volumetric emissions at standard conditions.  
 $E_s$  = Natural gas volumetric emissions at standard conditions.  
 $Y_i$  = Mole fraction of GHG  $i$  in the natural gas.

- (2) For Equation 350-26 of this section, the mole fraction,  $Y_i$ , shall be the annual average mole fraction for each unit of a natural gas distribution, natural gas transmission, LNG storage, LNG import or export, or underground natural gas storage company within a jurisdiction that has similar gas composition as sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in WCI.354(b), and specified in paragraphs (j)(2)(i) through (v) of this section.
- (i) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.
  - (ii) GHG mole fraction in natural gas stored in underground natural gas storage facilities.
  - (iii) GHG mole fraction in natural gas stored in LNG storage facilities.
  - (iv) GHG mole fraction in natural gas stored in LNG import and export facilities.
  - (v) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

- (k) GHG mass emissions. Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 350-27 of this section.

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

**Equation 350-27**

Where:

- $E_i$  = GHG  $i$  (either CH<sub>4</sub>, CO<sub>2</sub>, or N<sub>2</sub>O) mass emissions (tonnes CO<sub>2</sub>e).  
 $E_{s,i}$  = GHG  $i$  (either CH<sub>4</sub>, CO<sub>2</sub> or N<sub>2</sub>O) volumetric emissions (Sm<sup>3</sup>).  
 $\rho_{s,i}$  = Density of GHG  $i$  (1.861 kg/m<sup>3</sup> for CO<sub>2</sub> and 0.678 kg/m<sup>3</sup> for CH<sub>4</sub> at standard conditions of  $T_s = 15^\circ\text{C}$  and  $P_s = 101.325 \text{ kPa}$ ).

$$= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

- $GWP_i$  = Global warming potential of GHG  $i$ , (1 for CO<sub>2</sub> and 21 for CH<sub>4</sub>, and 310 for N<sub>2</sub>O).  
 $MW_i$  = Molecular weight for GHG <sub>$i$</sub>  taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).  
 $R_u$  = Universal gas constant (8.31434 kJ/kmole K)  
0.001 = Conversion factor from kilograms to tonnes.

- (l) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.353 must be calculated by methodologies consistent with

those presented here, in the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual<sup>3</sup> (as amended from time to time), or in other relevant Canadian Gas Association documentation.

- (m) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in onshore natural gas transmission compression facilities calculate CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) annual emissions from compressor scrubber dump valve leakage as follows. For 2012, other methodologies may be used to quantify emissions from transmission storage tanks in addition to those outlined below.
- (1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in WCI.354(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in WCI.354(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in WCI.354(a)(4).
  - (2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (m)(2) of this section to quantify annual emissions:
    - (i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in WCI.354(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (m)(1) of this section to detect continuous leakage, this serves as the measurement.
    - (ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in WCI.354(a)(4).
    - (iii) Use the appropriate gas composition in paragraph (j) of this section.
  - (3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.
  - (4) Calculate annual emissions from storage tanks to flares as follows:
    - (i) Use the storage tank emissions volume and gas composition as determined in paragraphs (m)(1) through (m)(3) of this section.
    - (ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine storage tank emissions sent to a flare.

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<sup>3</sup> Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007.

## § WCI.354 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

### (a) Leak Detection

- (0.1) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or similar standard Canadian Gas Association methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein. A minimum of 12 months and a maximum of 36 months is allowed between surveys.
- (0.2) If there is no such legal requirement (as specified in paragraph (a)(0.1) of this section), then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.353(f), (g), and (h), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based on random or spot-sampling, modeling, detection or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak is found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode.

- (1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:
- (i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument inspection described in the relevant best practices. The

detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

- (ii) Provide a date and time stamp for video records of every monitoring event.
- (2) Bubble tests.
  - (3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions
  - (4) Other methods as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary for operational circumstances provided that sufficient documentation as to the method used, results on tests, and the methods reliability and accuracy is maintained and updated at regular intervals.
- (b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to the an appropriate standard published by a consensus standards organization such as Canadian Standards Association (CSA), Canadian Gas Association, Canadian Energy Pipeline Association (CEPA), ASTM International, American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), American Petroleum Institute (API) may be used. If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.
- (c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed 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. If the bag inflates in less than one second, assume one second inflation time.
  - (2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

- (3) Correct the natural gas volumetric emissions to standard conditions using the calculations in WCI.353(i).
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).
- (d) Use a High-flow Sampler to measure emissions within the capacity of the instrument.
- (1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH<sub>4</sub> by using calibrated gas samples and by following manufacturer's instructions for calibration.
  - (2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
  - (3) If the High-flow 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.
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).

### **§ WCI.355 Procedures for Estimating Missing Data**

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

### **§ WCI.356 Definitions**

Blowdown vent stack emissions mean natural gas and/or CO<sub>2</sub> released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO<sub>2</sub> by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO<sub>2</sub> from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO<sub>2</sub> 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 seal degassing venting emissions mean emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO<sub>2</sub>. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means 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.

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody-transfer means the transfer of product from one gas company to another gas company, excluding transfers between companies who have same parent company.

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

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Farm taps mean pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare, for the purposes of WCI.350, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

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

High-bleed pneumatic devices means automated continuous bleed control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour.

Intermittent-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

Meter-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

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.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.3 MJ/m<sup>3</sup> or less than 40.98 MJ/m<sup>3</sup>, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

Portable means the same as defined in WCI.361(a)(2), as applicable to natural gas transmission and distribution operations

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

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 emissions means hydrocarbon 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 gas stream 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 the compressed gas stream that escapes to the atmosphere.

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

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

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.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scrapper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

Vapour 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.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

## § WCI.357 Tables

### Directions for the use of Tables 350-1 to 350-5

- (a) Starting with 2014 calendar year emissions, for each component listed in the Tables 350-1 to 350-5, or otherwise required by the quantification method referencing Tables 350-1 and 350-2:
- (1) If statistically valid facility-specific emission factors for a component type are available or can be safely or reasonably developed they must be used
  - (2) If facility-specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors if they can be safely or reasonably developed.
  - (3) If statistically valid facility or company-specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 350-1 to 350-5 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as some booster stations used only sporadically during a year) may continue to use the default tables.
- (b) For 2011, 2012 and 2013 calendar year emissions,
- (1) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 350-1 to 350-5 are used, an explanation as to why company or facility-specific emission factors cannot be used must be provided to the jurisdiction.
- (c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place
- (d) Any changes from facility-specific factors to company-specific or table factors, or from company-specific factors to the defaults in Tables 350-1 to 350-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question
- (e) If an emission factor required by the quantification method referencing Tables 350-1 through 350-5 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 or the 2007 Canadian Gas Association Methodology Manual may be used (as converted for use in the relevant equation).
- (f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request
- (g) All emission factors or data collection for emission factors must be developed using Canadian Gas Association (CGA) standard methods, or other methods if CGA methods are not available or applicable. Facility and company-specific emission factors must be updated

at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

- (h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.
- (i) The default emission factors provided in Tables 350-1 to 350-5 below are industry average emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

**TABLE 350-1 –DEFAULT EMISSION FACTORS FOR TRANSMISSION**

Transmission	Emission Factor (tonnes/hour/component) Direct conversion of EF's in CGA Manual <sup>4</sup> Table 9 (kg to tonnes)
<b>Leaker Emission Factors - All Components, Gas Service</b>	
Connector	4.848E-5
Block valve	1.275E-4
Control valve	8.205E-5
Compressor blowdown valve	5.691E-3
Pressure relief valve	5.177E-4
Orifice meter	2.076E-4
Other meter	3.493E-7
Regulator	1.125E-4
Open-ended line	1.580E-4
<b>Population Emission Factors - Other Components, Gas Service</b>	
	<b>Emission Factor (Sm<sup>3</sup>/hour/component) Direct conversion of EF's in EPA Subpart W Tables W1-A and W-3 (scf to Sm<sup>3</sup>)</b>
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 E-1
Pneumatic Pumps	3.766 E-1

\* The distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

<sup>4</sup> Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here as well as permit use of the most recent values published.

**TABLE 350-2 –DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE\***

Underground Storage	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-4 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - Storage Station, Gas Service</b>	
Valve <sup>1</sup>	4.268 E-1
Connector	1.60 E-1
Open-ended line	4.967 E-1
Pressure relief valve	1.140
Meter	5.560 E-1
<b>Population Emission Factors - Storage Wellheads, Gas Service</b>	
Connector	2.8 E-4
Valve	2.8 E-3
Pressure relief valve	4.8 E-3
Open-ended line	8.5 E-4
<b>Population Emission Factors - Other Components, Gas Service</b>	
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 E-1

\*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-4.

<sup>1</sup> Valves include control valves, block valves and regulator valves

**TABLE 350-3 –DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE\***

LNG Storage	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - LNG Storage Components, LNG Service</b>	
Valve	3.43 E-2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other <sup>1</sup>	5.10 E-2
<b>Population Emission Factors - LNG Storage Compressor, Gas Service</b>	
Vapour Recovery Compressor	1.20 E-1

<sup>1</sup> The “other” equipment type should be applied for any equipment type other than connectors, pumps, or valves.

\* Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-5.

**TABLE 350-4–DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS\***

LNG Terminals	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - LNG Terminals Components, LNG Service</b>	
Valve	3.43 E -2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other	5.10 E-2
<b>Population Emission Factors - LNG Terminals Compressor, Gas Service</b>	
Vapour recovery compressor	1.20 E-1

\*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-6.

**TABLE 350-5 –DEFAULT EMISSION FACTORS FOR DISTRIBUTION**

Distribution	Emission Factor** (tonnes/hour/component) Direct conversion of EF's in CGA Manual <sup>5</sup> Table 9 (kg to tonnes)
<b>Leaker Emission Factors - Above Grade M&amp;R Stations Components, Gas Service</b>	
Connector	0.6875 E-3
Block valve	1.410 E-2
Control valve	7.881 E-2
Pressure relief valve	3.524 E-2
Orifice meter	8.091 E-3
Regulator	2.849 E-2
Open-ended line	1.216 E-1
<b>Population Emission Factors - Below Grade M&amp;R Stations Components, Gas Service<sup>1</sup></b>	
Below grade M&R station, inlet pressure > 300 psig	3.74 E-2
Below grade M&R station, inlet pressure 100 to 300 psig	5.7 E-3
Below grade M&R station, inlet pressure < 100 psig	2.8 E-3

<sup>5</sup> Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

	<b>Emission Factor (Sm<sup>3</sup>/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-3 to 6 (scf to Sm<sup>3</sup>) except where noted</b>
<b>Population Emission Factors - Distribution Mains, Gas Service<sup>2*</sup></b>	
Unprotected steel	1.83 E-1
Protected steel	7.22 E-2
Plastic	7.76 E-2
Cast iron <sup>*</sup>	7.836 E-1
	<b>Emission Factor (Sm<sup>3</sup>/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-7 to 10 (scf to Sm<sup>3</sup>) except where noted</b>
<b>Population Emission Factors - Distribution Services, Gas Service<sup>*</sup></b>	
Unprotected steel	7.08 E-2
Protected steel	3.23 E-2
Plastic	1.04 E-2
Copper	2.7 E-2

<sup>1</sup> Emission Factor is in units of “Sm<sup>3</sup>/hour/station”

<sup>2</sup> Emission Factor is in units of “Sm<sup>3</sup>/hour/service”

\*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-7.

\*\* the distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

**Table 350-6. Average manufacturer bleed rates for pneumatic controllers, positioner, transmitters and transducers.**

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m <sup>3</sup> /h) <sup>4</sup>
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m <sup>3</sup> /h) <sup>4</sup>
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:

<sup>1</sup> Canadian Association of Petroleum Producers. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.

<sup>2</sup> United States Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Washington, DC. 2006. Appendix A converted to metric units.

<sup>3</sup> Various manufacturer specification publications.

<sup>4</sup> Factors equal to zero indicate that the device does not vent gas.

**Table 350-7. Nomenclature (subscripts, variables and their descriptions)**

<b>Variable Name</b>	<b>Description</b>
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance.
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 °C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
$\rho$	Variable - density
$\eta$	Variable – efficiency (fractional)

# Western Climate Initiative



Due to the timing of the release of amendments to the EPA Subpart W rule on December 2, 2011 and the potential need for the WCI to address harmonization questions with it, further consultation on WCI.360 and potential amendments to WCI.360 are scheduled to occur in 2012.

## §WCI.360 PETROLEUM AND NATURAL GAS PRODUCTION AND GAS PROCESSING

### § WCI.361 Source Category Definition

(a) This source category consists of the following:

- (1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.
- (2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using CO<sub>2</sub>, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.
- (3) *Onshore natural gas processing.* Natural gas processing plants separates and/or recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, separation of natural gas liquids, sulphur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO<sub>2</sub>

separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants may be considered a part of the processing plant if emissions are not calculated under onshore petroleum and natural gas production. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within onshore natural gas processing for the purposes of emissions calculation. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

- (b) This source category does not include natural gas transmission and distribution (i.e., onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, and natural gas distribution). These are included in WCI.350 (Natural Gas Transmission and Distribution).

### **§ WCI.362 Greenhouse Gas Reporting Requirements**

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (f), below then the reported emissions for the specific source shall be reported as zero or “not applicable”.

In addition to the information required by regulation, the annual emissions data report, for both each individual facility over 10,000 tonnes and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

- (a) CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (d) of this section and from stationary and portable combustion equipment identified in paragraphs (e) and (f) of the section.
- (b) For offshore petroleum and natural gas production, report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions. *[WCI.363(p), reserved]*
- (c) For onshore petroleum and natural gas production, report CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions from the following source types:
- (1) Natural gas pneumatic continuous high-bleed device venting. *[WCI.363(a)]*
  - (2) Natural gas-driven pneumatic pump venting. *[WCI.363(a.1)]*
  - (3) Natural gas pneumatic continuous low-bleed device venting. *[WCI.363(b)]*
  - (4) Natural gas pneumatic intermittent (low and high) bleed device venting. *[WCI.363(b.1)]*

- (5) Acid gas removal venting or incineration process. *[WCI.363(c)]*
  - (6) Dehydrator vents. *[WCI.363(d)]*
  - (7) Well venting for liquids unloading. *[WCI.363(e)]*
  - (8) Gas well venting during well completions or workovers. *[WCI.363(f)]*
  - (9) Blowdown vent stacks. *[WCI.363(g)]*
  - (10) Third party line hits. *[WCI.363(g.1)]*
  - (11) Onshore production and processing storage tanks. *[WCI.363(h)]*
  - (12) Transmission storage tanks *[WCI.363(h.1)]*
  - (13) Well testing venting and flaring. *[WCI.363(i)]*
  - (14) Associated gas venting and flaring. *[WCI.363(j)]*
  - (15) Flare stacks. *[WCI.363(k)]*
  - (16) Centrifugal compressor venting. *[WCI.363(l)]*
  - (17) Reciprocating compressor venting. *[WCI.363(m)]*
  - (18) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*
  - (19) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other fugitive equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps). *[WCI.363(o)]*
  - (20) EOR injection pump blowdown. *[WCI.363(t)]*
  - (21) Hydrocarbon liquids dissolved CO<sub>2</sub> from flashing [Reserved]. *[WCI.363(u)]*
  - (22) Produced water dissolved CO<sub>2</sub> [Reserved]. *[WCI.363(v)]*
  - (23) Coal bed methane produced water emissions [Reserved]. *[WCI.363(v)]*
  - (24) Other venting emission sources.\* *[WCI.363(x)]*
  - (25) Other fugitive emission sources.\**[WCI.363(x)]*
- (d) For onshore natural gas processing, report CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions from the following sources:

- (1) Acid gas removal venting or incineration. *[WCI.363(c)]*
  - (2) Dehydrator vents. *[WCI.363(d)]*
  - (3) Blowdown vent stacks. *[WCI.363(g)]*
  - (4) Storage tanks. *[WCI.363(h)]*
  - (5) Flare stacks. *[WCI.363(k)]*
  - (6) Centrifugal compressor venting. *[WCI.363(l)]*
  - (7) Reciprocating compressor venting. *[WCI.363(m)]*
  - (8) Gathering pipeline fugitive equipment leaks. *[WCI.363(o)]* or *[WCI.363(x)]* for emission sources not covered by *[WCI.363(o)]*
  - (9) Fugitive equipment leaks from: valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.363(n)]*
  - (10) Other fugitive emission sources (including reciprocating compressor rod packing fugitives, centrifugal compressor dry and wet seals, etc).\**[WCI.363(x)]*
  - (11) Other venting emission sources.\**[WCI.363(x)]*
- (e) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. \*\*
- (f) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. \*\*
- (g) Report data for each aggregated source type within paragraph (b) through (d) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):
- (1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.
  - (2) Facility and company-specific emission factors or emissions information, as appropriate, used in place of Tables 360-1 and 360-2.

- (3) Count of natural gas pneumatic continuous high-bleed devices.
- (4) Count of natural gas pneumatic continuous low-bleed devices.
- (5) Count of natural gas intermittent (low and high) bleed devices.
- (6) Count of natural gas-driven pneumatic pumps.
- (7) Total throughput of acid gas removal units.
- (8) For each dehydrator unit report the following:
  - (i) Glycol dehydrators:
    - (A) The number of glycol dehydrators with throughput less than 11,328 Sm<sup>3</sup>/day operated, and
    - (B) The number of glycol dehydrators with throughput greater than or equal to 11,328 Sm<sup>3</sup>/day operated.
  - (ii) Desiccant dehydrators:
    - (A) The number of desiccant dehydrators operated.
- (9) Count of wells vented to the atmosphere for liquids unloading.
- (10) Count of third party line hits
  - (i) Engineering distribution of number of line hits by volume of gas released by hit
- (11) Count of wells venting during well completions:
  - (i) The number of conventional completions.
  - (ii) The number of completions employing hydraulic fracturing.
- (12) Count of wells venting during well workovers:
  - (i) The number well workovers involving well venting to the atmosphere.
- (13) For each compressor report the following:
  - (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal (for all compressors).
  - (ii) Compressor driver capacity in horsepower (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - (iii) Number of blowdowns per year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - (iv) Operating mode(s) (i.e., operating, not operating and pressurized or not operating and depressurized) during the year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - (v) Number of compressor starts per year.

- (14) Number of EOR injection pump blowdowns per year.
- (15) Count of wells tested in the reporting period.
- (16) Count of wells venting or flaring associated natural gas in the reporting period.
- (17) Count of wells being unloaded for liquids in the reporting year.
- (18) Count of wells completed (worked over) in the reporting year.
- (19) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in WCI.363(n) and (o), report the following:
  - (i) Major equipment (for 2011 and 2012 calendar year reporting) or component (for 2013 calendar year reporting and onwards) counts for which an emission factor is provided in Tables 360-1, 360-2 or 360-3 in this document. Default counts provided may be used for the 2011 and 2012 calendar years (reported in 2012 and 2013 in preparation for full component counts in the 2013 calendar year (reported in 2014). Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years.
  - (ii) Total counts of fugitive equipment leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- (20) Barrels of oil equivalent throughput/processed as determined by engineering estimate based on best available data.
- (21) Identification (including geographic coordinates) of any facility that had 1,000 tonnes or greater of greenhouse gas emissions in the previous year that was:
  - (i) Acquired during the reporting year;
  - (ii) Sold, decommissioned or shut-in during the reporting year;  
and,
  - (iii) The greenhouse gas emissions for the facility in the previous year.
  - (iv) The purchaser or seller, as appropriate

*\* Other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions, and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*\*\* Portable equipment is portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production facility. Stationary or portable equipment include the following equipment which are integral to the extraction, processing or movement of oil or natural gas: well drilling and completion*

*equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heater.s*

## § WCI.363 Calculating GHG Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or “not applicable”. Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 360-7.

(a) Natural gas pneumatic continuous high-bleed device venting Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator’s pneumatic high-bleed devices (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator’s pneumatic high-bleed devices. For the purposes of this reporting requirement, high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m<sup>3</sup>/hr . For unmetered devices the operator must use the method specified in paragraph (a)(2).

(1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

$$E_s = Q_j \quad \text{Equation 360-1}$$

Where:

$E_s$  = Annual natural gas volumetric emissions for pneumatic high-bleed devices and pneumatic pumps where gas is metered (Sm<sup>3</sup>/y).

$Q_j$  = Natural gas consumption for meter  $j$  (Sm<sup>3</sup>/y).

(2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

$$E_s = EF_j \times t_j$$

## Equation 360-2

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Natural gas-driven pneumatic device,  $j$ , bleed rate volume as provided by the manufacturer or in Table 360-6 ( $\text{Sm}^3/\text{h}/\text{device}$ ).
- $t_j$  = Total time that the pneumatic device,  $j$ , has been in service the (i.e. the time that gas flows to the device) through the reporting period (h).

- (3) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 360-5 for high-bleed pneumatic devices
- (4) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section
- (5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:
  - (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
  - (ii) In 2013, all continuous high-bleed natural gas pneumatic devices must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(a.1) Natural gas pneumatic pump venting. Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. By the start of the 2014 reporting year (January 1, 2014), natural gas consumption must be metered for 50 % of the operator's pneumatic pumps (the 50% calculation of metered devices may include devices that were operational on January 1, 2012 that are no longer operational as of January 1, 2014 due to phase out or not-operating). By the start of the 2015 reporting year (January 1, 2015), natural gas consumption must be metered for all of the operator's pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.

- (1) The operator must calculate vented emissions for metered pneumatic pumps using Equation 360-1.

- (2) The operator must calculate vented emissions for unmetered pneumatic pumps using Equation 360-3.
- (i) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer “gas consumption”) per unit volume of liquid circulation rate at pump speeds and operating pressures. If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.
  - (ii) Maintain a log of the amount of liquid pumped annually from individual pumps.
  - (iii) Calculate the natural gas emissions for each pump using Equation 360-3.

$$E_s = EF_j \times Q_j \quad \text{Equation 360-3}$$

Where:

- $E_s$  = Annual natural gas volumetric emissions ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Natural gas-driven pneumatic pump gas emission factor expressed in “emission per volume of liquid pumped at operating pressure” as provided by the manufacturer for pump  $j$  ( $\text{Sm}^3/\text{liter}$ ).
- $Q_j$  = Volume of liquid pumped annually by pump  $j$  (liters/y).

- (3) If manufacturer data for a specific pump, or reasonably similar pump model size and operational characteristics cannot be obtained; Equation 360-2 can be used with the population emission factor for natural gas-driven pneumatic pumps provided in Table 360-5.
- (4) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section
- (5) Provide the total number of natural gas pneumatic pumps as follows:
- (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining pumps.
  - (ii) In 2013, all natural gas pneumatic pumps must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.
- (b) Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using Equation 360-4 of this section.

$$E_s = EF_j \times t_j$$

### Equation 360-4

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic continuous low-bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Population emission factor for natural gas-driven pneumatic continuous low-bleed device,  $j$ , as provided in Table 360-5 ( $\text{Sm}^3/\text{h}/\text{device}$ ).
- $t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (1) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (2) Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:
  - (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
  - (ii) In 2013, all continuous low-bleed natural gas pneumatic devices must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(b.1) Natural gas pneumatic intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.

- (1) The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta-pressure or temperature using Equation 360-5:

$$E_s = EF_j \times t_j$$

### Equation 360-5

Where:

- $E_s$  = Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  = Emission factor for natural gas-driven pneumatic intermittent (low and high) bleed device,  $j$ , as provided in Table 360-6 ( $\text{Sm}^3/\text{h}/\text{device}$ ). If manufacturer data for a specific device is not available, then use data for a similar device

model, size and operational characteristics to estimate emissions. If data for a reasonably similar intermittent bleed device size and operational characteristics cannot be obtained, use the factor in Table 360-5 for intermittent bleed pneumatic devices.

$t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- (2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using Equation 360-6\*:

$$E_s = EF_j \times t_j$$

**Equation 360-6**

Where:

$E_s$  = Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices ( $\text{Sm}^3/\text{y}$ ).

$EF_j$  = Emission factor for natural gas-driven pneumatic compressor starter,  $j$ , as provided by the manufacturer ( $\text{Sm}^3/\text{min}/\text{device}$ ).

$t_j$  = Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

- (3) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:
- (i) In 2012, you may count 50% of the devices for each type of facility and engineering estimates can be used to determine both the denominator to be used in the 50% calculation and to estimate the number of remaining devices.
  - (ii) In 2013, all intermittent (low and high) bleed natural gas pneumatic devices must be counted.
  - (iii) In 2014, and for calendar years thereafter, facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

*\* for 2012, the volume of gas per start provided by the manufacturer may be used in place of the  $EF_j$  and  $t_j$  variables*

- (c) Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field or manifolded to a common flare stack, calculate  $\text{CO}_2$  emissions only (not  $\text{CH}_4$ ) for AGR (including but not limited to processes such as

amine, membrane, molecular sieve or other absorbents and adsorbents) using any of the calculation methodologies described in this section, as applicable.

- (1) Calculation Methodology 1. If you operate and maintain a CEMS on the AGR vent or incinerator stack that has both a CO<sub>2</sub> concentration analyzer and volumetric flow rate meter CO<sub>2</sub> emissions under this subpart must be calculated by following Calculation Methodology 4 and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Calculation Methodology 4 in WCI.20 (General Stationary Combustion). If a CO<sub>2</sub> concentration analyzer and volumetric flow rate meter are not available, a CO<sub>2</sub> concentration analyzer and a volumetric flow rate meter that comply with all of the requirements specified for the Calculation Methodology 4 in WCI.20 (General Stationary Combustion) may be installed.
- (2) Calculation Methodology 2. If CEMS is not available but a vent meter is available, use the CO<sub>2</sub> composition and annual volume of vent gas to calculate emissions using Equation 360-7.

$$E_{CO_2} = Q \times Y_{CO_2} \quad \text{Equation 360-7}$$

Where:

- $E_{CO_2}$  = Annual volumetric CO<sub>2</sub> emissions (Sm<sup>3</sup>/y).  
 $Q$  = Metered total annual volume of acid gas flow out of the AGR unit (Sm<sup>3</sup>/y) as determined in paragraph (c)(5) of this section.  
 $Y_{CO_2}$  = Mole fraction of CO<sub>2</sub> in acid gas out of the AGR unit as determined in paragraph (c)(6) of this section.

- (3) Calculation Methodology 3. If CEMS or a vent meter is not available, the inlet gas flow rate of the acid gas removal unit may be used to calculate emissions for CO<sub>2</sub> using Equation 360-8.

$$E_{CO_2} = \frac{Q_{in} \times [Y_{CO_2\_in} \times (1 - Y_{H_2S\_spec}) - Y_{CO_2\_out} \times (1 - Y_{H_2S\_in})]}{(1 - Y_{H_2S\_spec} - Y_{CO_2\_out})}$$

**Equation 360-8**

Where:

- $E_{CO_2}$  = Annual volumetric CO<sub>2</sub> emissions (Sm<sup>3</sup>/y).  
 $Q_{in}$  = Metered total annual volume of natural gas flow into the AGR unit (Sm<sup>3</sup>/y) as determined in paragraph (c)(5) of this section.

- $Y_{CO_2\_in}$  = Mole fraction of CO<sub>2</sub> in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.
- $Y_{CO_2\_out}$  = Mole fraction of CO<sub>2</sub> in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.
- $Y_{H_2S\_spec}$  = Mole fraction of H<sub>2</sub>S in the natural gas out of the AGR unit as defined by the performance specification of the AGR.
- $Y_{H_2S\_in}$  = Mole fraction of H<sub>2</sub>S in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.

- (4) Record the gas flow rate, referenced to standard conditions, of the inlet and outlet natural gas or acid gas stream of an AGR unit using a meter according to methods set forth in WCI.364(b).
  - (5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine  $Y_{CO_2\_in}$  according to methods set forth in WCI.364(b).
  - (6) Determine volume fraction of CO<sub>2</sub> content in natural gas or acid gas out of the AGR units using one of the methods specified in paragraph (c)(6) of this section.
    - (i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.
    - (ii) If a continuous gas analyzer is not available or installed, monthly gas samples must be taken from the outlet gas stream to determine  $Y_{CO_2}$  according to methods set forth in WCI.364(b).
  - (7) Determine volume fraction of H<sub>2</sub>S content in natural gas or acid gas into the AGR units using continuous gas analyzer data (if available), or other known or commonly accepted method (if continuous gas analyzer data is not available).
  - (8) Mass CO<sub>2</sub> emissions shall be calculated from volumetric CO<sub>2</sub> emissions using calculations in paragraph (s) of this section.
- (d) Dehydrator vents. For dehydrator vents, calculate annual mass CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) emissions as follows:
- (1) Calculate annual mass emissions from dehydrator vents using a simulation software package of similar accuracy to GRI-GLYCalc Version 4.0 or AspenTech HYSYS®, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH<sub>4</sub> and CO<sub>2</sub> emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection

pump or gas assist pump. A minimum of the following parameters must be used for characterizing emissions from dehydrators:

- (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 gas.
  - (viii) Use of flash tank separator (and disposition of recovered gas).
  - (ix) Hours operated.
  - (x) Wet natural gas temperature and pressure.
  - (xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(xi) of this section.
    - (A) Use the wet natural gas composition as defined in paragraph (r)(2)(i) of this section.
    - (B) If wet natural gas composition cannot be determined using paragraph (r)(2)(i) of this section, select a representative analysis.
    - (C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in WCI.364(b) to sample and analyze wet natural gas composition.
    - (D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.
- (2) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(4) of this section downward by the magnitude of emissions captured.
- (3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:
- (i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (d)(1) of this section.
  - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.
- (4) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 360-10.

$$E_s = \left( \frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times t} \right) / 100$$

**Equation 360-10**

Where:

$E_s$	=	Annual natural gas volumetric emissions ( $\text{Sm}^3/\text{y}$ ).
$H$	=	Height of the dehydrator vessel (m).
$D$	=	Inside diameter of the vessel (m).
$P_1$	=	Atmospheric pressure (kPa).
$P_2$	=	Pressure of the gas (kPa).
$\pi$	=	pi (3.14).
%G	=	Percent of packed vessel volume that is gas.
365	=	Conversion from days to years.
$t$	=	Time between refilling (days) ( $365/t$ represent the refilling times during the reporting year).
100	=	Conversion of %G to fraction.

(5) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(e) Well venting for liquids unloading. The  $\text{CO}_2$  and  $\text{CH}_4$  emissions for well venting for liquids unloading shall be determined using one of the following calculation methodologies:

(1) Calculation Methodology 1. For one representative well of each unique well tubing diameter grouping, pressure grouping and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank) according to the methods set forth in the WCI.364(b). Calculate emission from well venting for liquids unloading using Equation 360-11.

$$E_a = Q_j \times t_j$$

**Equation 360-11**

Where:

$E_a$	=	Annual natural gas volumetric emissions from well $j$ at actual conditions ( $\text{m}^3/\text{y}$ ).
$t_j$	=	Cumulative amount of time in hours of venting from well $j$ during the reporting period (h).
$Q_j$	=	Average flow rate of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (e)(1)(i) of this section ( $\text{m}^3/\text{h}$ ).

(i) Determine the well vent average flow rate as specified under paragraph (e)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter grouping and pressure grouping in each producing horizon/formation

combination in each producing field by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.

- (B) This average flow rate is applied to all wells in the same pressure grouping that have the same tubing diameter grouping, for the number of hours in the calendar year of venting these wells.
- (C) A new average flow rate is calculated every other calendar year (if necessary) for each reporting field and horizon combination starting the first calendar year of data collection. For a new producing reporting field and horizon combination, an average flow rate is calculated beginning in the first year of production.

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

- (2) Calculation Methodology 2. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 360-12.

$$E_{a,n} = \left( [7.854 \times 10^{-5}] \times D_t^2 \times WD \times \left[ \frac{P_{sales}}{101.325} \right] \times N_V \right) + (Q_{sfr} \times [t_{open} - 0.5] \times Z) \quad \text{Equation 360-12}$$

Where:

$E_a$	=	Annual natural gas volumetric emissions at actual conditions (m <sup>3</sup> /y).
$7.854 \times 10^{-5}$	=	$(\pi/4)/(10000)$
$D_t$	=	Tubing diameter (cm).
$WD$	=	Tubing depth to plunger bumper (meters).
$P_{sales}$	=	Sales line pressure (kPa-gage).
$N_V$	=	Number of vents per year.
$Q_{sfr}$	=	Average sales flow rate of gas well at actual conditions (m <sup>3</sup> /h).
$t_{open}$	=	Hours that the well was left open to the atmosphere during unloading.
0.5	=	Hours for average well to blowdown tubing volume at sales line pressure.
$Z$	=	If $t_{open}$ is less than 0.5 then $Z$ is equal to 0. If $t_{open}$ is greater than or equal to 0.5 then $Z$ is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

- (4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

(f) Gas well venting during well completions and workovers. Calculate emissions from gas conventional or unconventional (from hydraulic fracturing) well venting during well completions and workovers using one of the following methods. Sum all events to determine total annual venting that occurred in the reporting year. For 2012 calendar year emissions reporting, in addition to WCI.363(f)(1) and (2), methods published in the December 17, 2010 version of this document may be used for quantifying emissions from gas well venting during well completions and workovers.

(1) Calculation Methodology 1.

- (i) The operator must measure total gas flow with a recording flow meter (analog or digital) installed in the vent line.
- (ii) The operator must correct total gas volume vented for the volume of CO<sub>2</sub> or N<sub>2</sub> injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{CO_2, N_2} - V_{SG}$$

**Equation 360-13**

Where:

- E<sub>a</sub> = Natural gas emissions during the well completion or workover at actual conditions (m<sup>3</sup>).
- V<sub>M</sub> = Volume of vented gas measured during well completion or workover (m<sup>3</sup>).
- V<sub>CO<sub>2</sub>,N<sub>2</sub></sub> = Volume of CO<sub>2</sub> or N<sub>2</sub> injected during well completion or workover (m<sup>3</sup>).
- V<sub>SG</sub> = Volume of natural gas recovered into a sales pipeline (m<sup>3</sup>).

- (iii) All gas volumes must be corrected to standard temperature and pressure using methods in paragraph (q) of this section.
- (iv) The operator must calculate CO<sub>2</sub> and CH<sub>4</sub> mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.

(2) Calculation Methodology 2.

- (i) The operator must make a series of measurements of upstream pressure (P<sub>1</sub>) and downstream pressure (P<sub>2</sub>) across a choke installed in the vent line and upstream gas temperature according to methods in section WCI.364(b) during each well completion and well workover where venting occurs. The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes. Sonic flow is defined as the flow regime where P<sub>2</sub>/P<sub>1</sub> ≤ 0.542. Subsonic flow is defined as the flow regime where P<sub>2</sub>/P<sub>1</sub> > 0.542. The operator must then calculate flow rate for both sonic and subsonic flow regimes using the following equations:

A. Sonic flow regime.

1. The operator must calculate the average flow rate during sonic flow conditions as follows:

$$Q_{S,avg} = 3600 \times A \times \sqrt{187.08 \times T_u}$$

**Equation 360-14**

Where:

- $Q_{S,avg}$  = Average flow rate of natural gas during sonic flow conditions (m<sup>3</sup>/h).  
 3600 = Conversion factor from m<sup>3</sup>/second to m<sup>3</sup>/hour.  
 A = Cross sectional area of the orifice (m<sup>2</sup>).  
 187.08 = Constant with units of m<sup>2</sup>/(sec<sup>2</sup>\*K)  
 T<sub>u</sub> = Upstream gas temperature (degrees Kelvin).

2. The operator must calculate total natural gas volume vented during sonic flow conditions as follows:

$$V_S = Q_{S,avg} \times t_S$$

**Equation 360-15**

Where:

- V<sub>s</sub> = Volume of gas vented during sonic flow conditions (m<sup>3</sup>)  
 t<sub>s</sub> = Duration of venting during sonic flow conditions (h). The operator must correct Q<sub>s</sub> to standard conditions using the methodology in paragraph (q) of this section

**B. Subsonic flow regime.**

1. The operator must calculate the instantaneous gas flow rate during subsonic flow conditions as follows:

$$Q_{SS,inst} = 3600 \times A \times \sqrt{3430 \times T_u \left[ \left( \frac{P_2}{P_1} \right)^{1.515} - \left( \frac{P_2}{P_1} \right)^{1.758} \right]}$$

**Equation 360-16**

Where:

- $Q_{SS,inst}$  = Instantaneous flow rate of natural gas at time t<sub>inst</sub> during subsonic flow conditions (m<sup>3</sup>/h).  
 3600 = Conversion factor from m<sup>3</sup>/second to m<sup>3</sup>/hour.  
 A = Cross sectional area of the orifice (m<sup>2</sup>).  
 3430 = Constant with units of m<sup>2</sup>/(sec<sup>2</sup>\*K)

- $T_u$  = Upstream gas temperature (degrees Kelvin).  
 $P_2$  = Downstream pressure (kPa)  
 $P_1$  = Upstream pressure (kPa)

2. The operator must determine total gas volume vented during subsonic flow conditions ( $V_{ss}$ ) as the total volume under the curve of a plot of  $Q_{ss,inst}$  and time ( $t_{inst}$ ) for the time period during which the well was flowing during subsonic conditions.
  3. The operator must correct  $V_{SS}$  to standard conditions using the methodology in paragraph (q) of this section
- (ii) The operator must sum the vented volumes during sonic and subsonic flow and adjust emissions for the volume of  $CO_2$  or  $N_2$  injected and the volume of gas recovered into a sales line as follows:

$$E_s = V_s + V_{SS} - V_{CO_2, N_2} - V_{SG}$$

**Equation 360-17**

Where:

- $E_s$  = Natural gas emissions during the well completion or workover ( $Sm^3$ ).  
 $V_s$  = Volume of gas vented during sonic flow conditions ( $Sm^3$ )  
 $V_{SS}$  = Volume of gas vented during subsonic flow conditions ( $Sm^3$ )  
 $V_{CO_2, N_2}$  = Volume of  $CO_2$  or  $N_2$  injected during well completion or workover ( $Sm^3$ ).  
 $V_{SG}$  = Volume of natural gas recovered into a sales pipeline ( $Sm^3$ ).

- (iii) The operator must calculate  $CO_2$  and  $CH_4$  mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.
- (3) Calculate annual emissions from gas well venting during well completions and workovers to flares as follows:
- (i) Use the gas well venting volume during well completions and workovers as determined in paragraph (f)(1) or (f)(2) of this section.
  - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine gas well venting during well completions and workovers emissions from the flare.
- (g) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (d)(4) of this section) as follows:

- (1) Calculate the total physical volume (including, but not limited to, pipe, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.
- (2) If the total physical volume between isolation valves is greater than or equal to 1.42 Sm<sup>3</sup>, retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m<sup>3</sup> are exempt from reporting under paragraph (g) of this section.
- (3) Calculate the venting emissions for each equipment type using Equation 360-18.

$$E_s = V_v \left[ \frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)P_s} \right]$$

**Equation 360-18**

Where:

- $E_s$  = Natural gas venting volumetric emissions from blowdown of an equipment system (Sm<sup>3</sup>).
- $V_v$  = Total physical volume of blowdown equipment chambers (including, but not limited to, yard piping, pipelines, compressors and vessels) between isolation valves for the equipment system (m<sup>3</sup>).
- $T_s$  = Temperature at standard conditions (°C).
- $T_a$  = Temperature at actual conditions in the equipment system (°C).
- $P_s$  = Absolute pressure at standard conditions (kPaa).
- $P_{a,1}$  = Absolute pressure at actual conditions in the equipment system prior to depressurization (kPaa).
- $P_{a,2}$  = Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPaa).

- (4) Calculate both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (5) Blowdowns that are directed to flares use the WCI.363(k) Flare stacks calculation method rather than WCI.363(g) Blowdown vent stacks calculation method.

(g.1) Third party line hits. Calculate emissions from third party line hits as follows:

- (1) For each dig-in incident (i.e., line hit) which results in gas release  $\geq 1.416$  Sm<sup>3</sup>, calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline

ruptures and pipeline puncture incidents using the appropriate methodology below<sup>1</sup>. For 2012, the methodology in paragraph (iv) may be used in addition to those in paragraphs (i) and (ii).

- (i) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

$$Q_s = \frac{3.6 \times 10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

**Equation 360-19**

Where:

$$M = \sqrt{\frac{2 \left[ \left( \frac{P_a}{P_e} \right)^{\frac{K-1}{K}} - 1 \right]}{K-1}}, \text{ (for } M \leq 1),$$

**Equation 360-20**

M = 1, (for all other cases)

Where:

$Q_s$	=	natural gas venting volumetric flow rate ( $\text{Sm}^3/\text{h}$ )
A	=	cross-sectional flow area of the pipe ( $\text{m}^2$ , $A = \pi D^2/4000$ )
D	=	inside diameter of the pipe (mm)
K	=	specific heat ratio of the gas (dimensionless – 1.299 for methane)
M	=	Mach number of the flow (m/s)
MW	=	molecular weight of the gas (kg/mole, 16.043 kg/mole for methane)
$P_e$	=	pressure at the damage point (local atmospheric pressure, kPaa)
$P_a$	=	pressure inside the pipe at supply (kPaa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
R	=	universal gas constant ( $8.3145 \text{ kPam}^3/\text{kmol/K}$ )
$T_a$	=	temperature inside pipe at the supply ( $^{\circ}\text{C}$ )
$\rho_s$	=	gas density at standard conditions ( $\text{kg/m}^3$ ) ( $0.6785 \text{ kg/m}^3$ for $\text{CH}_4$ )

<sup>1</sup> Methodology Manual, Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

(ii) For pipeline punctures use the following methodology (for flows not choked):

$$Q_s = \frac{A_e}{\rho_s} \sqrt{\frac{2000 \cdot K}{K-1} P_a \rho_a \left[ \left( \frac{P_{Atm}}{P_a} \right)^{2/K} - \left( \frac{P_{Atm}}{P_a} \right)^{(K+1)/K} \right]}$$

**Equation 360-21**

Where:

$$\left( \frac{P_{Atm}}{P_a} \right) \geq \left( \frac{P_{Atm}}{P_a} \right)_{choked} = \left( \frac{2}{K+1} \right)^{K/(K-1)} = 0.546 \quad (\text{for methane})$$

**Equation 360-22**

Where:

$A_e$	=	size of the hole in the pipe ( $m^2$ )
$P_a$	=	pressure inside the pipe at the puncture location (kPaa)
$\rho_a$	=	gas density inside the pipe at the puncture location ( $kg/m^3$ )
MW	=	molecular weight of the natural gas (16.043 for methane)
$T_a$	=	temperature inside the pipe ( $^{\circ}C$ )
$(P_{ATM}/P_a)_c$	=	0.546 - lower limit for choked flow

(iii) Check for choked flow

(A) If  $(P_{ATM}/P_a) \geq 0.546$  flow is not choked and the reporter must use the equations in section (g.1)(ii) above.

(B) If  $(P_{ATM}/P_a) < 0.546$  flow is choked and A must be set to the cross sectional flow area of the pipe and the reporter must use the equations in section (g.1)(i) above.

(iv) For 2012 calendar year emissions, an operator may use other methods to calculate emissions published in the CEPEI Methodology Manual, or other industry standard reference sources.

(v) Calculate volumetric natural gas emissions by multiplying  $Q_s$  for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.

(vi) Calculate GHG ( $CH_4$  and  $CO_2$  emissions) mass emissions using the methodologies in sections (r) and (s) of this section.

(h) Onshore production and processing storage tanks. For emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, calculate annual  $CH_4$ ,  $CO_2$  (and  $N_2O$ , when flared) emissions as specified in either paragraphs (h)(1) or (h)(2). For atmospheric storage tanks vented to flares, use the calculation methodology for flare stacks in paragraph (k) of this section. Storage tanks equipped with vapour recovery units (VRU) are exempt from the requirements of this paragraph. For 2012 calendar year emissions reporting, Equation 360-12, as published in the December 17, 2010 version of this

document, may also be used for quantifying emissions from onshore production and processing storage tanks.

- (1) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing emissions using Equation 360-23.

$$E_i = GOR \times Q_o \times Y_i \times \rho_i \times 0.001$$

**Equation 360-23**

Where:

E <sub>i</sub>	=	Annual emissions of greenhouse gas <i>i</i> (CO <sub>2</sub> or CH <sub>4</sub> ) (tonnes/y).
GOR	=	Gas Oil Ratio (Sm <sup>3</sup> gas/m <sup>3</sup> oil) measured following WCI.364(f).
Q <sub>o</sub>	=	Oil production rate (m <sup>3</sup> /y).
ρ <sub>i</sub>	=	Density of GHG <i>i</i> (1.861 kg/m <sup>3</sup> for CO <sub>2</sub> and 0.678 kg.m <sup>3</sup> for CH <sub>4</sub> at standard conditions of 101.325 kPa and 15 °C).
Y <sub>i</sub>	=	Mole fraction of greenhouse gas <i>i</i> (CO <sub>2</sub> or CH <sub>4</sub> ) in tank vapour.
0.001	=	Conversion factor (tonnes/kg).

- (2) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing emissions using the latest software package for E&P Tank. A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.
  - (i) Separator oil composition.
  - (ii) Separator temperature.
  - (iii) Separator pressure.
  - (iv) Sales oil API gravity.
  - (v) Sales oil production rate.
  - (vi) Sales oil Reid vapour pressure.
  - (vii) Ambient air temperature.
  - (viii) Ambient air pressure.

(h.1) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in onshore natural gas production and processing facilities calculate CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) annual emissions from compressor scrubber dump valve leakage as follows. For 2012, other methodologies may be used to quantify emissions from transmission storage tanks in addition to those outlined below.

- (1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in WCI.364(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in WCI.364(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in WCI.364(a)(4).

- (2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (h.1)(2) of this section to quantify annual emissions:
- (i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in WCI.364(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (h.1)(1) of this section to detect continuous leakage, this serves as the measurement.
  - (ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in WCI.364(a)(4).
  - (iii) Use the appropriate gas composition in paragraph (r) of this section.
- (3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.
- (4) Calculate annual emissions from storage tanks to flares as follows:
- (i) Use the storage tank emissions volume and gas composition as determined in paragraphs (h.1)(1) through (h.1)(3) of this section.
  - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine storage tank emissions sent to a flare.
- (i) Well testing venting and flaring. Calculate CH<sub>4</sub>, CO<sub>2</sub>, and N<sub>2</sub>O (when flared) well testing venting and flaring emissions as follows.
- (1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.
  - (2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (i)(2) of this section to determine GOR and follow paragraph (3). Otherwise follow paragraph (4).:
    - (i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
    - (ii) Or you may use an industry standard practice as described in WCI.364(b).
  - (3) Calculation Methodology 1. Estimate venting emissions using Equation 360-24.

$$E_a = GOR \times Q_o \times t$$

**Equation 360-24**

Where:

$E_a$	=	Annual volumetric natural gas emissions from well testing at actual conditions ( $m^3/y$ ).
GOR	=	Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities ( $m^3 \text{ gas}/m^3 \text{ oil}$ ).
$Q_o$	=	Flow rate for the well being tested ( $m^3 \text{ oil}/h$ ).
$t$	=	Total hours during the year the well is tested (h).

- (4) Calculation Methodology 2. In cases where very little hydrocarbon liquids are produced and the GOR approaches infinity, estimate emissions using Equation 360-25. A recording flow meter shall be installed on the vent (or flare) line used to vent gas from the well (e.g. on the vent line off the well-test separator) according to the methods set forth in the WCI.364(b).

$$E_a = Q_g \times t$$

**Equation 360-25**

Where:

$E_a$	=	Annual natural gas volumetric emissions at actual conditions ( $m^3/y$ ).
$t$	=	Total hours during the year the well is tested (h).
$Q_g$	=	Average flow rate of the measured well venting for the duration of the test at actual conditions ( $m^3 \text{ gas}/h$ ).

- (5) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (6) Calculate both  $CH_4$  and  $CO_2$  volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (7) Calculate emissions from well testing to flares as follows:
- Use the well testing emissions volume as determined in paragraphs (i)(1) through (4) of this section.
  - Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing gas composition and emissions from the flare.
- (j) Associated gas venting and flaring. Calculate associated gas venting and flaring emissions not in conjunction with well testing (refer to section (i): Well testing venting and flaring) as follows.
- Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.
  - If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (j)(2) of this section to determine GOR:

- (i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
  - (ii) Or you may use an industry standard practice as described in WCI.364(b).
- (3) Estimate venting emissions using the Equation 360-26.

$$E_a = GOR \times Q_o$$

**Equation 360-26**

Where:

- $E_a$  = Annual volumetric natural gas emissions from associated gas venting at actual conditions ( $m^3/y$ ).
- GOR = Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities ( $m^3 \text{ gas}/m^3 \text{ oil}$ ).
- $Q_o$  = Total volume of oil produced for the calendar year during which associated gas was flared or vented ( $m^3 \text{ oil}/y$ ).

- (4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (5) Calculate both  $CH_4$  and  $CO_2$  volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (6) Calculate emissions from associated natural gas to flares as follows:
  - (i) Use the associated natural gas volume as determined in paragraph (j)(1) through (4) of this section.
  - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine associated gas composition and emissions from the flare.

(k) Flare stacks. Calculate  $CO_2$ ,  $CH_4$ , and  $N_2O$  emissions from a flare stack as follows.

- (1) If there is a continuous flow measurement device on the flare, measured flow volumes must be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or engineering calculations based on process knowledge, company records, and best available data.
- (2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:
  - (i) For onshore natural gas production, determine natural gas composition using (r)(2)(i) of this section.
  - (ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-

methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

- (iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus, and mixed light hydrocarbons then a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data may be used.
- (3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.
- (4) Calculate GHG volumetric emissions at actual conditions using Equations 360-27, 360-28, 360-29, and 360-30.

$$E_{s,CH_4}(\text{noncombusted}) = Q_s \times (1 - \eta) \times Y_{CH_4} \quad \text{Equation 360-27}$$

$$E_{s,CO_2}(\text{noncombusted}) = Q_s \times Y_{CO_2} \quad \text{Equation 360-28}$$

$$E_{s,CO_2}(\text{combusted}) = \sum_i \eta \times Q_s \times Y_i \times n_i \quad \text{Equation 360-29}$$

$$E_{s,CO_2}(\text{total}) = E_{s,CO_2}(\text{combusted}) + E_{s,CO_2}(\text{noncombusted}) \quad \text{Equation 360-30}$$

Where:

$E_{s,CH_4}(\text{noncombusted})$	=	Contribution of annual noncombusted volumetric CH <sub>4</sub> emissions from flare stack (Sm <sup>3</sup> ).
$E_{s,CO_2}(\text{noncombusted})$	=	Contribution of annual volumetric CO <sub>2</sub> emissions from CO <sub>2</sub> in the inlet gas passing through the flare noncombusted (Sm <sup>3</sup> ).
$E_{s,CO_2}(\text{combusted})$	=	Contribution of annual CO <sub>2</sub> emissions from combustion from flare stack under ambient conditions (Sm <sup>3</sup> ).
$Q_s$	=	Volume of natural gas sent to flare during the year (Sm <sup>3</sup> ).
$\eta$	=	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, $\eta$ is zero.
$Y_{CH_4}$	=	Mole fraction of CH <sub>4</sub> in gas to the flare.
$Y_{CO_2}$	=	Mole fraction of CO <sub>2</sub> in gas to the flare.
$Y_i$	=	Mole fraction of hydrocarbon constituents $i$ (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
$n_i$	=	Number of carbon atoms in the hydrocarbon constituent $i$ (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for

pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

- (5) Calculate both CH<sub>4</sub> and CO<sub>2</sub> mass emissions from volumetric CH<sub>4</sub> and CO<sub>2</sub> emissions using calculation in paragraph (s) of this section.
- (6) Calculate N<sub>2</sub>O emissions using Equation 360-31.

$$E_{N_2O} = Q_s \times HHV \times EF \times 0.001$$

**Equation 360-31**

Where:

- $E_{N_2O}$  = Annual N<sub>2</sub>O mass emissions from flaring (tonnes/y).  
 $Q_s$  = Volume of gas combusted by the flare in the reporting period (Sm<sup>3</sup>/y).  
 $HHV$  = High heat value of the flared gas from paragraph (k)(2).  
 $EF$  = N<sub>2</sub>O emission factor. Use  $9.52 \times 10^{-5}$  kg N<sub>2</sub>O/GJ.  
 0.001 = Conversion factor from kilograms to tonnes.

- (7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in WCI.363. Where gas to be flared is manifolded from multiple sources in WCI.363 to a common flare, report all flaring emissions under WCI.363(k).

- (l) Centrifugal compressor venting. Calculate emissions from centrifugal compressor venting as follows.

- (1) The operator must calculate CO<sub>2</sub>, and CH<sub>4</sub>, and N<sub>2</sub>O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degasing) where the aggregate rated power for the sum of compressors at the facility is 186.4 kW or greater using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.364(b).
- (2) Estimate annual emissions using flow meter measurement using Equation 360-32.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

**Equation 360-32**

Where:

- $E_{s,i}$  = Annual volumetric emissions of GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>) from all measured compressor venting modes (Sm<sup>3</sup>/y).

$Q_{s,m}$	=	Measured volumetric gas emissions during operating mode $m$ described in paragraph (l)(4) of this section ( $\text{Sm}^3/\text{h}$ ).
$t_m$	=	Total time the compressor is in operating mode $m$ during the calendar year (h).
$Y_i$	=	Mole fraction of GHG $i$ in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
CF	=	Fraction of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents), unit isolation-valve vents, and blowdown-valve vents.
- (i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.
  - (ii) Operating mode.
  - (iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.
- (A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode
- (5) The operator must calculate  $\text{CO}_2$ , and  $\text{CH}_4$ , and  $\text{N}_2\text{O}$  (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) for all compressors where the aggregate rated power for the sum of compressors at the facility is less than 186.4 kW (250 hp) using Equation 360-33.

$$E_{s,i} = \text{Count} \times EF_i$$

**Equation 360-33**

Where:

- $E_{s,i}$  = Annual total volumetric GHG emissions at standard conditions from centrifugal compressors ( $m^3/\text{year}$ ).
- Count = Total number of centrifugal compressors less than 186.4 kW.
- $EF_i$  = Emission factor for GHG  $i$  (either  $\text{CH}_4$  or  $\text{O}_2$ ). Use 339,573.2  $\text{Sm}^3/\text{year}$  per compressor for  $\text{CH}_4$  and 14,974.7  $\text{Sm}^3/\text{year}$  per compressor for  $\text{CO}_2$  at 15 °C and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law.

- (6) Calculate both  $\text{CH}_4$  and  $\text{CO}_2$  mass emissions from volumetric emissions using calculations in paragraph (s) of this section.
- (7) Calculate emissions from degassing vent vapours to flares as follows:
- Use the degassing vent vapour volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.
  - Use the calculation methodology of flare stacks in paragraph (k) of this section to determine degassing vent vapour emissions from the flare.

(m) Reciprocating compressor venting. Calculate annual  $\text{CH}_4$  and  $\text{CO}_2$  emissions from all reciprocating compressor vents as follows, except as specified in paragraph (m)(7). Where venting emissions are sent to a common flare, calculate emissions using WCI.363(k).

- (1) Estimate annual emissions using the flow measurement in (m)(2) or (m)(3) below and Equation 360-34.

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

**Equation 360-34**

Where:

- $E_{s,i}$  = Annual volumetric emissions of GHG  $i$  (either  $\text{CH}_4$  or  $\text{CO}_2$ ) from all measured compressor venting modes ( $\text{Sm}^3/\text{y}$ ).
- $Q_{s,m}$  = Measured volumetric gas emissions during operating mode  $m$  described in paragraph (m)(4) ( $\text{Sm}^3/\text{h}$ ).
- $t_m$  = Total time the compressor is in operating mode  $m$  during the calendar year (h).
- $Y_i$  = Mole fraction of GHG  $i$  in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
- CF = Fraction of reciprocating compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system. An engineering estimation approach may be used for the CF parameter for 2012 emissions reporting.

- (2) If the reciprocating rod packing and blowdown vent is connected to an open-ended vent line then use one of the following two methods to calculate emissions.
  - (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or High-flow Sampler according to methods set forth in WCI.364(c) and (d).
  - (ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.364(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.364(a).
- (3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:
  - (i) Use the methods described in WCI.364(a) to conduct a progressive leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
  - (ii) Measure emissions using a High-flow Sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.364(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (m)(7) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents.
  - (i) Operating or standby-pressurized mode, blowdown vent leakage through the blowdown vent stack.
  - (ii) Operating mode, reciprocating rod-packing emissions.
  - (iii) Not operating, depressurized mode, unit isolation-valve leakage through the blowdown vent stack, without blind flanges.
    - (A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode
- (5) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.
- (6) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

- (i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.
  - (ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year
- (7) Onshore petroleum and natural gas production may calculate emissions from reciprocating compressors where the aggregate rated power for the sum of compressors at the facility is less than 186.4 kW (250 hp) as follows using Equation 360-35:

$$E_{s,i} = Count \times EF_i$$

**Equation 360-35**

Where:

- $E_{s,i}$  = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors ( $m^3/year$ ).
- Count = Total number of reciprocating compressors considered under (m)(7) for the reporter.
- $EF_i$  = Emission factor for GHG  $i$  (either  $CH_4$  or  $O_2$ ). Use  $268.0 Sm^3/year$  per compressor for  $CH_4$  and  $14.9 Sm^3/year$  per compressor for  $CO_2$  at  $15\text{ }^\circ C$  and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law.

- (n) Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in WCI.364(a)(0.1) or progressive sampling methods (described in WCI.364(a)(0.2)) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in §WCI.362(d)(9). This paragraph (n) applies to emissions sources in streams with gas containing greater than 10 percent  $CH_4$  plus  $CO_2$  by weight. Emissions sources in streams with gas containing less than 10 percent  $CH_4$  plus  $CO_2$  by weight need to be reported instead under paragraph (x) of this section. \*\*

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using Equation 360-36 for each source with fugitive equipment leaks.

$$E_{s,i} = EF_{s,l} \times Y_i \times t_1$$

**Equation 360-36**

Where:

$E_{s,i}$	=	Annual total volumetric emissions of GHG $i$ (either CH <sub>4</sub> or CO <sub>2</sub> ), from each fugitive equipment leak source (Sm <sup>3</sup> /y).
$EF_{s,l}$	=	Leaker volumetric emission factor for specific component, $l$ , listed in 40 CFR Part 98 Table W-2, relevant Canadian Association of Petroleum Producers (CAPP) methodology manuals, if available or facility/company-specific emission factors* used (as converted for use in Equation 360-36).
$Y_i$	=	For onshore natural gas processing facilities, mole fraction of GHG $i$ (either CH <sub>4</sub> or CO <sub>2</sub> ) in the total hydrocarbon of the feed natural gas.
$t_l$	=	Total time the component, $l$ , was found leaking and operational (hours). If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the last survey during which it was determined to be not leaking, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.

- (1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (s) of this section.
- (2) Onshore natural gas processing facilities shall use the appropriate default volumetric leaker emission factors listed in 40 CFR Part 98 Table W-2 (as converted to metric) or relevant Canadian Association of Petroleum Producer methodology manuals, if available for fugitive equipment leaks detected from valves; connectors; open ended lines; pressure relief valves; and meters.

*\* component-specific emission factors may equal leak rates quantified, following WCI.364(c) or (d), during leak detection surveys.*

*\*\* tubing systems less than one half inch diameter may be quantified using WCI.363(n), instead of WCI.363(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.363(x). Reporting must occur using the appropriate section of WCI.362, dependent upon quantification method used.*

- (o) Population count and emission factors. This paragraph applies to emissions sources listed in §WCI.362 (c)(16), (c)(17) and (d)(8) on streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight do not need to be reported. \*\*

- (1) Calculate emissions from all sources listed in this paragraph using Equation 360-37 except for emissions from underground gathering pipelines that are calculated in paragraph (2).

$$E_i = \sum_k \sum_l \left( N_{k,l} \times \frac{EF_{k,l}}{THC_k} \times X_{i,k} \right) \times t$$

**Equation 360-37**

Where:

- $E_i$  = Annual total mass emissions of GHG  $i$  (CH<sub>4</sub> or CO<sub>2</sub>) at standard conditions from each major equipment or component count fugitive source at the facility (tonnes/year).
- $N_{k,l}$  = Number of components in service  $k$  and component type  $l$ . Per WCI.362(g)(19) average component counts by major equipment pieces for Canada from Table 360-3 may be used for 2011 and 2012 calendar year emissions as appropriate and can be in Gas/Vapour, Fuel Gas and Liquid service. For 2013 calendar year emissions and onwards component counts for individual facilities must be used. If facility or company specific major equipment count data that meet or exceed the quality of the relevant default count data are available, they must be used instead. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years
- $EF_{k,l}$  = Population mass emission factor for components in service  $k$  and component type  $l$  listed in Table 360-1 or Table 360-2. The direction on the use of Tables 360-1 and 360-2 provided prior to these tables must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used\* (tonnes total hydrocarbon (THC) / component / h).
- $THC_k$  = Mass fraction of total hydrocarbons in service  $k$ .
- $X_{i,k}$  = Mass fraction of GHG  $i$  (CH<sub>4</sub> or CO<sub>2</sub>) in service  $k$ .
- $t$  = Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (h).

- (2) Calculate emissions from underground gathering pipelines using Equation 360-38.

$$E_{s,i} = EF_{s,i} \times L \times t$$

**Equation 360-38**

Where:

- $E_{s,i}$  = Annual total volumetric emissions of GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>), from an underground gathering pipeline (Sm<sup>3</sup>/y).
- $EF_{s,i}$  = Volumetric emission factors equal to 2.66 x 10<sup>-5</sup> t CH<sub>4</sub>/km/h and 3.63 x 10<sup>-6</sup> t CO<sub>2</sub>/km/h for pipeline leaks plus the portion of methane emitted from

underground leaks that is oxidized to form carbon dioxide and equal to  $2.72 \times 10^{-6}$  t CO<sub>2</sub>/km/h. These factors are published in Table 6-4 of the American Petroleum Institute (API) 2009 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry.

L = Length of the underground gathering pipeline (km)  
t = Total time the underground gathering pipeline was operational in the reporting year (h).

(3) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 360-1 or 360-2 for fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other equipment. Where facilities conduct EOR operations the emissions factors listed in Table 360-1 or Table 360-2 shall be used to estimate all streams of gases, including the recycle CO<sub>2</sub> stream. The component count can be determined using either of the methodologies described in this paragraph (o)(1). The same methodology must be used for the entire calendar year..

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table 360-3 of this section.

(B) Multiply major equipment counts by the average component counts in Gas/Vapour, Fuel Gas and Liquid service listed in Table 360-3 of this section for onshore natural gas production and onshore oil production, respectively. Use the appropriate total hydrocarbon (THC) factor in Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

*\* facility/company-specific emission factors may equal leak rates quantified, following WCI.364(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of WCI.367 – Directions for the use of Tables 360-1 and 360-2.*

*\*\* tubing systems less than one half inch diameter may be quantified using WCI.363(n), instead of WCI.363(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using WCI.363(x). Reporting must occur using the appropriate section of WCI.362, dependent upon quantification method used.*

(p) Offshore petroleum and natural gas production facilities in both provincial and federal waters.

[reserved]

(q) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2), with actual pressure and temperature determined by engineering estimate based on best available data unless otherwise specified.

- (1) Calculate natural gas volumetric emissions at standard conditions by converting the actual temperature and pressure to standard temperature and pressure (15 °C and 1 atmosphere in Canada) using Equation 360-39 of this section.

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

**Equation 360-39**

Where:

$E_s$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).
$E_a$	=	Natural gas volumetric emissions at actual conditions ( $\text{m}^3$ ).
$T_s$	=	Temperature at standard conditions ( $^{\circ}\text{C}$ ).
$T_a$	=	Temperature at actual emission conditions ( $^{\circ}\text{C}$ ).
$P_s$	=	Absolute pressure at standard conditions (kPa).
$P_a$	=	Absolute pressure at actual conditions (kPa).

- (2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using Equation 360-40.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

**Equation 360-40**

Where:

$E_{s,i}$	=	GHG $i$ volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).
$E_{a,i}$	=	GHG $i$ volumetric emissions at actual conditions ( $\text{m}^3$ ).
$T_s$	=	Temperature at standard conditions ( $^{\circ}\text{C}$ ).
$T_a$	=	Temperature at actual emission conditions ( $^{\circ}\text{C}$ ).
$P_s$	=	Absolute pressure at standard conditions (kPa).
$P_a$	=	Absolute pressure at actual conditions (kPa).

- (r) GHG volumetric emissions. If the GHG volumetric emissions at actual conditions are known, follow the method in (q)(2) to calculate their emissions at standard conditions. If the GHG volumetric emissions are not yet known, then follow the methods below to calculate

GHG volumetric emissions at standard conditions as specified in paragraphs (r)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

- (1) Estimate CH<sub>4</sub> and CO<sub>2</sub> emissions from natural gas emissions using Equation 360-41.

$$E_{s,i} = E_s \times Y_i$$

**Equation 360-41**

Where:

- $E_{s,i}$  = GHG *i* (CH<sub>4</sub> or CO<sub>2</sub>) volumetric emissions at standard conditions.  
 $E_s$  = Natural gas volumetric emissions at standard conditions.  
 $Y_i$  = Mole fraction of GHG *i* in the natural gas.

- (2) For Equation 360-41 of this section, the mole fraction,  $Y_i$ , shall be the annual average mole fraction for each facility, as specified in paragraphs (r)(2)(i) and (ii) of this section.
- (i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in WCI.364(b). Alternatively, if this information is not available, the composition for the specific field from Table 360-4.
- (ii) (a) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and (b) GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use an annual average of these values to determine the mole fraction in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field must be used as taken according to methods set forth in WCI.364(b). If such information is not available, then the composition for the specific field can be referenced from Table 360-4.

- (s) GHG mass emissions. Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 360-42.

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

**Equation 360-42**

Where:

- $E_i$  = GHG  $i$  (either CH<sub>4</sub>, CO<sub>2</sub>, or, N<sub>2</sub>O) mass emissions (tonnes CO<sub>2</sub>e).  
 $E_{s,i}$  = GHG  $i$  (either CH<sub>4</sub>, CO<sub>2</sub>, or, N<sub>2</sub>O) volumetric emissions (Sm<sup>3</sup>).  
 $\rho_{s,i}$  = Density of GHG  $i$ , (1.861 kg/m<sup>3</sup> for CO<sub>2</sub> and 0.678 kg/m<sup>3</sup> for CH<sub>4</sub> at standard conditions of  $T_s = 15^\circ\text{C}$  and  $P_s = 101.325 \text{ kPa}$ )

$$= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

- $GWP_i$  = Global warming potential of GHG  $i$  (1 for CO<sub>2</sub> and 21 for CH<sub>4</sub>, and 310 for N<sub>2</sub>O).  
 $MW_i$  = Molecular weight for GHG <sub>$i$</sub>  taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).  
 $R_u$  = Universal gas constant (8.31434 kJ/kmole K)  
0.001 = Conversion factor from kilograms to tonnes.

- (t) EOR injection pump blowdown. Calculate pump blowdown emissions as follows:

- (1) Calculate the total volume in cubic meters (including, but not limited to, pipelines, manifolds and vessels) between isolation valves.
- (2) Retain logs of the number of blowdowns per reporting period.
- (3) Calculate the total annual venting emissions using Equation 360-43.

$$E_i = N \times V_v \times \rho_c \times X_i \times 0.001$$

**Equation 360-43**

Where:

- $E_i$  = Annual EOR injection gas venting mass emissions at critical conditions  $c$  from blowdowns (tonnes/y).  
 $N$  = Number of blowdowns for the equipment in reporting year.  
 $V_v$  = Total physical volume of blowdown equipment chambers (including, but not limited to, pipelines, manifolds and vessels) between isolation valves (m<sup>3</sup>).  
 $\rho_c$  = Density of critical phase EOR injection gas (kg/m<sup>3</sup>). Use an appropriate standard method published by a consensus-based standards organization if such

a method exists or otherwise an industry standard to determine density of super critical EOR injection gas.

$X_i$  = Mass fraction of GHG<sub>i</sub> in critical phase injection gas.

0.001 = Conversion factor from kilograms to tonnes.

(u) Hydrocarbon liquids dissolved CO<sub>2</sub> from flashing [Reserved]

(v) Produced water dissolved CO<sub>2</sub> / Coal bed methane produced water emissions [Reserved]

(w) Field gas or process vent gas combustion. For combustion units that combust field gas or process vent gas or any blend of field gas and process vent gas, you must comply with following requirements:

(1) Measure the higher heating value of the field gas or process vent gas annually.

(i) Calculate the CO<sub>2</sub> and CH<sub>4</sub> emissions using either the Tier 3 or Tier 4 methodology in WCI.20 (General Stationary Combustion Sources). Sampling, analysis and measurement requirements (including for gas composition) required for WCI.360 in WCI.025(f) apply in place of those indicated for Equation 20-7, or

(ii) When measurement data is not available and if the measured higher heating value is equal to or greater than 36.3 MJ/m<sup>3</sup> and less than 40.98 MJ/m<sup>3</sup>, then calculate the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions using the methods in WCI.20 (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.

(2) Maintain the WCI.20 (General Stationary Combustion Sources) methodology, required by paragraph (1) of this section, for subsequent reporting years.

(x) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.363 must be calculated by methodologies consistent with those presented here, the 2009 API Compendium<sup>2</sup>, or other similar resource documents.

## § WCI.364 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision

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<sup>2</sup> American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

of appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

(a) Leak Detection

- (0.1) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein. A minimum of 12 months and a maximum of 36 months is allowed between surveys.
- (0.2) If there is no such legal requirement (as specified in paragraph (a)(0.1) of this section), then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(m), (n), and (o), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based on random or spot-sampling modeling, detection or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak is found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode.

- (1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:
- (i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument inspection described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
- (ii) Provide a date and time stamp for video records of every monitoring event.

- (2) Bubble tests
  - (3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the CAPP Best Management Practices for Fugitive Emissions
  - (4) Other methods as outlined in the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary provided that sufficient documentation as to the method used, test results, and the methods reliability, and accuracy is maintained and updated at regular intervals.
- (b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to an appropriate standard published by a consensus standards organization such as ASTM International, Canadian Standards Association (CSA), American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB) , If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), Canadian Gas Association (CGA) or American Petroleum Institute (API) may be used. If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.
- (c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed 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. If the bag inflates in less than one second, assume one second inflation time.
  - (2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.
  - (3) Correct the natural gas volumetric emissions to standard conditions using the calculations in WCI.363(q).
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).
- (d) Use a High-flow Sampler to measure emissions within the capacity of the instrument.

- (1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH<sub>4</sub> by using calibrated gas samples and by following manufacturer's instructions for calibration.
  - (2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, including, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
  - (3) If the High-flow Sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source, then anti-static wraps or other aids must be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).
- (e) Peng Robinson Equation of State means the equation of state defined by Equation 360-44 of this section.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad \text{Equation 360-44}$$

Where:

$p$  = Absolute pressure.  
 $R$  = Universal gas constant.  
 $T$  = Absolute temperature.  
 $V_m$  = Molar volume.

$$a = \frac{0.45724R^2T_c^2}{p_c}$$

$$b = \frac{0.7780RT_c}{p_c}$$

$$\alpha = \left( 1 + \left( 0.37464 + 1.54226\omega - 0.26992\omega^2 \right) \left( 1 - \sqrt{\frac{T}{T_c}} \right) \right)^2$$

Where:

$\omega$  = Acentric factor of the species.

$T_c$  = Critical temperature.  
 $P_c$  = Critical pressure.

(f) Onshore Production and Processing Storage Tanks.

- (1) A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location. Sampling protocol specific to the collection of separator liquid can be found in the following publications:
  - (i) Appendix C Sampling Protocol section (page 33) of the *E&P TANK Version 2.0 User's Manual*.
  - (ii) Wyoming Department of Environmental Quality Air Quality Division guidance document *Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas*.
  - (iii) Gas Processors Association (GPA) Standard 2174-93, *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography*.
- (2) The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.
- (3) Sampling and laboratory based determination of the gas to oil ratio GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions. Sampling shall be annual for oil production rates between 1.75 and 15.9 m<sup>3</sup>/day, semi-annual for oil production rates between 15.9 and 79.5 m<sup>3</sup>/day, and quarterly for oil production rates greater than 79.5 m<sup>3</sup>/day.
- (4) An additional sample shall be collected and analyzed if:
  - (i) The oil production rate at the storage tank battery changes more than 20 percent for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).
  - (ii) The separator operating pressures change by more than 10 percent.
- (5) The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of ±5%.

**§ WCI.365 Procedures for Estimating Missing Data**

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as

soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

### **§ WCI.366 Definitions**

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulphide (H<sub>2</sub>S) and carbon dioxide (CO<sub>2</sub>) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal (AGR) unit means a process unit that separates hydrogen sulphide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent stack emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Blowdown vent stack emissions mean natural gas and/or CO<sub>2</sub> released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to a emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO<sub>2</sub> by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO<sub>2</sub> from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO<sub>2</sub> 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 venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO<sub>2</sub>. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Coal bed methane (CBM) means natural gas which is extracted from underground coal deposits or "beds."

Component means 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 natural gas or CO<sub>2</sub> by drawing in low pressure natural gas or CO<sub>2</sub> and discharging significantly higher pressure natural gas or CO<sub>2</sub>.

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..

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO<sub>2</sub> 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 (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, pelletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process

fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Farm taps means pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

Field means the surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area;

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare, for the purposes of WCI.360, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

Fugitive emissions means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other.

Fugitive equipment leak means those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

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

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

High-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour .

Intermittent-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion

equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

LNG boiloff gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

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.

Offshore means seaward of the terrestrial borders of Canada, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of Canada.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals mean 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 emissions mean hydrocarbon 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 gas stream 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 the compressed gas stream that escapes to the atmosphere.

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

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue gas and residue gas compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

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

Sweet gas means natural gas with low concentrations of hydrogen sulphide (H<sub>2</sub>S) and/or carbon dioxide (CO<sub>2</sub>) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scrapper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackerhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

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.

Tubing diameter groupings are defined as follows: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Tubing systems mean piping equal to or less than one half inch diameter as per nominal pipe size

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Vapour 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.

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

Well completion means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps that may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop

open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (i.e. the well testing) through a choke (an orifice restriction). If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

Well workover means the process(es) of performing of one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, proppant and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

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. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapour 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".

## § WCI.367 Tables

### Directions for the use of Tables 360-1 to 360-2

- (a) Starting with 2014 calendar year emissions, for each component listed in the Tables 360-1 to 360-2 or otherwise required by the quantification method referencing Tables 360-1 and 360-2:
- (1) If statistically valid facility specific emission factors for a component type are available or can safely or reasonably developed, they must be used.
  - (2) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors, if they can be safely or reasonably developed.
  - (3) If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 360-1 to 360-2 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as booster stations used only sporadically during a year) may continue to use the default tables.
- (b) For 2011, 2012 and 2013 calendar year emissions:
- (1) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 360-1 to 360-2 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.
- (c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place
- (d) Any changes from facility-specific factors to company-specific or the defaults in Tables 360-1 to 360-2, or from company specific factors to the defaults in Tables 360-1 to 360-2 must be approved by the jurisdiction and substantiated by evidence that the new approach is more accurate for the facility or facilities in question.
- (e) If an emission factor required by the quantification method referencing Tables 360-1 and 360-2 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-1A or W-2 or the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004 may be used (as converted for use in the relevant equation).

- (f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request.
- (g) All emission factors or data collection for emission factors must be developed using CAPP (CAPP) or Canadian Gas Association (CGA) standard methods, or other methods if CAPP or CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.
- (h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

*The default emission factors provided in Tables 360-1 to 360-2 below are published emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.*

**Table 360-1. Additional Natural Gas Facility Average Emission Factors**

<b>Component – Service</b>	<b>Emission Factor, tonnes THC/component-hr</b>
Valves - fuel gas	2.81E-06
Valves - light liquid	3.52E-06
Valves - gas/vapor - all	2.46E-06
Valves - gas/vapor - sour	1.16E-06
Valves - gas/vapor - sweet	2.81E-06
Connectors - fuel gas	8.18E-07
Connectors - light liquid	5.51E-07
Connectors - gas/vapor - all	7.06E-07
Connectors - gas/vapor - sour	1.36E-07
Connectors - gas/vapor - sweet	8.18E-07
Control valves - fuel gas	1.62E-05
Control valves - light liquid	1.77E-05
Control valves - gas/vapor - all	1.46E-05
Control valves - gas/vapor - sour	9.64E-06
Control valves - gas/vapor - sweet	1.62E-05
Pressure relief valves - fuel gas and gas/vapor	1.70E-05
Pressure relief valves - light liquid	5.39E-06
Pressure regulators - fuel gas and gas/vapor	8.11E-06
Pressure regulators - gas/vapor - sour	4.72E-08

Pressure regulators - gas/vapor - sweet	8.39E-06
Open ended lines - fuel gas	4.67E-04
Open ended lines - light liquid	1.83E-05
Open ended lines - gas/vapor - all	4.27E-04
Open ended lines - gas/vapor - sour	1.89E-04
Open ended lines - gas/vapor - sweet	4.67E-04
Pump seals - light liquid	2.32E-05

Footnotes and Sources:

\* American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-21 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

**Table 360-2. Additional Oil Facility Average Emission Factors**

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas and gas/vapor	1.51E-06
Valves - heavy liquid	8.40E-09
Valves - light liquid	1.21E-06
Connectors - fuel gas and gas/vapor	2.46E-06
Connectors - heavy liquid	7.50E-09
Connectors - light liquid	1.90E-07
Control valves - fuel gas and gas/vapor	1.46E-05
Control valves - light liquid	1.75E-05
Pressure relief valves - fuel gas and gas/vapor	1.63E-05
Pressure relief valves - heavy liquid	3.20E-08
Pressure relief valves - light liquid	7.50E-05
Pressure regulators - fuel gas and gas/vapor	6.68E-06
Open ended lines - fuel gas and gas/vapor	3.08E-04
Open ended lines - light liquid	3.73E-06
Pump seals - heavy liquid	3.20E-08
Pump seals - light liquid	2.32E-05

Footnotes and Sources:

\* American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

### Directions for the use of Table 360-3

- (a) Major equipment listed in Tables 360-3 includes components located between the first flange of the process identified and the last flange before the next process.
- (b) When delineation between major equipment is not possible, individual component counts should be completed.

**Table 360-3. Default Major Equipment Component Counts for Canada**

(for further average component counts required by the methods in this quantification method, please refer to the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004, as updated from time to time.)

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
ABSORPTION (LEAN OIL)	Gas/Vapour	200	4	0	82	0	0	0	0
ABSORPTION (LEAN OIL)	Light Liquid	46	0	1	21	0	0	0	0
ADSORPTION	Gas/Vapour	243	8	0	63	0	0	0	0
ADSORPTION	Light Liquid	0	0	0	2	0	0	0	0
AERIAL COOLER	Gas/Vapour	2937	0	0	19	0	0	0	0
BULLET	Gas/Vapour	39	1	0	15	0	0	0	0
BULLET	Light Liquid	60	1	0	27	0	0	0	0
CENTRIFUGAL COMPRESSOR	Gas/Vapour	495	1	0	32	4	2	0	0
CENTRIFUGAL COMPRESSOR	Light Liquid	11	0	0	5	0	0	0	0
COLD BED ABSORPTION	Gas/Vapour	134	1	0	31	0	0	0	0
COLD BED ABSORPTION	Light Liquid	12	0	0	7	0	0	0	0
DE-BUTANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-BUTANIZER	Light Liquid	208	0	2	80	0	0	0	0
DEEP GAS WELL (>1000 M)	Gas/Vapour	19	0	0	6	0	0	0	0
DEEP GAS WELL (>1000 M)	Light Liquid	1	0	0	0	0	0	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Gas/Vapour	241	10	0	131	0	2	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Light Liquid	386	0	2	121	0	0	0	0
DE-ETHANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-ETHANIZER	Light Liquid	208	0	2	80	0	0	0	0
DE-PROPANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-PROPANIZER	Light Liquid	208	0	2	80	0	0	0	0
DESICCANT	Gas/Vapour	100	1	0	24	0	0	0	0
DESICCANT	Light Liquid	14	0	0	7	0	0	0	0
FLARE KNOCK OUT DRUM	Gas/Vapour	26	0	0	3	0	0	0	0
FLARE KNOCK OUT DRUM	Light Liquid	20	0	0	1	0	0	0	0
FLOW LINE HEADER TIE-IN	Gas/Vapour	0	0	0	0	1	0	0	0
FLOW LINE HEADER TIE-IN	Heavy Liquid	10	0	0	3	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
FLOW LINE HEADER TIE-IN	Light Liquid	10	0	0	3	0	0	0	0
FLOWING OIL WELL	Heavy Liquid	57	0	0	14	0	0	0	0
FLOWING OIL WELL	Light Liquid	57	0	0	14	0	0	0	0
FRACTIONATION	Gas/Vapour	241	10	0	131	0	0	0	0
FRACTIONATION	Light Liquid	386	0	2	121	0	0	0	0
GAS BOOT	Gas/Vapour	37	0	0	2	0	0	0	0
GAS BOOT	Light Liquid	40	0	0	2	0	0	0	0
GAS INJECTION WELL	Gas/Vapour	19	0	0	6	0	0	0	0
GAS LINE HEADER TIE-IN	Gas/Vapour	10	0	0	3	1	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Gas/Vapour	702	2	0	60	3	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Light Liquid	3	0	1	1	0	0	0	0
GAS SWEETENING: IRON SPONGE	Gas/Vapour	134	1	0	31	0	0	0	0
GAS SWEETENING: IRON SPONGE	Heavy Liquid	0	0	0	7	0	0	0	0
GAS SWEETENING: IRON SPONGE	Light Liquid	12	0	0	7	0	0	0	0
GAS-FIRED UNIT HEATER	Fuel Gas	10	0	0	1	0	0	0	0
GLYCOL DEHYDRATOR	Gas/Vapour	100	1	0	24	0	0	0	0
GLYCOL DEHYDRATOR	Light Liquid	14	0	0	7	0	0	0	0
GROUP TREATER	Gas/Vapour	178	0	0	21	1	0	0	0
GROUP TREATER	Heavy Liquid	56	0	0	17	1	0	0	0
GROUP TREATER	Light Liquid	56	0	0	17	1	0	0	0
HEAT EXCHANGER - GAS	Gas/Vapour	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Heavy Liquid	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Light Liquid	13	0	0	7	0	0	0	0
HEAVY OIL WELL - PRIMARY	Heavy Liquid	22	0	0	9	0	0	0	0
HEAVY OIL WELL - THERMAL	Heavy Liquid	22	0	0	9	0	0	0	0
INCINERATOR	Gas/Vapour	10	0	0	1	0	0	0	0
INLET SEPARATOR	Gas/Vapour	66	0	0	11	0	0	0	0
INLET SEPARATOR	Heavy Liquid	41	0	0	11	0	0	0	0
INLET SEPARATOR	Light Liquid	41	0	0	11	0	0	0	0
JOULE-THOMSON REFRIGERATION	Gas/Vapour	79	0	0	19	0	0	0	0
JOULE-THOMSON REFRIGERATION	Light Liquid	41	0	0	11	0	0	0	0
LINE HEATER	Fuel Gas	145	0	0	10	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
LINE HEATER	Gas/Vapour	40	1	0	10	0	0	0	0
METERING	Gas/Vapour	70	2	0	24	0	0	0	0
MOLECULAR SIEVE	Gas/Vapour	100	1	0	24	0	0	0	0
MOLECULAR SIEVE	Light Liquid	14	0	0	7	0	0	0	0
OIL PUMP	Heavy Liquid	10	0	1	3	0	0	0	0
OIL PUMP	Light Liquid	10	0	1	3	0	0	0	0
PIG TRAP	Gas/Vapour	11	0	0	3	0	0	0	0
PIPELINE HEADER	Gas/Vapour	0	0	0	0	1	0	0	0
PIPELINE HEADER	Heavy Liquid	10	0	0	3	0	0	0	0
PIPELINE HEADER	Light Liquid	10	0	0	3	0	0	0	0
POP TANK	Heavy Liquid	24	0	1	10	0	0	0	0
POP TANK	Light Liquid	24	0	1	10	0	0	0	0
PROCESS BOILER	Fuel Gas	25	0	0	2	0	0	0	0
PRODUCTION TANK	Gas/Vapour	2	0	0	1	0	0	0	0
PRODUCTION TANK	Heavy Liquid	24	0	1	0	0	0	0	0
PRODUCTION TANK	Light Liquid	24	0	1	0	0	0	0	0
PUMP JACK	Heavy Liquid	57	0	1	14	0	0	0	0
PUMP JACK	Light Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Heavy Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Light Liquid	57	0	1	14	0	0	0	0
RECIPROCATING COMPRESSOR	Fuel Gas	145	0	0	6	0	0	0	0
RECIPROCATING COMPRESSOR	Gas/Vapour	275	0	0	20	4	2	0	0
RECIPROCATING COMPRESSOR	Light Liquid	2	0	0	1	0	0	0	0
REFRIGERATION	Gas/Vapour	170	2	0	65	0	2	0	0
REFRIGERATION	Light Liquid	31	0	2	13	0	0	0	0
REGULATOR STATION	Gas/Vapour	24	0	0	10	0	0	0	0
SALT BATH HEATER	Fuel Gas	25	0	0	2	0	0	0	0
SCREW COMP CS TO FLARE	Gas/Vapour	228	2	0	35	0	0	1	2
SCREW COMPRESSOR	Gas/Vapour	228	2	0	35	0	1	1	2
SHALLOW GAS WELL (<1000 M)	Gas/Vapour	10	0	0	3	0	0	0	0
STABILIZATION	Gas/Vapour	80	3	0	20	0	0	0	0
STABILIZATION	Light Liquid	247	0	1	77	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
SULPHUR RECOVERY	Gas/Vapour	100	0	0	10	0	0	0	0
TAIL GAS CLEANUP	Gas/Vapour	25	0	0	5	0	0	0	0
TANK FARM	Heavy Liquid	190	0	6	94	0	0	0	0
TANK FARM	Light Liquid	190	0	6	94	0	0	0	0
TANK HEATER	Fuel Gas	10	0	0	2	0	0	0	0
TANK HEATER	Heavy Liquid	2	0	0	0	0	0	0	0
TANK HEATER	Light Liquid	2	0	0	0	0	0	0	0
TEST SEPARATOR	Gas/Vapour	49	1	0	15	0	0	0	0
TEST SEPARATOR	Heavy Liquid	25	0	0	15	0	0	0	0
TEST SEPARATOR	Light Liquid	25	0	0	15	0	0	0	0
TEST TREATER	Gas/Vapour	178	1	0	21	1	0	0	0
TEST TREATER	Heavy Liquid	56	0	0	17	0	0	0	0
TEST TREATER	Light Liquid	56	0	0	17	0	0	0	0
TURBO EXPANDER	Gas/Vapour	123	6	0	48	0	2	0	0
TURBO EXPANDER	Light Liquid	9	0	0	2	0	0	0	0
UNIT HEATER	Fuel Gas	10	0	0	2	0	0	0	0
UNIT HEATER	Light Liquid	2	0	0	0	0	0	0	0
UTILITY BOILER	Fuel Gas	25	0	0	2	0	0	0	0
VAPOUR RECOVERY COMPRESSOR	Gas/Vapour	25	0	0	5	0	1	0	0
VAPOUR RECOVERY COMPRESSOR	Light Liquid	2	0	0	3	0	0	0	0
WATER PUMP	Light Liquid	5	0	1	2	0	0	0	0

Footnotes and Sources:

\* Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004. Table 4.1,

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**TABLE 360-4 –DEFAULT GAS COMPOSITIONS FOR SPECIFIC FIELDS**

Table 360-4 is currently being developed and is likely to be incorporated in WCI.360 in the future. In the interim, please refer to default gas compositions for specific fields within the jurisdiction as posted by the regulator during or immediately after the reporting year.

**Table 360-5. Additional Natural Gas-driven Pneumatic Device Average Emission Factors**

<b>Pneumatic device type</b>	<b>Emission Factor, standard m<sup>3</sup>/hour/device</b>
High Continuous Bleed Pneumatic Device Vents	1.3620
Intermittent-bleed Pneumatic Device Vents	0.4927
Low Continuous Bleed Pneumatic Device Vents	0.0510
Pneumatic pumps	0.3766

Footnotes and Sources:

\* United States Environmental Protection Agency. *Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems* (40 CFR Part 98 Subpart W). September 2011. Table W-1A converted to metric units.

**Table 360-6. Average manufacturer bleed rates for pneumatic controllers, positioner, transmitters and transducers.**

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (Sm <sup>3</sup> /h) <sup>4</sup>
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (Sm <sup>3</sup> /h) <sup>4</sup>
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:

<sup>1</sup> Canadian Association of Petroleum Producers. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.

<sup>2</sup> United States Environmental Protection Agency. *Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Washington, DC. 2006. Appendix A converted to metric units.

<sup>3</sup> Various manufacturer specification publications.

<sup>4</sup> Factors equal to zero indicate that the device does not vent gas.

**Table 360-7. Nomenclature (subscripts, variables and their descriptions)**

<b>Variable Name</b>	<b>Description</b>
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance.
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 °C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
$\rho$	Variable - density
$\eta$	Variable – efficiency (fractional)