Addendum A: Greenhouse Gas Intensity Quantification Methodology

Guidance for Reporting within:

EO100™ Onshore Natural Gas and Light Oil Technical Supplement

and

EO100™ Natural Gas Gathering/Boosting and Processing Technical Supplement

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Table of Contents

List of Tables

Page

Glossary

boe – barrel of oil equivalent

Certifiable Unit – The scope of the assessment area including all facilities located within the predetermined geographical area. Facilities include well pads, compressor stations, gas processing plants, batteries, water treatment/storage facilities, and both active and inactive operations. Sometimes used interchangeably with Site.

Certified Unit - Subsequent to the Certifiable Unit achieving EO100™ certification it is called the Certified Unit. Sometimes used interchangeably with Site.

Condensate – Heavier hydrocarbons with low vapor pressure that condense and are in liquid form at the surface, generally C5+. Condensate is normally separated with crude oil from the remaining natural gas and natural gas liquids at the surface.

GHG – Greenhouse Gas emissions including but not limited to: CO_2, CH_4, N_2O

GOR – Gas to oil ratio. Volume of gas produced divided by the volume of oil produced (Unitless)

GWP – Global Warming Potential

HHV – Higher heating value in units of MJ/m^3

Natural Gas – Natural gas contains primarily methane but also contains natural gas liquids, carbon dioxide and water vapor. Rich-gas contains higher amounts of NGLS than dry-gas.

Natural Gas Liquids (NGLs) – Produced with natural gas from liquids rich reservoirs. NGLs include ethane, propane, butane, isobutane, pentane and pentanes plus. NGLs are processed into fractionated products at natural gas processing plants.

Oil – A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Liquids produced at natural gas processing plants are excluded. (EIA.gov)

Oil correction factor – Ratio of energy content in natural gas (including natural gas liquids) over the total energy content of the production or throughput

Scope 1 Emissions – Greenhouse gas emissions directly from combustion, venting or fugitive operations within the Certifiable Unit including any emissions from hauling within the Certifiable Unit.

Scope 2 Emissions – Greenhouse gas emissions associated with indirect imported electricity

1.0 BACKGROUND

With the urgency of climate change action needed, there is increasing interest from investors, natural gas buyers (utilities, distributors, LNG purchasers, hydrogen producers), and governments to be able to quantify the carbon intensity of entire supply chains of natural gas. Understanding and quantifying carbon intensity of upstream feedstock and supply chains are key to driving towards net zero global GHG emissions. EO is proposing to include a reporting metric of overall greenhouse gas intensity to enable differentiation of suppliers in the natural gas value chain and promote a positive influence to drive producers towards lower carbon intensity production. This would encourage operators to strive towards ultra-low GHG intensity and get recognition for achieving excellence.

2.0 KEY OBJECTIVES AND GOALS

The key objectives of this work are to:

- Enable quantification of the carbon intensity of the natural gas value chain.
- Provide an approach that is feasible without being overly complex.
    - Allowing for different methods for emissions quantification
    - Allowing for average parameters to be used rather than location specific if justifiable
    - Accounting for different energy contents of production to normalize intensity
- Provide a standardized approach whereby all Certified Units are reporting the same metrics.

One key consideration has been on whether Certified Units should or could be compared to each other using this methodology. The recommendation is that full supply chains be compared rather than individual segmentized units. This is important as there will be different supply chain pathways and comparing these pathways is the key to decarbonization. This will enable a buyer to make informed choices on the supply of their gas. This methodology is not meant to be used to compare one specific facility to another. For example, comparing one gas processing plant to another is not the intention of this work or recommended as a best practice as there are so many factors that can affect an individual plant's intensity such as level of compression required, liquids content, H_2S content, and formation CO_2 content. Furthermore, comparing a processing plant with compression done within a plant's boundaries and another processing plant where compression is done in the field prior to arrival at the plant, results in an unfair comparison as the plant without compression will have a much lower GHG intensity. These differences may be levelled out as many Certifiable Units contain multiple gas processing plants but nevertheless, it is *not* EO's recommendation to compare segmentized intensities of individual Certified Units to each other.

This methodology is ***not*** meant to:

- Be used to compare facility to facility or even site to site;
- Replace methane intensity quantification or be used to quantify the methane intensity of a site. It is recognized that the considerations such as allocating emissions between different types of equipment would be different when quantifying methane emissions compared to combustion emissions; or
- Replace jurisdictional reporting.

3.0 APPLICABILITY AND TIMEFRAME

This methodology is applicable to Certifiable Units that are predominately focussed on natural gas production and processing with a gas to oil ratio of 6000 scf/bbl (~170 m^3/bbl) or greater (EIA, 2019). The methodology contained herein is to calculate the overall greenhouse gas intensity of segments within the natural gas value chain. For certifiable units that are predominately producing oil, the greenhouse gas intensity should be reported in tCO_2e/boe. The certifiable unit does not contain non-operated facilities.

This methodology should be used to calculate the GHG intensity for reporting under Performance Targets 101.5.7.6, 101.5.7.12 and 101.5.7.17 under Objective 5.7 Greenhouse Gases within the EO100™ Standard Technical Supplement for Natural Gas and Light Oil Production and the EO100™ Technical Supplement for Natural Gas Gathering/Boosting and Processing.

All calculated GHG intensities should be based upon the full calendar year prior to the certification date or assessment. For example, if a certification is planned for August 2022, the GHG intensity should be calculated for the full calendar year of 2021 using emissions and production data consistent with that timeframe.

4.0 APPROACH

Greenhouse gas intensity is calculated in the units of gCO_2e/MJ (1 gCO_2e/MJ = 1.055 $kgCO_2e$/MMBtu) based upon higher heating value which is consistent with the reporting metrics of the California Low Carbon Fuel Standard (LCFS) and the Canadian Clean Fuel Standard (CFS). It is the intention that reporting intensity with commonly used lifecycle metrics will allow for better insight into value chain emissions and eventually allow for quantification of the carbon intensity of the entire natural gas value chain from well to end use. If gas can be traced from point of production to point of sale, the carbon intensities for the value chain segments can be added to produce an overall carbon intensity which is important insight into supply chain management to enable the rapid decarbonization of the global economy. For this quantification methodology, just the upstream to midstream segments of the value chain are considered.

Segments of the natural gas value chain that are included in this methodology are:

- Production
- Gathering and boosting
- Processing

Scope 1 and Scope 2 greenhouse gas emissions are included for each segment. As operators start to decarbonize their infrastructure, emissions associated with electricity imports will become more important especially when facilities are electrified. This quantification methodology document contains a methodology for estimating grid electricity consumption intensity and current estimated values for several US states and Canadian provinces. It is expected that the grid intensity values be updated annually to track the local grid decarbonization progress as well.

It is important to avoid double counting of throughput when one molecule of gas may pass through many different facilities. This methodology includes a proposal for treatment of throughput so that double counting can be avoided.

5.0 CERTIFIABLE UNIT EMISSIONS

EO considers Scope 1 (direct emissions) and Scope 2 (emissions associated with indirect electricity imports) to be included within the scope of reporting of the Certifiable Unit. In addition, emissions from drilling, hydraulic fracturing, and completions must be included as Scope 1 even if those emissions are from contractor operated equipment.

5.1 Emission Sources

5.1.1 Production Segment

A production facility is defined as all equipment located on a single well-pad or associated with a single well-pad including but not limited to flares, combustion equipment, storage tanks, engines and compressors, separators, heater/boilers, drilling and completions equipment, water treatment, water transport, portable generators, workover equipment, and pneumatic devices.

For the purposes of reporting GHG emissions and production volumes, all single well-pads within the area of certification (Certifiable Unit) are to be aggregated and reported in the production segment.

Table 1 lists the common sources of emissions within the production segment.

Table 1: Emission Sources Included in the Production Segment

Activity	Emission Source
Drilling and Completions	Combustion emissions associated with engines for drilling and hydraulic fracturing, combustion emissions associated with combustion of gas during completions, fugitive emissions and venting emissions. Emissions should be included even if from contractor operated sources.
Flares	Combustion emissions and incomplete combustion emissions of both produced gas and associated gas
Water delivery	Trucking and pipeline delivery emissions associated with engines and pumps if operated directly (Scope 1).
Maintenance	Flaring and venting emissions during shutdowns and blowdowns
Dehydrator Vents (Glycol and Desiccant)	Venting
Equipment Fugitive Leaks (valves, flanges, seals, open-ended lines)	Verified through leak detection and repair surveys as well as any monitoring reports
Liquids Unloading	Venting associated with liquids unloading
Pneumatic Device Vents (controllers, pumps)	Venting from chemical injection pumps and pneumatic controllers
Compressors (co-located at well pads)	Routine compressor seal venting, compressor engine combustion

Activity	Emission Source
GPU Heaters	Combustion emissions for space heating
Storage tanks	Vents, fugitive leaks
Emergency shutdowns	Pressure relief, blowdowns, compressor starts, venting and flaring
Electricity Import	Electricity source generation intensity (from local source or local grid)

5.1.2 Boosting and Gathering Segment

Emissions from the boosting and gathering segment should be reported for every activity that the segment contains. Some typical activities are listed in Table 2.

Table 2: Emission Sources Included in the Boosting and Gathering Segment

Activity	Emission Source
Maintenance	Flaring and venting emissions during shutdowns and blowdowns
Flares	Combustion emissions and incomplete combustion emissions of both produced gas and associated gas.
Compression	Compressor engines. Combustion emissions as well as vented emissions from seals
Dehydration	Glycol dehydrator vent stacks
Equipment Fugitive Leaks	Verified through leak detection and repair surveys as well as any monitoring reports

Activity	Emission Source
Pneumatic Device Vents (controllers, pumps)	Venting from chemical injection pumps and pneumatic controllers
Heaters	Combustion emissions from heaters
Storage tanks	Vents, fugitive leaks
Emergency shutdowns	Pressure relief, blowdowns, compressor starts, venting and flaring
Electricity Import	Electricity source generation intensity (from local source or local grid)

5.1.3 Processing Segment

Many natural gas operators in North America operate over multiple segments of the value chain. Some Certifiable Units include well production, gathering and boosting and gas processing segments while others may contain only one or two of these segments. Boundaries between the gathering and boosting segment and the gas processing segment are typically not clear.

Emissions from the processing segment should be reported for every activity that the segment contains. Some typical activities are listed in Table 3.

Table 3: Emission Sources Included in the Processing Segment

Activity	Emission Source
Maintenance	Flaring and venting emissions during shutdowns and blowdowns
Flares	Combustion emissions and incomplete combustion emissions of both produced gas and associated gas.
Combustion Units (miscellaneous)	Sweetening units, fractionation units, separators, stabilization units, coolers, heaters

Activity	Emission Source
Compression (located at processing facilities)	Compressor engines. Combustion emissions as well as vented emissions from seals
Dehydration	Glycol dehydrator vent stacks
Equipment Fugitive Leaks	Verified through leak detection and repair surveys as well as any monitoring reports
Pneumatic Device Vents (controllers, pumps)	Venting from chemical injection pumps and pneumatic controllers
Storage tanks	Vents, fugitive leaks
Emergency shutdowns	Pressure relief, blowdowns, compressor starts, venting and flaring
Electricity Import	Electricity source generation intensity (from local source or local grid)

5.2 Oil Correction Factor

To evaluate the natural gas supply chain greenhouse gas intensity, oil and condensate should be accounted for and emissions adjusted accordingly. Oil and condensate are not part of the natural gas value chain and so emissions should be adjusted for oil and condensate through an oil correction factor.

$$Oil\ Correction\ Factor = \frac{m^3_{Natural\ Gas} x\ HHV_{Natural\ Gas}}{m^3_{Natural\ Gas} x HHV_{Natural\ Gas} + m^3_{oil\ and\ condensate} x HHV_{Oil\ and\ condensate}}$$

Where,

$m^3_{Natural\ Gas}$ *is the volume of natural gas and natural gas liquids produced at the Certifiable Unit*

$m^3_{Oil\ and\ Condensate}$ *is the volume of oil and condensate produced at the Certifiable Unit*

$HHV_{Natural\ Gas}$ *is the higher heating value of natural gas (including NGLs) in* $\left(\frac{MJ}{m^3}\right)$

$HHV_{Oil\ and\ Condensate}$ *is the higher heating value of light oil and condensate in* $\left(\frac{MJ}{m^3}\right)$

5.3 Global Warming Potentials

Emissions should be disclosed per segment per GHG constituent (disclosure requirements specified in Table 5) and quantified by a recognized protocol such as GHG Protocol, Western Climate Initiative (WCI) Methodology or EPA Greenhouse Gas Reporting Program (GHGRP). To calculate total equivalent CO_2 emissions (tCO_2e), the IPCC AR5 100-year global warming potentials should be used. Table 4 contains the GWPs of the commonly reported greenhouse gas emissions in the oil and gas sector.

Table 4: Global Warming Potentials

Gas	Chemical Formula	IPCC AR5 100-year Time Horizon GWP
Carbon Dioxide	CO_2	1
Methane	CH_4	28
Nitrous Oxide	N_2O	265

5.4 Scope 2 Emissions

Any electricity imported into the Certifiable Unit must be accounted for as Scope 2 emissions. If the GHG intensity of local source electricity information is known, local emission factors may be used, provided supporting documentation is submitted. In absence of any specific local electricity GHG emission factor, Appendix B contains a summary of provincial and state grid GHG intensities that can be used as a default. The sources of these data are noted in the table. While the most recent numbers were extracted at the time of publication of this quantification methodology, grid intensities change with time and should be updated annually. As local electricity grids start to green, it will be important to obtain the most recent values to keep the GHG inventory current and show progress towards GHG intensity reductions.

$$Scope\ 2\ GHG\ Emissions = Net\ Electricity\ Imported\ x\ EF$$

Where,

$$Net\ Electricity\ Imported\ is\ in\ the\ units\ of\ MWh\ and\ accounts\ for\ any\ exports\ to\ the\ grid$$

$$EF \text{ is the electricity source GHG emission intensity in } \frac{tCO_2e}{MWh}$$

6.0 TOTAL ADJUSTED GHG EMISSIONS

Within the Certifiable Unit and segment of operation, the sum of all the scope 1 and scope 2 emissions should be added as a sum product of the emissions and oil correction factor for each source (i.e. for each well pad or aggregation of well pads).

Total emissions =

$$\sum_{i}^{\#\,Sources} (Scope\ 1\ Emissions + Scope\ 2\ Emissions)_i\ x\ Oil\ Correction\ Factor_i$$

If the oil correction factor is not expected to be very different between the different facilities included within the Certifiable Unit segment being quantified, it is acceptable to use an average oil correction factor for the entire Certifiable Unit or portions as appropriate.

7.0 PRODUCTION AND THROUGHPUT

7.1 Production Segment

The amount of natural gas and natural gas liquids produced at all wells should be summed, excluding condensate and oil produced. Production from each well pad or group of wells should be multiplied by the energy content of the gas or higher heating value. If the energy content is unknown, a default energy content for dry or rich gas is provided in Appendix A. It is permissible to use an average energy content for the entire Certifiable Unit if does not change much over the operations. Areas with significantly different energy contents should be summed separately.

Total natural gas production =

$$\sum_{i}^{\#\,Sources} ({m^3}_{NaturalGas})_i\ x\ HHV_i$$

Where,

$$m^3_{Natural\ Gas}\ \text{is the well production of natural gas and natural gas liquids}$$

$HHV\ is\ the\ higher\ heating\ value\ of\ the\ production\ in\ \frac{MJ}{m^3}$

$i\ is\ the\ well\ or\ group\ of\ wells\ as\ appropriate$

7.2 Boosting and Gathering Segment

The gas throughput should be summed as the throughput entering a compressor station. If any throughput travels through multiple compressors in series, care must be taken not to double count this volume. The throughput should be multiplied by the average energy content of the gas or higher heating value. If the energy content is unknown, a default energy content for rich or dry gas is provided in Appendix A.

Total natural gas throughput =

$$\sum_{i}^{\#\,Sources} ({m^3}_{NaturalGas})_i\ x\ HHV_i - \sum_{j}^{\#\,duplicates} ({m^3}_{NaturalGas})_j\ x\ HHV_j$$

Where,

$m^3_{Natural\ Gas}\ is\ the\ receipt\ of\ natural\ gas\ and\ natural\ gas\ liquids\ at\ the\ compressor\ station\ inlet$

$HHV\ is\ the\ higher\ heating\ value\ of\ the\ throughput\ in\ \frac{MJ}{m^3}$

$i\ is\ the\ compressor\ station$

$j\ is\ any\ source\ that\ throughput\ was\ counted\ twice$

$(ex. 2\ compressor\ stations\ in\ series)$

7.3 Processing Segment

The gas throughput should be summed as the receipts at each of the gas processing plants. If any throughput from one gas processing plant travels into another plant, duplication should be avoided and throughput should only be counted once. The throughput should be multiplied by the average energy content of the gas or higher heating value. If the energy content is unknown, a default energy content for rich or dry gas is provided in Appendix A.

Total natural gas throughput =

$$\sum_{i}^{\#\,Sources} (m^3{}_{NaturalGas})_i \; x \; HHV_i - \sum_{j}^{\#\,duplicates} (m^3{}_{NaturalGas})_j \; x \; HHV_j$$

Where,

$m^3_{Natural\ Gas}$ *is the receipt at the gas plant*

HHV *is the higher heating value of the throughput in* $\frac{MJ}{m^3}$

i *is the gas plant*

j *is any source that throughput was counted twice*

$(ex.\ disposition\ from\ one\ gas\ processing\ plant\ that\ flows\ to\ another\ gas\ processing\ plant)$

8.0 CARBON INTENSITY CALCULATION

8.1 Production Segment

$$\boldsymbol{CI_{Production} = \frac{Total\ Emissions}{Total\ Production}}$$

8.2 Boosting and Gathering Segment

$$\boldsymbol{CI_{Boosting/Gathering} = \frac{Total\ Emissions}{Total\ Throughput}}$$

8.3 Processing Segment

$$\boldsymbol{CI_{Processing} = \frac{Total\ Emissions}{Total\ Throughput}}$$

9.0 DISCLOSURE AND REPORTING REQUIREMENTS

Table 5 contains the data that should be disclosed to the assessment body to be verified during the EO100™ certification assessment and annual follow-up re-verification assessments.

Table 5: Data to be Disclosed and Reported at the Certifiable/Certified Unit Level

Disclosure Element	Units
Scope 1 Emissions: Report all GHG emissions by constituent (i.e. CO_2, CH_4, N_2O etc.)	tCO_2e total and per constituent
Scope 2 Emissions: Net electricity imported	MWh
Scope 2 Emissions: Electricity Consumption Intensity	tCO_2e/MWh
Production: Report total natural gas, oil and condensate production	m^3 condensate, m^3 oil, e^3m^3 natural gas
Throughput: Report throughput of natural gas, oil and condensate for boosting/gathering and processing segment	m^3 condensate, m^3 oil, e^3m^3 natural gas
Energy Content of Natural Gas Produced (HHV): If gas analysis has been done at the site level, otherwise default values provided may be used.	MJ/m^3
GHG Intensity/Carbon Intensity per segment: 1. Production 2. Boosting and Gathering and 3. Processing	gCO_2e/MJ

10.0 REFERENCES

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APPENDIX A: DEFAULT NATURAL GAS HEATING VALUES

Table A: Default Higher Heating Values

Category	Default Higher Heating Value (MJ/m^3)	Default Higher Heating Value (MMBtu/mcf)	Default Composition (vol%)
Default Rich Natural Gas[1]	44.77	1.202	80%CH_4 15% C_2H_6 5% C_3H_8
Default Dry Natural Gas[1]	38.25	1.143	98% CH_4 1% C_2H_6 0.3% C_3H_8 0.1%C_4H_{10} 0.3%CO_2 0.3% N_2
Default Oil and Condensate[2]	38,500	1,034	Crude Oil 84.8wt.% C, 873.5 kg/m^3 density

[1] AEP 2021. Table 15-2.

[2] API 2009. Table 3-8. Densities, Higher Heating Values, and Carbon Contents for Various Fuels.

APPENDIX B: DEFAULT GRID ELECTRICITY CONSUMPTION INTENSITIES

Table B contains estimated grid intensity values with the data sources for each. These values can be used as default if the local electricity source intensity is not known. The values should be updated annually as information comes available. It is expected that as local grids decarbonize further, electricity intensities should decrease with time.

Table B: Default Electricity Grid Consumption Intensities by Province and State

Location	Default Grid Consumption Intensity ($kgCO_2e/MWh$)	Data Source
Alberta	640	Canada's NIR – Part 3 (NIR, 2021) 2020 GHG consumption intensity
British Columbia – Integrated Grid	9.7	2021 Published Electricity GHG Emissions Intensity (BC CAS, 2022)
BC – Fort Nelson Grid	511	2021 Published Electricity GHG Emissions Intensity (BC CAS, 2022)
Saskatchewan	620	Canada's NIR – Part 3 (NIR, 2021) 2020 GHG consumption intensity
West Virginia	874	Calculated from EIA 2020 State electricity generation emissions (all sources) (EIA, 2021a) and EIA 2020 state net electricity generation (total electric power generation) (EIA, 2021b).
Pennsylvania	314	
Texas	428	
Louisiana	441	
Colorado	537	
Oklahoma	314	
Ohio	556	

Appendix C: Conversion Factors

Table C-1: Unit Definitions

Unit	Definition
scf	Standard cubic feet (@14.7psi, 60 deg. F). When written as "cf" assume standard conditions
sm^3	Standard cubic metre (@101.325kPa, 15 deg. C). When written as m^3, assume standard conditions.
bbl	barrel
mcf	Thousand cubic feet
mmcf	Million cubic feet
e^3m^3	Thousand cubic metres
MJ	megajoule
MMBtu	Million British thermal units
MWh	Megawatt - hour
t	Metric tonnes
tCO_2e	Metric tonnes of carbon dioxide equivalent (with constituents converted to CO_2e by their respective GWPs)
$kgCO_2e$	Kilogram of carbon dioxide equivalent
gCO_2e	Gram of carbon dioxide equivalent

Table C-2: Unit Conversion Factors

Source Unit	Equals
1 MMBtu	**1055 MJ**
1 m	**3.28 ft**
1 m^3	**35.3 ft^3**
1 m^3	**1000 L**
1 m^3	**6.2898 bbl**

APPENDIX D: EXAMPLE CALCULATIONS

Example 1: GHG Intensity Calculation for Production Segment (Canadian Example)

Certifiable Unit Contains:

Three separate areas are defined since they have different parameters such as energy content and oil:gas production. These areas may contain any number of wells or well pads and associated infrastructure.

Area 1	Area 2	Area 3
Scope 1 emissions = 4000 tCO_2e Gas Produced = 50,000 e^3m^3 Oil and Condensate Produced = 0 HHV_{gas} = 38 MJ/m^3	Scope 1 emissions = 15,000 tCO_2e Gas Produced = 80,000 e^3m^3 Oil and Condensate Produced = 10,000 m^3 HHV_{gas} = 41 MJ/m^3 HHV_{oil} = 38,500 MJ/m^3	Scope 1 emissions = 40,000 tCO_2e Grid electricity imported = 20,000 MWh Jurisdiction = Alberta, Canada Gas Produced = 150,000 e^3m^3 Oil and Condensate Produced = 1,500 m^3 HHV_{gas} = 40 MJ/m^3 HHV_{oil} = 40,000 MJ/m3

Calculation of GHG Intensity: Production Segment:

Oil Correction Factor

$$Oil\ Correction\ Factor = \frac{m^3_{Natural\ Gas} x\ HHV_{Natural\ Gas}}{m^3_{Natural\ Gas} x HHV_{Natural\ Gas} +\ m^3_{oil\ and\ condensate} x HHV_{Oil\ and\ condensate}}$$

$$Oil\ Correction\ Factor\ Area\ 1 = 1$$

$$Oil\ Correction\ Factor\ Area\ 2 = \frac{80{,}000{,}000\ m^3 x\ 41\ MJ/m^3}{80{,}000{,}000\ m^3 x\ 41\ MJ/m^3 + 10{,}000\ m^3 x\ 38{,}500\ MJ/m^3} = 0.89$$

$$Oil\ Correction\ Factor\ Area\ 3 = \frac{150{,}000{,}000\ m^3 x\ 40\ MJ/m^3}{150{,}000{,}000\ m^3 x\ 40\ MJ/m^3 + 1{,}500\ m^3 x\ 40{,}000\ MJ/m^3} = 0.99$$

__Emissions__

Scope 2 emissions Area 3 = 20,000 MWh x 0.64tCO_2e/MWh (default Alberta grid used) = 12,800 tCO_2e

Total Emissions =

$$\sum_{i}^{\#\ Sources} (Scope\ 1\ Emissions + Scope\ 2\ Emissions)_i\ xOil\ Correction\ Factor_i$$

$$Total\ Emissions = 4{,}000tCO2e\ x\ 1 + 15{,}000tCO2e\ x\ 0.89 + (40{,}000 + 12{,}800)tCO2e\ x\ 0.99$$
$$= 71{,}272\ tCO2e$$

__Production__

Total Production =

$$\sum_{i}^{\#\ Sources} (m^3{}_{NaturalGas})_i\ x\ HHV_i$$

$$Total\ Production = 50{,}000{,}000m3\ x \frac{38MJ}{m3} + 80{,}000{,}000m3\ x \frac{41MJ}{m3} + 150{,}000{,}000m3\ x \frac{40MJ}{m3}$$
$$= 11{,}180{,}000{,}000\ MJ$$

__Intensity__

$$GHG\ Intensity = \frac{71{,}272\ tCO2e\ x\ 1{,}000{,}000\ gCO2e/tCO2e}{11{,}180{,}000{,}000\ MJ}$$

__= 6.4 gCO_2e/MJ__

Example 2: GHG Intensity Calculation for Production Segment (US Example)

Certifiable Unit Contains:

Area 1
Scope 1 emissions = 4000 tCO_2e
Gas Produced = 1,765,500 mcf
Oil and Condensate Produced = 0
HHV_{gas} = 1.02MMBtu/mcf

Area 2
Scope 1 emissions = 15,000 tCO_2e
Gas Produced = 2,824,800 mcf
Oil and Condensate Produced = 353.1 mcf
HHV_{gas} = 1.1 MMBtu/mcf
HHV_{oil} = 1033.5 MMBtu/mcf

Area 3
Scope 1 emissions = 40,000 tCO_2e
Grid electricity imported = 20,000 MWh
Jurisdiction = Pennsylvania, USA
Gas Produced = 5,296,500 mcf
Oil and Condensate Produced = 52.97 mcf
HHV_{gas} = 1.07 MMBtu/mcf
HHV_{oil} = 1074 MMBtu/mcf

Calculation of GHG Intensity: Production Segment:

Gas Ratio

$$Oil\ Correction\ Factor = \frac{mcf_{Natural\ Gas} x\ HHV_{Natural\ Gas}}{mcf_{Natural\ Gas} x HHV_{Natural\ Gas} + mcf_{Oil\ and\ Condensate} x HHV_{Oil\ and\ Condensate}}$$

$$Oil\ Correction\ Factor\ Area\ 1 = 1$$

$$Oil\ Correction\ Factor\ Area\ 2 = \frac{2{,}824{,}800\ mcf x\ 1.1\ MMBtu/mcf}{2{,}824{,}800\ mcf\ x\ 1.1\ MMBtu/mcf + 353.1\ mcf x\ 1033.5\ MMBtu/mcf}$$
$$= 0.89$$

$$Oil\ Correction\ Factor\ Area\ 3 = \frac{5{,}296{,}500\ mcf x\ 1.07\ MMBtu/mcf}{5{,}296{,}500\ mcf x\ 1.07 \frac{MMBtu}{mcf} + 52.97 mcf x\ 1074\ MMBtu/mcf} = 0.99$$

__Emissions__

Scope 2 emissions Pad 3 = 20,000 MWh x 0.314 tCO_2e/MWh (Grid intensity from Table B for Pennsylvania used) = 6,280 tCO_2e

Total Emissions =

$$\sum_{i}^{\#\,Sources} (Scope\ 1\ Emissions + Scope\ 2\ Emissions)_i\ x\ Oil\ Correction\ Factor_i$$

$$Total\ Emissions = 4{,}000 tCO2e\ x\ 1 + 15{,}000 tCO2e\ x\ 0.89 + (40{,}000 + 6{,}280) tCO2e\ x\ 0.99$$
$$= 64{,}817 tCO2e$$

__Production__

Total Production =

$$\sum_{i}^{\#\,Sources} (mcf_{NaturalGas})_i\ x\ HHV_i$$

$$Total\ Production$$

$$= 1{,}765{,}500\ mcf\ x\ \frac{1.02\ MMBtu}{mcf} + 2{,}824{,}800\ mcf\ x\ \frac{1.1\ MMBtu}{mcf} + 5{,}296{,}500\ mcf\ x\ \frac{1.07 MMBtu}{mcf}$$

$$= 10{,}575{,}345\ MMBtu$$

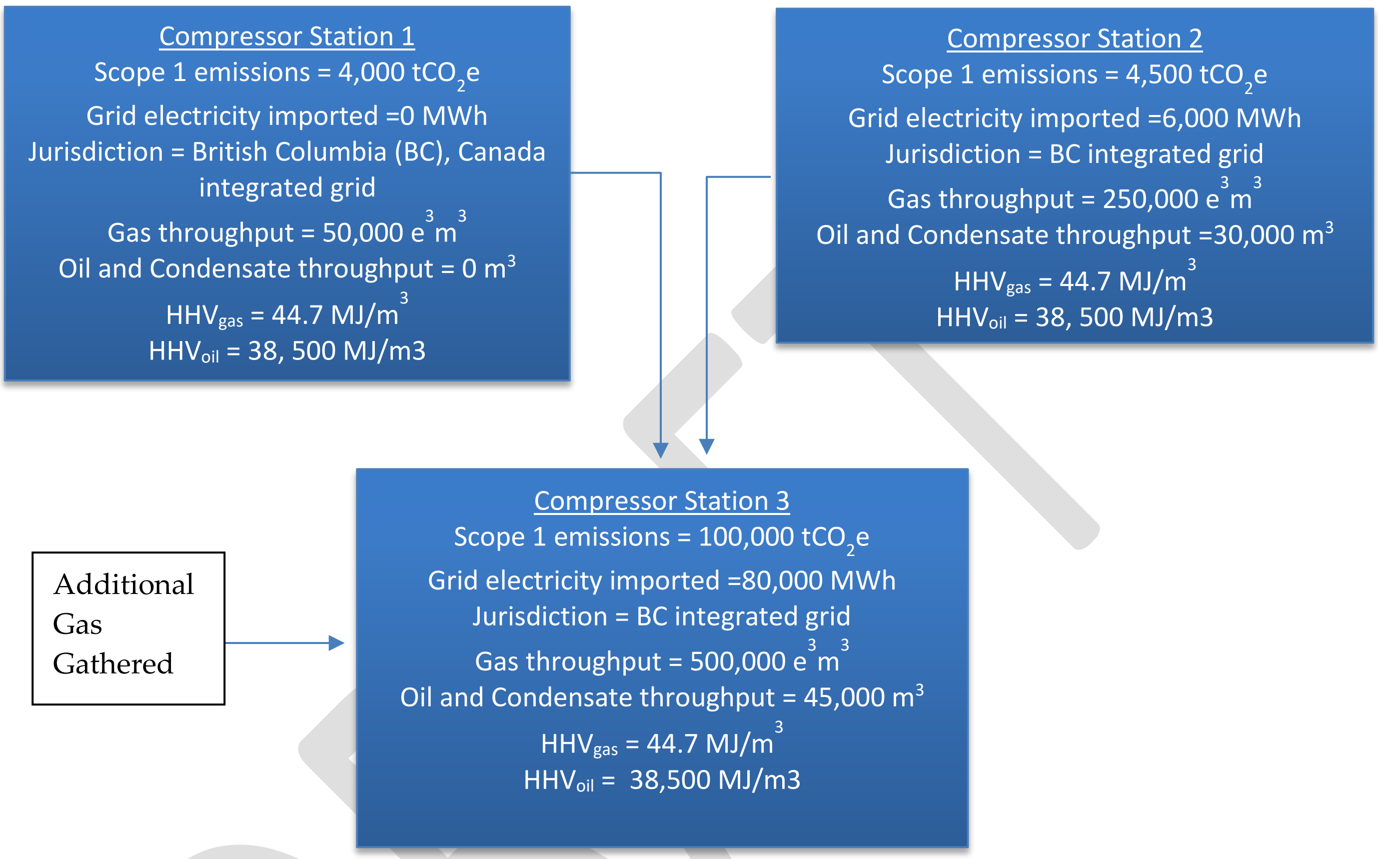
__Intensity__

$$GHG\ Intensity = \frac{64{,}817 tCO2e\ x\ 1{,}000\ kgCO2e/tCO2e}{10{,}575{,}345\ MMbtu}$$

__= 6.13 $kgCO_2e$/MMBtu__

Example 3: GHG Intensity Calculation for Gathering and Boosting Segment (Canadian Example)

Certifiable Unit Contains:



Calculation of GHG Intensity: Gathering and Boosting Segment:

Oil Correction Factor

$$Oil\ Correction\ Factor = \frac{m^3_{Natural\ Gas} x\ HHV_{Natural\ Gas}}{m^3_{Natural\ Gas} xHHV_{Natural\ Gas} +\ m^3_{oil\ and\ condensate} xHHV_{Oil\ and\ condensate}}$$

$$Oil\ Correction\ Factor\ Compressor\ Station\ 1 = 1$$

$$Oil\ Correction\ Factor\ Compressor\ Station\ 2 = \frac{250{,}000{,}000\ m^3 x\ 44.7\ MJ/m^3}{250{,}000{,}000\ m^3 x\ 44.7\ MJ/m^3 + 30{,}000\ m^3 x\ 38{,}500\ MJ/m^3} = 0.91$$

$$Oil\ Correction\ Factor\ Compression\ Station\ 3 = \frac{500{,}000{,}000\ m^3 x\ 44.7\ MJ/m^3}{500{,}000{,}000\ m^3 x\ 44.7\ MJ/m^3 + 45{,}000\ m^3 x\ 38{,}500\ MJ/m^3} = 0.93$$

Emissions

Scope 2 emissions Compressor Station 2 = 6,000 MWh x 0.0097tCO_2e/MWh (default BC integrated grid used) = 58 tCO_2e

Scope 2 emissions Compressor Station 3 = 80,000 MWh x 0.0097tCO_2e/MWh (default BC integrated grid used) = 776 tCO_2e

Total Emissions =

$$\sum_{i}^{\#\ Sources} (Scope\ 1\ Emissions + Scope\ 2\ Emissions)_i\ x\ Oil\ Correction\ Factor_i$$

$$Total\ Emissions = 4{,}000 tCO2e\ x\ 1 + (4{,}500 + 58) tCO2e\ x\ 0.91 + (100{,}000 + 776) tCO2e\ x\ 0.93 = 101{,}869\ tCO2e$$

Throughput

Total Throughput =

$$\sum_{i}^{\#\ Sources} (m^3{}_{NaturalGas})_i\ x\ HHV_i - \sum_{j}^{\#\ duplicates} (m^3{}_{NaturalGas})_j\ x\ HHV_j$$

$$Total\ Throughput = 500{,}000{,}000m3\ x \frac{44.7MJ}{m3} = 22{,}350{,}000{,}000\ MJ$$

Note that only the throughput through compressor station 3 should be counted as throughout from compressor stations 1 and 2 both flow into compressor station 3.

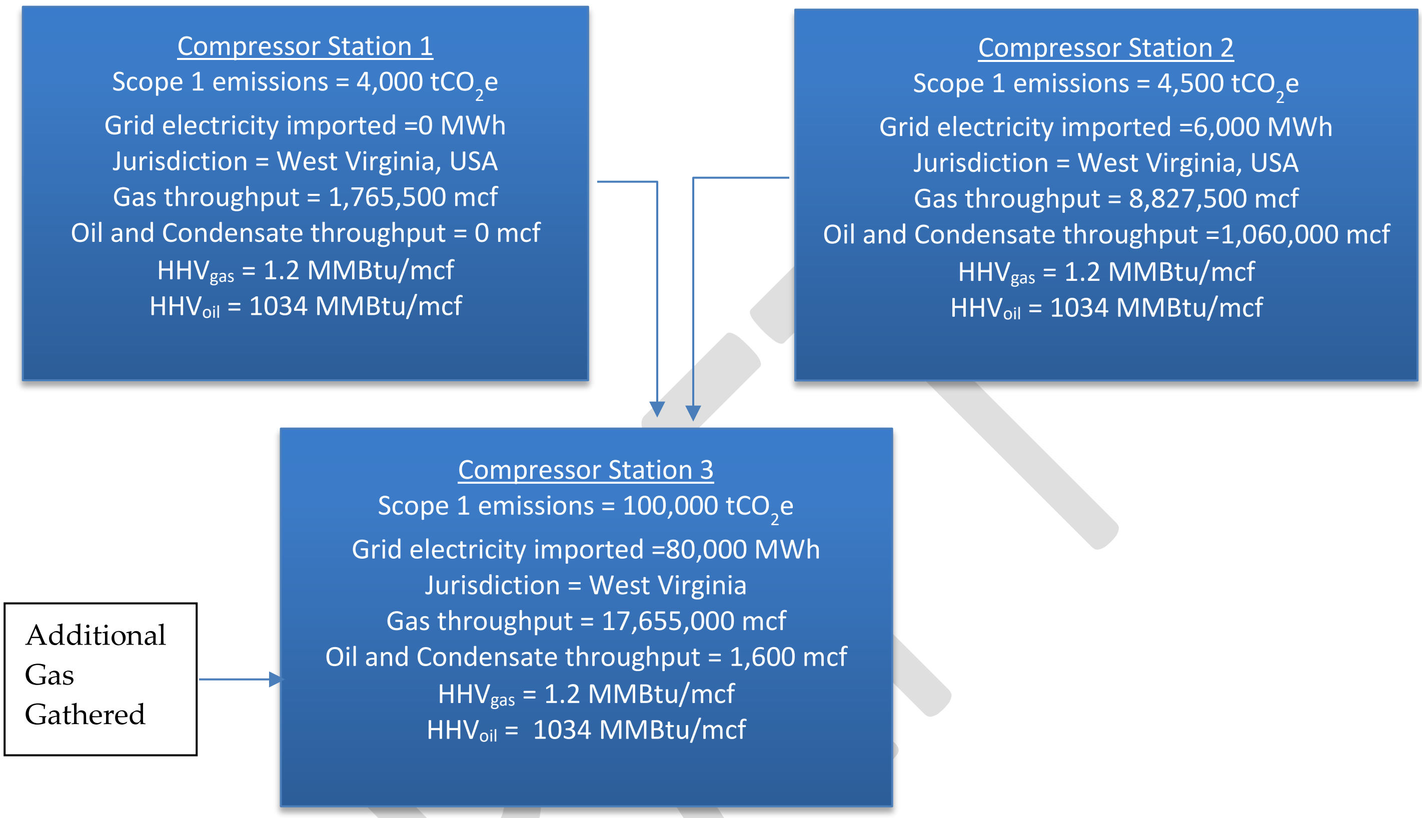
Intensity

$$GHG\ Intensity = \frac{101{,}869\ tCO2e\ x\ 1{,}000{,}000\ gCO2e/tCO2e}{22{,}350{,}000{,}000\ MJ}$$

= 4.6 gCO_2e/MJ

<u>Example 4: GHG Intensity Calculation for Compression and Processing Segment (US Example)</u>

Certifiable Unit Contains:



<u>Calculation of GHG Intensity: Compression and Processing Segment:</u>

<u>Oil Correction Factor</u>

$$Oil\ Correction\ Factor = \frac{mcf_{Natural\ Gas}\ x\ HHV_{Natural\ Gas}}{mcf_{Natural\ Gas}\ xHHV_{Natural\ Gas} + mcf_{Oil\ and\ condensate}\ xHHV_{Oil\ and\ condensate}}$$

$$Oil\ Correction\ Factor\ Compressor\ Station\ 1 = 1$$

$$Oil\ Correction\ Factor\ Compressor\ Station\ 2 = \frac{8{,}827{,}500\ mcf x\ 1.2\ MMBtu/mcf}{8{,}827{,}500\ mcf\ x\ 1.2\frac{MMBtu}{mcf} + 1{,}060 mcf\ x\ 1034\ \frac{MMBtu}{mcf}} = 0.91$$

$$Oil\ Correction\ Factor\ Compressor\ Staion\ 3 = \frac{17{,}655{,}000\ mcf x\ 1.2\ MMBtu/mcf}{17{,}655{,}000\ mcf\ x\ 1.2\frac{MMBtu}{mcf} + 1{,}600 mcf\ x\ 1034\frac{MMBtu}{mcf}} = 0.93$$

__Emissions__

Scope 2 emissions Compressor Station 2 = 6,000 MWh x 0.874 tCO_2e/MWh (Table B: West Virginia) = 5,244 tCO_2e

Scope 2 emissions Processing Plant = 80,000 MWh x 0.874 tCO_2e/MWh (Table B: West Virginia) = 69,920 tCO_2e

Total Emissions =

$$\sum_{i}^{\#\ Sources} (Scope\ 1\ Emissions + Scope\ 2\ Emissions)_i\ x\ Oil\ Correction\ Factor_i$$

$$Total\ Emissions = \ 4{,}000 tCO2e\ x\ 1 + (4{,}500 + 5{,}244) tCO2e\ x\ 0.91 + (100{,}000 + 69{,}920) tCO2e\ x\ 0.93 = 170{,}893\ tCO2e$$

__Throughput__

Total Throughput =

$$\sum_{i}^{\#\ Sources} (mcf_{NaturalGas})_i\ x\ HHV_i - \sum_{j}^{\#\ duplicates} (mcf_{NaturalGas})_j\ x\ HHV_j$$

$$Total\ Throughput = 17{,}655{,}000\ mcf\ x1.2 \frac{MMBtu}{mcf} = 21{,}186{,}000\ MMBtu$$

Since all gas flows through compressor station 3, the total throughput is that of compressor station 3.

Intensity

$$GHG\ Intensity = \frac{170{,}893\ tCO2e\ x\ 1{,}000\ kgCO2e/tCO2e}{21{,}186{,}000\ MMBtu}$$

= 8.1 $kgCO_2e/MMBtu$