Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling

Supporting Information

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S.1 Canadian Public Data Reporting structure and Data

Table 1 presents all the emission categories in B.C. that must be reported to the provincial government should a facility emit above the threshold of 10,000 tCO_2e/MJ. If a facility emits below this threshold, they can voluntarily report should they wish, but it is not required. The full description of reporting requirements of GHG emissions is listed in BC's Greenhouse Gas Emissions Reporting Regulation document [1]. The disaggregation of reporting is detailed in BC's requirements, but the level of detail from their reporting structure is not seen in the publicly available data summarized in Table S1.

Table S1 - Reporting Requirements for BC Oil and Gas Production and LNG activities

Item	Activity	Source Type	Greenhouse Gas Type	Relevant Requirements
1	General stationary combustion at an operation or facility that carries out an activity listed in this column	(a) General stationary combustion of fuel or waste at a linear facilities operation resulting in the production of useful energy	Carbon Dioxide from non-biomass, Carbon Dioxide from biomass not listed in Schedule C, Methane, Nitrous Oxide	WCI.0202
		(b) General stationary combustion of fuel or waste at a linear facilities operation not resulting in the production of useful energy	Carbon Dioxide from non-biomass, Carbon Dioxide from biomass not listed in Schedule C, Methane, Nitrous Oxide	
		(c) Field gas or process vent gas combustion at a linear facilities operation	Carbon Dioxide from non-biomass, Carbon Dioxide from biomass not listed in Schedule C, Methane, Nitrous Oxide	WCI.360
		(d) General stationary combustion of fuel or waste at a linear facilities operation resulting in the production of useful energy	Carbon Dioxide from non-biomass, Carbon Dioxide from biomass not listed in Schedule C, Methane, Nitrous Oxide	WCI.0202
		(e) General stationary combustion of fuel or waste at a linear facilities operation not resulting in the production of useful energy	Carbon Dioxide from biomass listed in Schedule C	
2	Oil and gas extraction and gas processing activities, carbon dioxide transportation and oil transmission	(a) Natural gas pneumatic high bleed device venting	Carbon Dioxide from non-biomass, Methane	WCI.360
		(b) Natural gas pneumatic pump venting	Carbon Dioxide from non-biomass, Methane	
		(c) Natural gas pneumatic low bleed device venting	Carbon Dioxide from non-biomass, Methane	
		(d) Natural gas pneumatic intermittent bleed device venting	Carbon Dioxide from non-biomass, Methane	
		(e) Acid gas removal venting or incineration	Carbon Dioxide from non-biomass	
		(f) Dehydrator venting	Carbon Dioxide from non-biomass, Methane	
		(g) Well venting for liquids unloading	Carbon Dioxide from non-biomass, Methane	
		(h) Gas well venting during well completions and workovers with or without hydraulic fracturing	Carbon Dioxide from non-biomass, Methane	
		(i) Blowdown venting	Carbon Dioxide from non-biomass, Methane	
		(j) Onshore production and processing and storage tank releases	Carbon Dioxide from non-biomass, Methane	
		(k) Well testing venting and flaring	Carbon Dioxide from non-biomass, Methane, Nitrous Oxide	
		(l) Associated gas venting and flaring	Carbon Dioxide from non-biomass, Methane, Nitrous Oxide	
		(m) Flaring stacks	Carbon Dioxide from non-biomass, Methane, Nitrous Oxide	
		(n) Centrifugal compressor venting	Carbon Dioxide from non-biomass, Methane	
		(o) Reciprocating compressor venting	Carbon Dioxide from non-biomass, Methane	

		(p) Equipment leaks detected using leak detection and leaker emission factor methods	Carbon Dioxide from non-biomass, Methane	
		(q) Population count sources	Carbon Dioxide from non-biomass, Methane	
		(r) Transmission storage tanks	Carbon Dioxide from non-biomass, Methane	
		(s) Enhanced oil recovery injection pump blowdowns	Carbon Dioxide from non-biomass	
		(t) Produced water dissolved carbon dioxide and methane	Carbon Dioxide from non-biomass, Methane	
		(u) Enhanced oil recovery hydrocarbon liquids dissolved carbon dioxide	Carbon Dioxide from non-biomass	
		(v) Other venting sources	Carbon Dioxide from non-biomass, Methane	
		(w) Other fugitive sources	Carbon Dioxide from non-biomass, Methane	
		(x) Third-party line hits with release of gas	Carbon Dioxide from non-biomass, Methane	
3	Electricity transmission	Installation, maintenance, operation and decommissioning of electrical equipment	Sulphur Hexafluoride, Perfluorocarbons	WCI.230
4	Natural gas transmission, natural gas distribution or natural gas storage	(a) Natural gas pneumatic high bleed device venting	Carbon Dioxide from non-biomass, Methane	WCI.350
		(b) Natural gas pneumatic pump venting	Carbon Dioxide from non-biomass, Methane	
		(c) Natural gas pneumatic low bleed device venting	Carbon Dioxide from non-biomass, Methane	
		(d) Natural gas pneumatic intermittent bleed device venting	Carbon Dioxide from non-biomass, Methane	
		(e) Blowdown venting	Carbon Dioxide from non-biomass, Methane	
		(f) Flare stacks	Carbon Dioxide from non-biomass, Methane, Nitrous Oxide	
		(g) Centrifugal compressor venting	Carbon Dioxide from non-biomass, Methane	
		(h) Reciprocating compressor venting	Carbon Dioxide from non-biomass, Methane	
		(i) Equipment leaks detected using leak detection and leaker emission factor methods	Carbon Dioxide from non-biomass, Methane	
		(j) Population count sources	Carbon Dioxide from non-biomass, Methane	
		(k) Transmission storage tanks	Carbon Dioxide from non-biomass, Methane	
		(l) Other venting sources	Carbon Dioxide from non-biomass, Methane	
		(m) Other fugitive sources	Carbon Dioxide from non-biomass, Methane	
		(n) Third-party line hits with release of gas	Carbon Dioxide from non-biomass, Methane	
5	LNG activities	(a) Natural gas pneumatic high bleed device venting	Carbon Dioxide from non-biomass, Methane	WCI.350
		(b) Natural gas pneumatic pump venting	Carbon Dioxide from non-biomass, Methane	
		(c) Natural gas pneumatic low bleed device venting	Carbon Dioxide from non-biomass, Methane	
		(d) Natural gas pneumatic intermittent bleed device	Carbon Dioxide from non-biomass, Methane	
		(e) Acid gas removal venting or incineration	Carbon Dioxide from non-biomass	WCI.360
		(f) Dehydrator venting	Carbon Dioxide from non-biomass, Methane	
		(g) Blowdown venting	Carbon Dioxide from non-biomass, Methane	WCI.350
		(h) Onshore production and processing storage tank releases	Carbon Dioxide from non-biomass, Methane	WCI.360
		(i) Flare stacks	Carbon Dioxide from non-biomass, Methane, Nitrous Oxide	WCI.350
		(j) Centrifugal compressor venting	Carbon Dioxide from non-biomass, Methane	
		(k) Reciprocating compressor venting	Carbon Dioxide from non-biomass, Methane	
		(l) Equipment leaks detected using leak detection and leaker emission factor methods	Carbon Dioxide from non-biomass, Methane	

		(m) Population count sources	Carbon Dioxide from non-biomass, Methane	
		(n) Transmission storage tanks	Carbon Dioxide from non-biomass, Methane	
		(o) Enhanced oil recovery injection pump blowdowns	Carbon Dioxide from non-biomass	WCI.360
		(p) Produced water dissolved carbon dioxide and methane	Carbon Dioxide from non-biomass, Methane	
		(q) Enhanced oil recovery hydrocarbon liquids dissolved carbon dioxide	Carbon Dioxide from non-biomass	
		(r) Other venting sources	Carbon Dioxide from non-biomass, Biomass	WCI.350
		(s) Other fugitive sources	Carbon Dioxide from non-biomass, Methane	
		(t) Third party line hits with release of gas	Carbon Dioxide from non-biomass, Methane	
		(p) Produced water dissolved carbon dioxide and methane	Carbon Dioxide from non-biomass, Methane	

Table S2 - Public Data Availability from BC Government

Data Available from BC Government	
Category	**GHG Emissions**
Stationary Combustion	Carbon Dioxide (Fossil Fuel and Biomass), Methane, Nitrous Oxide
Industrial Process	Carbon Dioxide (Fossil Fuel and Biomass), Methane, Nitrous Oxide, PFCs
Flaring	Carbon Dioxide (Fossil Fuel), Methane, Nitrous Oxide
Venting	Carbon Dioxide (Fossil Fuel), Methane
Fugitives	Carbon Dioxide (Fossil Fuel), Methane, SF6
On-Site Transportation	Carbon Dioxide (Fossil Fuel and Biomass), Methane, Nitrous Oxide
Waste	Carbon Dioxide (Fossil Fuel and Biomass), Methane, Nitrous Oxide
Wastewater	Methane, Nitrous Oxide

For Alberta, the reporting requirements for facilities is much simpler. Up to 2018, facilities that emitted more than 50,000 tCO_2e were required to report emissions on a facility level to the Alberta Energy Regulator (AER). If facilities were under they limit, they could voluntarily report emissions but are not required to. Table S3 presents the categories of emissions reporting with the full document being available in [2]. The data that is released to the public includes overall CO_2, CH_4, N_2O, SF_6, HFCs and PFCs emitted by company and is available on the Alberta Environment and Parks website [3]. Each facility also has a sector identifier such as 'Electric Power Generation' or 'Conventional Oil and Gas Extraction'. There is no specific sector identifier for only natural gas operations, therefore all emissions associated with natural gas production is likely within the 'Conventional Oil and Gas Extraction' sector. As an example, one of Husky's Ram River facilities in the 2013-2014 year, emitted a total of 871.6 kt of CO_2, 8.6 kt of CH_4, and 1.8 kt of N_2O with not emissions of SF_6, HFCs or PFCs and is labelled as 'Conventional Oil and Gas Extraction'. The first hurdle is to determine the amount of emissions associated with natural gas production, as the only method would be to determine how much natural gas companies produced if that information is available, and then match that data with facilities and assign emissions based on an allocation method (energy, financial, mass, etc.).

Table S3 - Alberta Reporting Requirements

Reported Emissions Categories	Specified Gas Type
Stationary Fuel Combustion	CO_2, CH_4, N_2O

Industrial Process Emissions	CO_2, CH_4, N_2O, SF_6, HFC & PFC by species
Venting	CO_2, CH_4, N_2O
Flaring	CO_2, CH_4, N_2O
Leakage Emissions	CO_2, CH_4, N_2O
On-Ste Transportation Emissions	CO_2, CH_4, N_2O
Waste Emissions	CO_2, CH_4, N_2O
Wastewater Emissions	CO_2, CH_4, N_2O
Biomass CO2 Emissions	CO_2
CO2 sent off site	CO_2
CO2 geologically injected on site	CO_2
CO2 received on site locations	CO_2
Formation CO2	CO_2
Industrial Product Use	SF_6, HFC & PFC by species

S.2 Literature Review of Canadian NG and Methane Studies

In Senobari[4] analysis of BC natural gas has estimates for the Horn River, Montney and Conventional basins. This was performed using Skone et al.'s model which was published through NETL. The author's analysis relies on U.S. data for any apparent data gaps. For pre-production the well construction materials (casing, well diameter) [5], water management emissions (diesel, water treatment plant, and electricity use) [5], completions flaring [6], and well lifetime [5] relied on U.S. data. Data in the production process that came from Skone et al.[5] include well lifetime, workover data (frequency, venting & flaring amounts), liquids unloading data (frequency, venting & flaring amount) and NG composition (Montney and conventional). The parameters in processing that relied on U.S. data include NG used in dehydrators, glycol regeneration (sweetening), and compressor stations along with some flaring data for separators in the dehydration activity which came from Skone et al. [5]. The transmission process also relies heavily on U.S. data from Zimmerle et al. [7] for fugitives emission rate and NETL emission factors for pipeline construction (diesel used, pipeline parameters). This contributed to approximately ~60% of bottom-up emissions intensity estimates for Horn River, Montney, and Conventional methods. The majority of the U.S. data used is related to venting and fugitive emissions. The amount of missing venting/fugitive methane emissions is supported by recent studies that have looked at reported methane emissions and actual testing [8–11]. The aggregated emissions intensity of all natural gas production in B.C. that has been reported and released publicly is approximately 6.39 gCO_2e/MJ. This includes all conventional and unconventional production facilities that emit more than 10,000 tCO_2e/yr. The predicted emissions intensities for Montney basin and conventional methods are similar to the aggregated emissions intensity but the Horn River emissions intensity is significantly higher (almost 2x).

Coleman et al.[12] determined emission intensities from BC and AB through available public data. It seems that the estimation method only uses the reported data to the best of their abilities to separate it into 3 categories: Production, Processing, and Transmission. B.C. has a split for the 3 categories, but AB only has values inputted for Production and Transmission. This is because they are currently only able to determine company emissions, no granular detail of emissions is available. Therefore, gas producing company emissions will be contributed towards the production whereas transmission companies will be included for the transmission emissions. Current estimates for Coleman et al. are relatively low compared to Senobari[4]

Greenpath[9] measured venting emissions from pneumatic devices in five AB regions in 2016 and found that Provincial methane emissions could be ~500 kt CH_4 from those areas. By contrast, in 2013 (most recent data available) AB reported total methane emissions were 1,500 kt[3]. Therefore, either pneumatics represent a third of total methane emissions or total methane emissions are being underreported. Unfortunately, we are unable to determine the fraction of reported methane emissions in AB from pneumatics as that level of disaggregation is not available. Atherton et al.[8] conducted measurements of unconventional gas production and processing facilities in the Montney basin in BC. They find that reported emissions only account for 46% (52 kt CH_4/yr reported vs. 114 kt CH_4/yr estimated) of measured emissions from 2014. Tyner et al.[11] concluded that flaring and venting volumes during tight gas well completions were approximately 6 and 1.5 times higher respectively than CAPP estimates[13], but approximately 62% lower than US EPA estimates. This shows that there are inaccuracies in reported data estimates that could preclude a fulsome discussion of the magnitude of the emissions challenge and subsequently, the most efficient methods to reduce these emissions.

From 2013 to 2018, there have been multiple studies[6,7,22,23,14–21] performed by the Environmental Defense Fund (EDF) in collaboration with 140 research and industry experts from 40 institutions that quantify methane emissions from the US NG supply chain. Littlefield et al.[20] concluded from these studies that there is an estimated 1.7% methane leakage rate (1.3-2.2%, 95% confidence interval) compared to the EPA's estimated ~1.50% methane leakage rate on average US NG production. In a more recent study, Alvarez et al.[24] estimated overall methane leakage rate for the US at 2.3%, which is 60% higher than current EPA estimates for 2015. Alvarez et al.[24] aggregated facility-level measurements to arrive at the 2.3% estimate instead of component-level measurements.

Canadian regulatory bodies can use the methods and findings from the EDF studies to inform research and development of methane emissions quantification methods in the future for Canada. However, a separate but similar analysis of Canadian basins is required to quantify methane emissions from NG production in Canada, because production methods, flaring and venting regulations, and basin properties will differ between Canada and US, which results in different methane (and GHG) emissions profiles. Currently, PTAC has been involved in research pertaining to various aspects of reducing methane emissions from oil and gas operations in Western Canada[25].

S.3 Model Modifications

Emissions from upstream NG production can be grouped into four stages - pre-production, production, processing, and transmission. Pre-production emissions are associated with well construction and completions activities such as exploration, drilling, and optional hydraulic fracturing. Production related emissions includes well maintenance activities such as workovers & liquids unloading and a combination of venting, flaring, and fugitives (VFFs) from equipment (e.g. venting pneumatics). During processing, the raw NG is treated to meet sales specifications of the NG and NG liquids. The main activities during processing include acid gas removal, dehydration, compression, and refrigeration (for hydrocarbon dewpoint control on sales gas). Emissions from transmission activities include those emitted during the construction, operation and maintenance (O&M) of the pipeline and compressors.

To assess the greenhouse gas emissions intensity of Seven Generations Energy Ltd. upstream natural gas production, the model was adapted to incorporate their data. Some activities in the original model, such as sweetening, are not utilized because of aggregated data. To account for aggregated data some activity units had to be aggregated together with broader definitions. There are also cases where activities are not performed. The original model is tailored to U.S. unconventional operations and include all processing steps, which are used depending on the composition of the raw natural gas.

Pre-production was not altered in the model but there were cases of aggregated data. The diesel usage reported in Seven Generations Energy Ltd. dataset was split between drilling and hydraulic fracturing, and therefore we were unable to disaggregate the amount of diesel used for water treatment or the fracturing portion of completions. Total diesel usage for the entire pre-production phase was collected by Seven Generations Energy Ltd. from their own vehicles as well as their contractors (drilling rig, trucks, deliveries, etc.). The diesel used for water management was aggregated into drilling as we were unable to determine a proper estimation method.

The changes to the production phase include removing the majority of the processes (Liquids Unloading, Workovers, Other Point Sources, and Fugitives) and replacing these processes with an emissions intensity calculated through LDAR surveys that were analyzed by Roda-Stuart et al.[26] at Stanford University. From the data provided by Seven Generations Energy Ltd. there were no emissions data from workovers or liquids unloading, which are not performed by Seven Generations Energy Ltd. The Carbon Disclosure Program (CDP) reported fugitives and venting include all fugitives and venting from wellbores and processing facilities aggregated together. A team at Stanford University (Adam Brandt, Daniel Roda-Stuart, Arvind Pawan Ravikumar) accompanied Seven Generations through multiple LDAR sessions of Seven Generations facilities and determined a fugitive/venting emissions intensity of ~0.96 gCO_2e/MJ NG. Stanford's calculations for the fugitive/venting emissions intensity replaced the reported fugitive emissions from the Seven Generations Energy Ltd. emissions estimates in their CDP reported values.

For processing, stationary combustion is introduced because Seven Generations data did not disaggregate the combustion emissions from natural gas. This means that we are unable to assign emissions to sweetening, dehydration, processes for liquids treatment, compressors and any use in pre-production and production. No other changes were made to the model for processing. A significant amount of the activities that are available in the model were not used because of the aggregation of venting/fugitive emissions (LDAR analysis) and stationary combustion such as Other Point Sources, Pneumatics, Compressor Stations, etc.

Transmission emissions data was not available from 7G as they do not operate or own any pipelines to market. Therefore the model parameters from Senobari E. were kept constant for 7G. This involves some reliance on U.S. data, in particular the fugitive emission factor from pipelines as there have not been a significant amount of data from Canadian pipeline operators on pipeline emission factors for natural gas. The emission factor for natural gas from pipelines is from Zimmerle et al. which is part of the EDF methane study that looked at emissions from U.S. natural gas pipelines.

Emissions from land use were not considered in these emissions estimates as reliable data was not available at this time. While literature exists [27] to estimate land use related GHG emissions generally, its representativeness to this company's field locations was uncertain. The company has an initiative to conduct a more detailed data collection effort to determine site-specific emissions. We recommend that this data be added to the current analysis when available. It is also important to note that GHG emissions impacts of land use for NG extraction are typically small and therefore, do not make a material impact on the emissions intensity estimates.

S.4 Data Gaps between BC public datasets and NETL Model dataset

Senobari E. utilized US data to provide the data for gaps present in her analysis. The factors affected approximately 60% of the emissions intensity estimate for the three plays that were studied. For pre-production the well construction materials (casing, well diameter) [28], water management emissions (diesel, water treatment plant, and electricity use) [28], completions flaring [6], and well lifetime [28] relied on US data. Data parameters in the production process that came from Skone et al. [28] include well lifetime, workover data (frequency, venting & flaring amounts), liquids unloading data (frequency, venting & flaring amount) and NG composition (Montney and conventional). The parameters in processing that relied on U.S. data include NG used in dehydrators, amine regeneration (sweetening), and compressor stations along with some flaring data for separators in the dehydration activity which came from Skone et al. [28]. The transmission process also relies heavily on U.S. data from Zimmerle et al. [7] for fugitives emission rate and NETL emission factors for pipeline construction (diesel used, pipeline parameters).

Current regulations in BC require facilities that emit over 10 kt CO_2e/yr to report their emissions to the BC government[29]. Annual GHG industrial facility emissions inventory from the BC government from 2010 to 2016 is published on their website[30]. Emissions are reported in aggregate categories, making it difficult to attribute emissions to specific activities in the NG supply chain. For example, the activity 'stationary combustion' includes emissions associated with fuel use in dehydrators, sweetening units, drilling rigs, compressors, power generation, etc. 123 facilities were required to report their emissions in 2016, all related to oil and gas extraction or pipeline transport of NG[31]. In addition, 42 oil and gas facilities in BC that were under the 10,000 tCO_2e/yr threshold voluntarily reported their emissions. A more in-depth analysis of BC NG emissions would require a change in current reporting requirements and subsequent public availability.

The Alberta Environment and Parks (AE&P)[3] collects emissions data from oil and gas operations. The Specified Gas Emitters Regulation (SGER)[2] was utilized from its inception to the end of 2017. Since January of 2018, the Carbon Competitiveness Incentive Regulation (CCIR) replaced the previous SGER and decreased the reporting threshold to 10,000 tCO_2e. In contrast with BC, AB's reporting threshold under the SGER during that time only include facilities that emit more than 50,000 tCO_2e in the reporting year. In BC, 27% of reported GHG emissions originate from facilities that emit under 50,000 tCO_2e/yr for 2016 [31], which suggests that the 50,000 tCO_2e/yr SGER threshold in AB could omit a significant fraction of total GHG emissions. The emissions categories that are reported are included in table S.3 in the SI. I While CCIR provides additional guidance on calculation methods, threshold criteria, and other standards, reporting requirements are still not disaggregated to be able to assess lifecycle GHG emissions.

S.5 Suggested Reporting Structure

A full list of all potential model inputs as well as data to be reported are presented in Table S4. Table S4 contains all inputs to the model that a producer could potentially provide that are split into 3 tiers. Tier 1 parameters contain emissions data and parameters that have high variability and/or sensitivity, which are required to determine an emissions intensity for the activity and process. Tier 2 parameters aid in refining the accuracy of the emissions intensity estimate rather than actual emissions. Tier 3 parameters are more 'nice to have' and provide detailed information that is not vital to determining emission factors or sources but rather aid analysis of emissions. Tier 3 parameters can also sometimes be used to back calculate estimate tier 1 parameters (ex. Miles travelled and fuel efficiency of trucks). Table 4 also presents assumed parameters included in the model and are obtained from the EPA under the NETL Data Column. It is assumed that Canadian and US parameters are the same as the technologies for flares and emissions from fuel usage should be extremely similar.

Table S4 - Reporting Structure for Natural Gas production GHG emissions

Section A - PreProduction						
	Tier 1	Tier 2	Tier 3	**Example Units**	7Gen Data	NETL Data
A.1 - Well Drilling and Construction-Inputs						
Diesel use per well	x			L/well	172132	30702
Avg well diameter		x		in. or m	0.2184	0.2184
Avg thickness of well casing		x		in. or m	0.018	0.019
Avg Concrete thickness		x		in. or m		
Avg TD of well		x		m	6000	4572
Avg Ultimate Recovery (bcf) or daily production (mmscf) per well	x			bcf/well lifetime or mmscf/day	8.914	3.25
Avg lifetime of a well	x			yr	15	30
A.2 - Fracturing Pumping						
Diesel Use in fracturing	x			L/treatment-well	228308	51511
Electricity Use	x			MWh/tratment-well	0	
NG Use	x			L/treatment-well	0	
A.3 - Total Deliveries and Water Management for Fracturing						
Diesel use in trucks for water delivery	x			L/well	Embedded in A.1	40510.8
Diesel use in trucks for sand/proppant delivery	x			L/well	Embedded in A.1	1857
Diesel use in trucks for CO2/N2 delivery	x			L/well	Embedded in A.1	1857
Detailed Method						
Total amount of water use			x	Kg water/ treatment-well		
Average distance to water source			x	km		
Average truck capacity (for water)			x	Kg/ truck		
Average truck fuel efficiny (for water)			x	L diesel / 100 km		
Use of recycled water from recycling water flowback			x	%		
Use of ground water (just for water component)			x	%		
Total amount of CO2 use			x	Kg CO2/ treatment-well		
Average distance to CO2 source			x	km		
Average truck capacity (for CO2)			x	Kg/ truck		
Average truck fuel efficiny (for CO2)			x	L diesel / 100 km		
Total amount of propant use			x	Kg propant/ treatment-well		
Average distance to propant source			x	km		
Average truck capacity (for propant)			x	Kg/ truck		
Average truck fuel efficiny (for propant)			x	L diesel / 100 km		

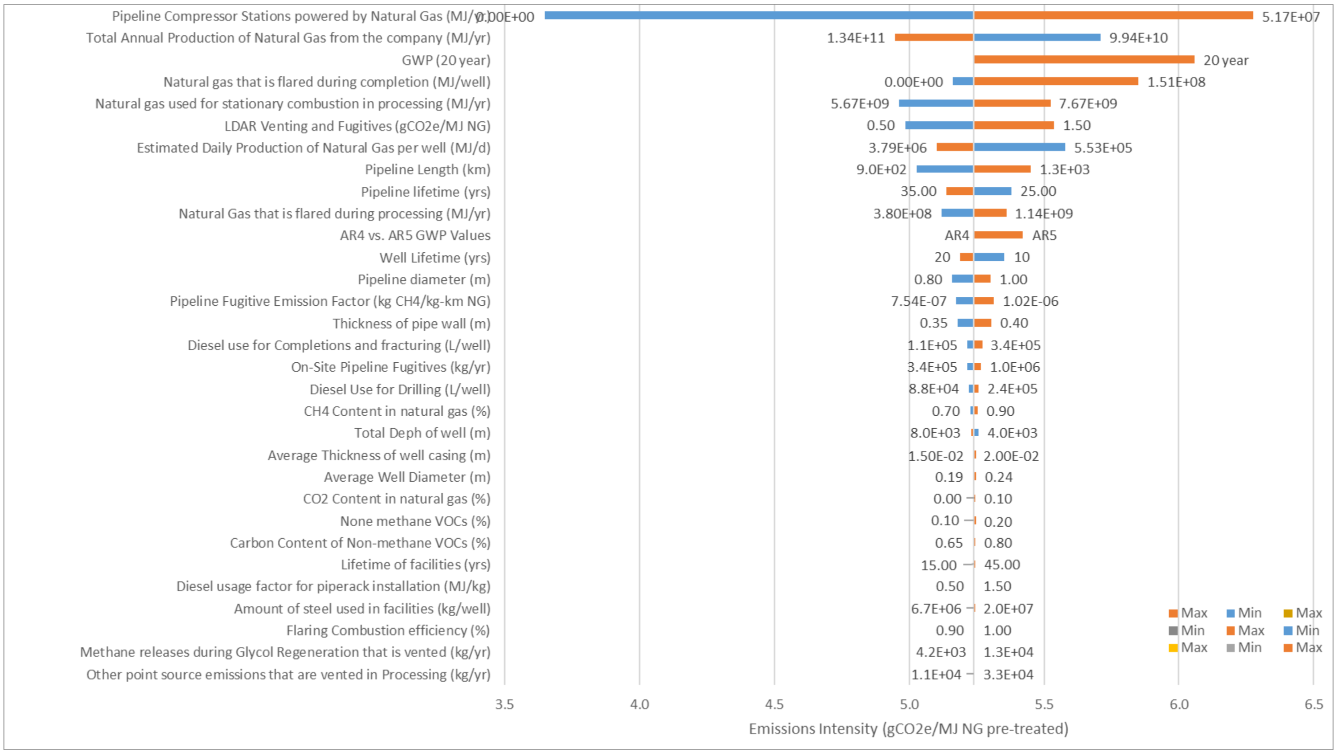
Operational Inputs - Water Management						
A.3.10 - Average total amount of flowback water			x	Kg water/well-treatment	3827537	4812750
A.3.11 - Average flowback water that is recycled			x	%	0.25	0.22
A.3.12 - Average water sent to wastewater treatment plant (WWTP)			x	%	0.75	0.78
A.3.13 - Other?			x	%		0
A.3.14 - Average totaL diesel use in trucks for flowback water management		x		L ofdiesel/Kg flowback water		0.002904
A.3.15 - Average Emission intensity from waste water treatment plant		x		g CO2e/Kg water treated		0.339
A.3.16 - average methane emissions vented after flowback		x		Kg methane /well-treatment		0
A.3.17 - Average CO2 emissions that are vented after flowback		x		Kg carbon dioxide /well-treatment		0
ENERGY INPUTS						
A.3.18-Diesel Use for water treatment		x		L diesel/Kg water		
A.3.19-Electricity Use for water treatment		x		MWh/Kg water		5.42E-05
A.3.20-Natural gas Use for water treatment		x		L NG/Kg water		
A.3.21- Average amount of water disposed in water injection wells			x	Kg treated water that is disposed/ Kg water treated		
A.3.22-Diesel Use for water injection pumps		x		L diesel/Kg water disposed		
A.3.23-Electricity Use for water injection pumps		x		MWh/Kg water disposed		
A.3.24-Natural gas Use for water injection pumps		x		L NG/Kg water disposed		
A.4 - Well Completion						
Amount of flaring incidents per year		x		# of times / total wells completed		
Amount of venting incidents per year		x		# of times / total wells completed		
Avg Volume raw gas vented per incident		x		kg/well or m3/well		
Avg Volume raw gas flared per incident		x		kg/well or m3/well		
Avg Volume Raw Gas Vented in well completion	x			kg/well or m3/well	373627	1700
Avg Volume Raw Gas Flared in well completion	x			kg/well or m3/well	0	26250
Average Annual Molar Raw Natural Gas Composition (%CH4,CO2,N2O, and others)		x		mol %'s	81.8, 0.7, 2.9, 14.5	78.8, 1.5, 1.8, 17.9
Flaring combustion efficiency		x		%	98	98
Section B - Production						
B.1 - Workovers						
Avg raw gas vented in workover	x			kg/episode or m3/episode	Embedded in B.4	148750
Avg raw gas flared in workover	x			kg/episode or m3/episode	Embedded in B.3	26250
Frequency of Workover episodes (refracking, water management, any other activities)	x			Episodes/yr	0	4.05
Avg well lifetime	x			yr	15	30
Flaring efficiency		X		%	98	98
Average Production rate and EUR	x			bcf/lifetime or mmscf/day	8.914	
Natural Gas molar Properties (%CH4,CO2,N2O, and others)		x		mol %'s	81.8, 0.7, 2.9, 14.5	78.8, 1.5, 1.8, 17.9
Avg Carbon content in non-methane HC's		x		%	83	
B.2 - Pneumatic Devices						
Avg NG vented in pneumatic devices	x			kg/yr or kg/well	Embedded in B.4	580000000
Avg Annual production of natural gas	x			kg/yr or kg/well	2526429990	4.82E+11
B.3 - Other Point Source Emissions						
Other point source emissions vented	x			kg/yr or kg/well	Embedded in B.4	24192719

Other point source emissions flared	x			kg/yr or kg/well	Embedded in B.3	4269303
B.4 - Other Fugitives in Production						
Avg fugitives from production (Methane and CO2)	x			kg/yr or kg/well	(LDAR) 0.96 gCO2e/MJ	388695205
B.5 - Liquid Unloading						
Avg NG Vented during Liquid Unloading	x			kg/well	0	1260
Avg NG Flared during Liquid Unloading	x			kg/well	0	0
Average Frequency of Liquid Unloading Episodes	x			episodes/well	0	1700
Section C - Processing						
C.1 - Sweetening/Amine Regeneration						
NG burned in reboiler as fuel	x			kg/yr or m3/yr	Embedded in C.7	6293445
Burned NG molar composition (H2S%)			x	mol %'s		
Molar Natural Gas composition before processing		x		mol %'s		
Amount of NG that is sweetened			x	kg/yr		2.80E+11
NG Vented during Sweetening	x			kg/yr		0
NG Flared during Sweetening	x			kg/yr		0
Carbon Dioxide Released during venting	x			kg/yr		3.64E+09
C.2 - Dehydration						
Annual NG burned as fuel	x			kg/yr or m3/yr	Embedded in C.7	41400000
Annual NG dehydrated			x	kg/yr or m3/yr		
Vented Natural Gas	x			kg/yr or m3/yr	Embedded in B.4	0
Flared Natural Gas	x			kg/yr or m3/yr	Embedded in B.3	0
Flaring Efficiency		x		%	98	98
Annual NG Vented from Seperators	x			kg/yr or m3/yr	8400	0
Annual NG Flared from Seperators	x			kg/yr or m3/yr	Embedded in B.3	1476165
Composition of Vented natural gas		x		mol %'s		
Composition of flared natural gas		x		mol %'s		
C.3 to C.5 - CO2 removal, other point source and fugitive emissions						
(NETL has not completed the CO2 removal section, currently included in sweetening)						
Electricity and Natural Gas usage for CO2 removal	x				Embedded in C.7	In Sweetening
Amount of Amine per k-mol CO2 used			x	kg/kmol or kmol/kmol or L/kmol		
Energy intensity of Amine solution pumping			x	kwh/m3		
Molar Natural Gas Composition before CO2 removal		x		mol %'s		
Avg Annual Venting from Other Point Sources and Fugitives	x			kg/yr	Embedded in B.4	242100000
Avg Annual flaring from Other Point Sources	x			kg/yr	16416590	71803000
C.6 - Compressor Stations						
Amount of Reciprocating Compressors			x	#		
Amount of Centrifugal Compressors			x	#		
NG Used in gas powered compressors	x			kg/yr	Embedded in C.7	10684871342
Electricity used in compressors	x			MWh		51746105
NG released from reciprocating gas powered compressors	x			kg/yr	Embedded in B.4	0
NG that is compressed from reciprocating gas powered compressors			x	kg/yr		

NG released with centrifugal powered compressors	x			kg/yr	Embedded in B.4	
NG compressed with centrifugal powered compressors			x	kg/yr		
Reciprocating Compressor Capacity			x	kg/hr or kg/yr		
Centrifugal Compressor Capacity			x	kg/hr or kg/yr		
C.7 - Stationary Combustion						
Amount of natural gas consumed	x			kg/yr or m3/yr	144226212.9	
Annual production of natural gas	x			kg/yr or m3/yr	2526429990	
Section D - Transmission						
D.1 - Transmission Operations					*Theoretical	
Length of pipeline	x			km	1100	971
NG consumption rate in transmission	x			MMscf/d NG or kg NG/yr-pipeline	28.8	2674014922
Electricity use for compressors	x			MWh	806000	119156
Number of gas powered compressors		x		#		
Number of electricity powered compressors		x		#		
Power of gas powered compressors			x	hp		
Power of electricity powered compressors			x	hp		
Capacity of gas powered compressors			x	kg/hr per compressor		
Capacity of electricity powered compressors			x	kg/hr per compressor		
Pipeline Fugitive Emissions	x			kg/yr or bcf/yr	8.87E-7 kg CH4/kg-km	1.99E+09
NG transported	x			kg/yr or bcf/yr	252642990	2.79709E+11
Electricity Emission Factors (possible multiple sources)	x			gCO2e/kWh	600	608
D.2 - Heavy Equipment use in pipeline contruction						
Avg Diameter of pipeline	x			m or in.	0.914	0.8128
Thickness of wall	x			m or in.	0.0125	0.375
Lifetime of pipeline	x			yrs	30	30
Diesel use in equipment and trucks	x			L	31482	27790

S.6 Sensitivity Analysis and Monte Carlo Simulation

The sensitivity analysis for the upstream section is presented in Figure S1 and the parameters that were changed and the quantity that they changed is in Table S5. If operational/emissions data was available to vary the input parameter such as the flaring during completions, then the standard deviation of said data was used. Otherwise the parameters were varied by a set percentage or amount that was deemed reasonable. This went up to +- 50% variation. The base case emissions intensity is 5.17gCO2e/MJ here as this used pipeline parameters estimated by 7G for a theoretical project instead of those used by Senobari E [4].



Base case emissions intensity: 5.17 gCO_2e/MJ NG.

Figure S1 - Sensitivity analysis for Pre-production, Production, and Processing for 7G

Table S5 - Sensitivity Analysis for Pre-production, Production, Processing Parameters and results

Name	Units	Minimum Emissions Intensity (gCO2e/MJ)	Maximum Emissions Intensity (gCO2e/MJ)	Minimum Input	Maximum Input
Total Annual Production of Natural Gas from 7 Gen	kg/yr	5.64	4.88	2.15E+09	2.91E+09
Natural gas that is flared during completion	kg/well	5.09	5.78	0.0	3.27E+06
Natural gas used for stationary combustion in processing	kg/yr	4.89	5.45	1.23E+08	1.66E+08
LDAR Fugitives	gCO2e/MJ NG	4.92	5.47	0.5	1.5
Estimated Daily Production of Natural Gas per well	MMscf/d	5.51	5.03	0.5	3.5
Other point source emissions that are flared in Processing	kg/yr	5.05	5.29	8.21E+06	2.46E+07
AR4 vs. AR5 GWP Values	gCO2e/g CH4	5.17	5.35	n/a	2.80E+01
Well Lifetime	yrs	5.28	5.12	1.00E+01	2.00E+01
Diesel use for Completions and fracturing	L/well	5.15	5.20	1.14E+05	3.42E+05
On-Site Pipeline Fugitives	kg/yr	5.15	5.20	3.37E+05	1.01E+06
Diesel Use for Drilling	L/well	5.15	5.19	8.81E+04	2.37E+05
CH4 Content in natural gas	%	5.16	5.19	7.00E-01	9.00E-01
Total Depth of well	m	5.19	5.16	4.00E+03	8.00E+03
Average Thickness of well casing	m	5.17	5.18	1.50E-02	2.00E-02
Average Well Diameter	m	5.17	5.18	1.90E-01	2.40E-01
CO2 Content in natural gas	%	5.17	5.18	0.00E+00	1.00E-01
None methane VOCs	%	5.17	5.18	1.00E-01	2.00E-01

Carbon Content of Non-methane VOCs	%	5.17	5.18	6.50E-01	8.00E-01
Lifetime of facilities	yrs	5.17	5.18	1.50E+01	4.50E+01
Diesel usage factor for piperack installation	MJ/kg steel	5.17	5.17	0.5	1.5
Amount of steel used in facilities	kg/well	5.17	5.17	6.70E+06	2.01E+07
Flaring Combustion efficiency	%	5.17	5.17	9.00E-01	1.00E+00
Methane releases during Glycol Regeneration that is vented	kg/yr	5.17	5.17	4200	1.26E+04

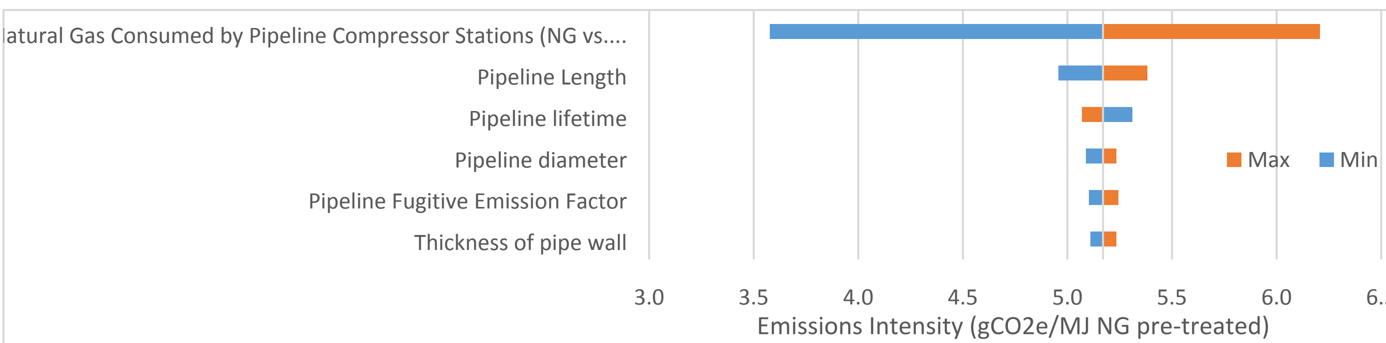
The parameters that are varied based on data provided by 7G are as follow:

- Total annual production of natural gas: 1118 +- 70 MMscf NG/d
    - Variation between 2016 Q4 and 2016 average production used [32]
- Natural gas flared during completions: 0 – 3.3E6 kg NG/well
    - 3.74E5 base, One standard deviation of available data used for range [33]
- Estimated Daily Production of Natural Gas per Well: 0.51 – 3.0 MMscf/d
    - Average well production analysis (Appendix A.4) and 2016 daily production data [32]

Other Parameters are varied by a set percentage amount:

- Natural Gas used for Stationary Combustion: varied by +-15%
- LDAR Fugitives: varied by +-50% (0.96 base value from Stanford analysis)
- Pipeline Length: varied by +- 200km
- Pipeline Lifetime: varied by +- 5 years
- Other point sources that are flared in processing: varied by +-50%

Similarly to the stage 1 sensitivity analysis, the sensitivity analysis for the transmission process of stage 2 was performed by varying parameters based on preliminary engineering design or by a set amount that was considered appropriate. The results of this sensitivity analysis are detailed Figure S2 and Table S6.



Base case emissions intensity: 5.17gCO_2e/MJ NG pre-treated

Figure S2 - Sensitivity Analysis results for Transmission for 7G

Table S6 - Sensitivity Analysis Results for Transmission Parameters

Name	Units	Minimum Emissions Intensity (gCO2e/MJ)	Maximum Emissions Intensity (gCO2e/MJ)	Minimum Input	Maximum Input
Natural Gas Consumed by Pipeline Compressor Stations (NG vs. Electric)	kg NG/yr	3.58	6.21	0.0	47.7
Pipeline Length	km	4.96	5.38	900	1300
Pipeline lifetime	yrs	5.31	5.07	25.0	35.0

Pipeline diameter	m	5.09	5.23	0.8	1.0
Pipeline fugitive emission factor	kg NG/kg-km NG transported	5.10	5.24	7.54E-07	1.02E-06
Thickness of pipe wall	m	5.11	5.23	0.075	0.025

Parameters varied based on available data:

- Natural Gas Consumed by Pipeline Compressor Stations: 0 - 48 MMscf/d & 0 - 1.93E6 MWh/yr
    - 28.8 MMscf/d & 8.06E5 MWh/yr base, all electric vs. all gas from BFD and Mtl Balance [34]

Other Parameters were varied by a set amount/percentage amount from base case

- Pipeline Length: Varied +- 200km to account for alternate routes to coast
- Pipeline lifetime: Varied +- 5 years as an estimated lifetime for pipeline
- Pipeline Diameter: Varied +- 10 cm
- Pipeline Thickness: Varied +- 1 inch
- Pipeline Fugitive Emissions: Varied +- 15%

The biggest contributor to the variability of transmission emissions is whether or not the compressor stations are entirely electric powered vs. entirely natural gas powered. The less sensitive parameters being related to the pipeline structure materials and lifetime as well as fugitives.

S.6.1 Monte Carlo Simulation

The MC simulation varies the same parameters considered in the sensitivity analysis to determine a probability distribution of potential GHG emissions for this company. Only 'well production' and 'completions flaring' data provided by the company contained enough data to inform a probability distribution for the MC simulation. For the parameters where distributions are not available, uniform distribution curves were assigned with the end-points used in the sensitivity analysis. Although uniform distributions have higher uncertainty compared to normal distributions, they can illustrate a wider range of variability when actual probability distributions are unknown. MC simulations are also performed for Senobari E.'s[4] results to provide meaningful comparisons to the case study, and to replace Senobari E.'s[4] previous uncertainty estimates which relied on the sensitivity analysis.

The results of the uncertainty analysis using MC simulation is presented in Figure S3, which shows P5 and P95 intervals of 3.73 and 5.36 CO_2e/MJ NG respectively for upstream emissions. The uncertainty range is small because company data parameters were used to inform distribution curves instead of uniform distribution assumptions. In addition, the analysis looks at NG production from a single producer in the Kakwa region of the Montney basin and therefore has lower variability than compared to overall basin-level estimates. The MC results for P95 and P5 of Senobari E.'s [4] BC estimates are 2.2 to 5.9 gCO_2e higher and 1.5 to 3.5 gCO_2e lower than the results for the bottom up analysis of Horn River, Montney, and conventional production. Senobari E.'s [4] analysis looked at overall BC NG production for Horn River and Montney basins, and conventional methods, which covers a wider range of production methods and operations than those assessed in this case study. Therefore, it is expected that the uncertainty for a wider range of production and multiple producers is needed to cover a wider range of emissions intensities.

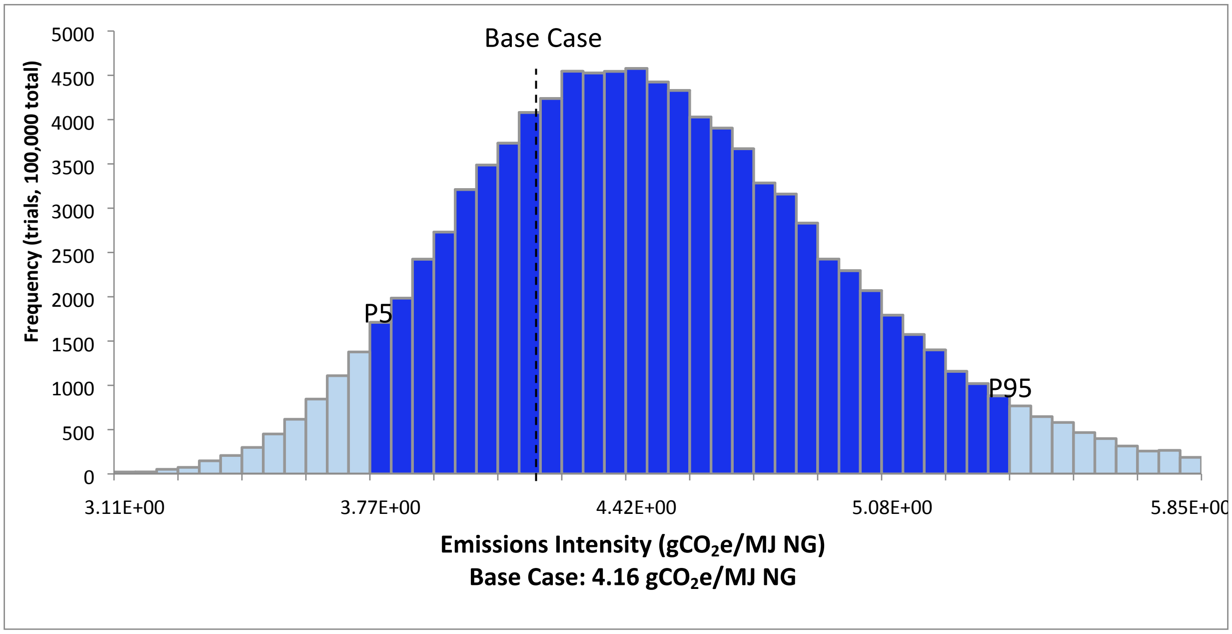
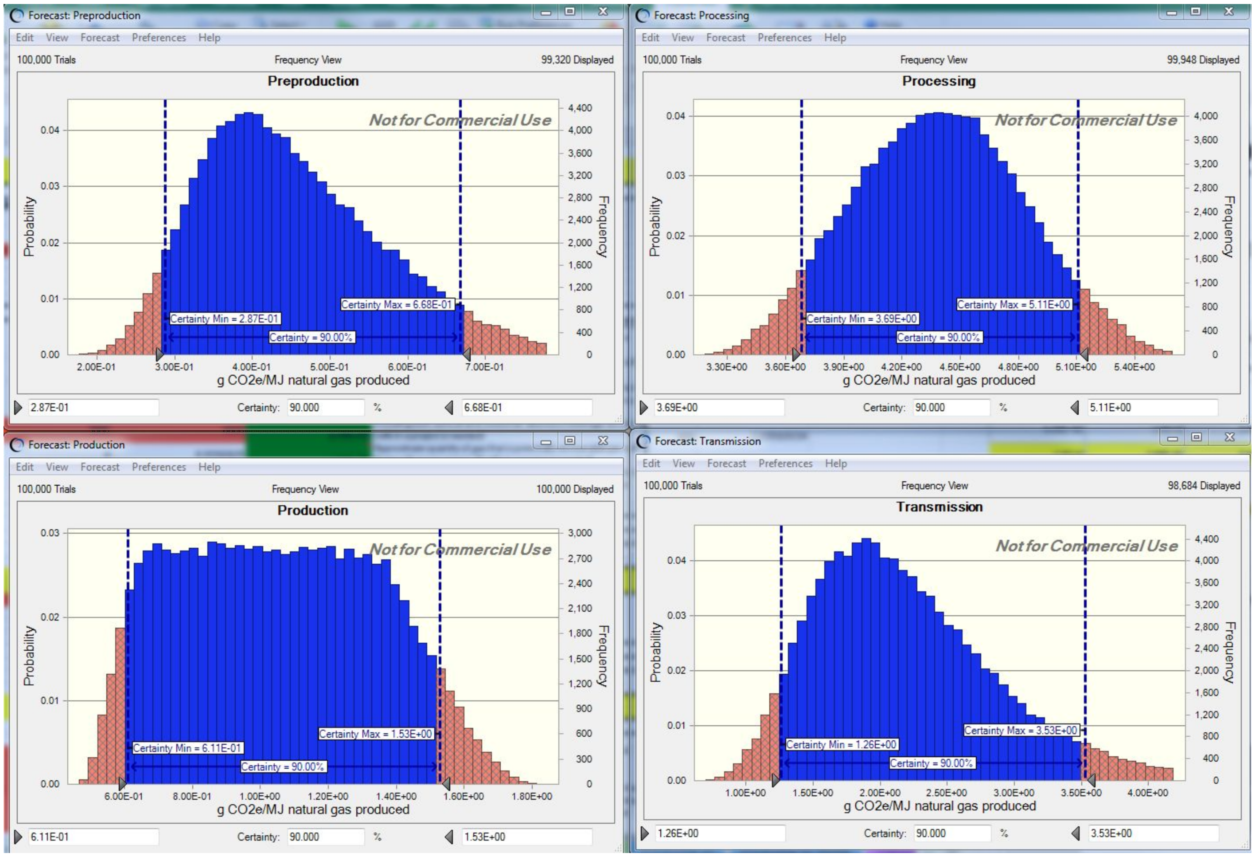


Figure S3 - Monte Carlo Simulation Results for Company Emissions Intensity Estimate. The darker blue is within the P5 and P95 limits, and the light blue is outside of the limits.

The results from the company's emissions intensity estimate compared to other Canadian and US studies indicate that disaggregated data allows for an emissions intensity estimate to be broken down to determine the sources of emissions. From these sources, it is possible to identify the main drivers of emissions. To be able to perform similar analysis on the company's emissions for AB and BC would require current public datasets to be disaggregated which can be done through data collection and releasing the detailed data collected publicly.

The Monte Carlo simulation for 7G's data was performed using all the parameters that were varied in the sensitivity analysis. Other than flaring data and diesel use, which a normal distribution could be fit to, all other variables were set to a linear function. Figure S4 presents the results for each process in the upstream. The simulation was run for 100,000 trials. A Monte Carlo simulation was not done for the downstream sector.



**Results are before allocation percentages are applied (~55% for energy allocation)*

Figure S4 - Monte Carlo Results for 7G

Pre-production variation had 5-95% intervals from 0.16 to 0.37 gCO_2e/MJ NG with a base case of 0.18 gCO_2e/MJ. It is seen that the distribution for pre-production is highly weighted towards the lower end of the spectrum. This is likely accounted for because of the relationship between the emissions released per well and the expected lifetime production of the well. As the production increases, the emissions intensity reduces at a slower rate than if production decreases, making a longer tail on the max end of the distribution.

The production emissions intensity had 5-95% intervals from 0.34 to 0.85 gCO_2e/MJ NG with a base case of 0.59 gCO_2e/MJ NG. The production emissions have a distinct plateau in its distribution as the vast majority of the emissions are dependant on the venting and fugitives in production, which is summarized as a single number in our study (LDAR study done by **Roda-Stewart et al.**). If the venting and fugitive emissions are allocated to their respective activities (pneumatics, compressors, workovers, etc.), a more accurate Monte Carlo simulation could be performed.

Processing variation had 5-95% intervals from 2.04 to 2.82 gCO_2e/MJ NG with a base case of 2.82 gCO_2e/MJ NG. Processing currently has only 3 data inputs that significantly affect the emissions intensity, natural gas use for stationary combustion (for dehydration, sweetening, other processing, compressors, etc.), annual natural gas production and flaring. Ideally stationary combustion as well as the venting and fugitives currently embedded in the LDAR emissions intensity could be disaggregated to the activity level which would allow better insights to the effects that would have on the emissions intensity.

Transmission variation has 5-95% intervals from 1.26 to 3.53 gCO_2e/MJ NG with a base case of 2.29 gCO_2e/MJ NG. The largest factor that contributes to the emissions intensity variation is the assumption of all electric (BC Hydro) vs. all gas-powered. Without potential electricity powered compressors with electricity provided by BC Hydro it is unlikely that the emissions intensity would be as low as 1.26 gCO_2e/MJ NG.

S.6.1.1Monte Carlo for BC Basin Emissions Intensities

The Montney, Horn River, and Conventional analysis from Senobari E. initially only had a sensitivity analysis performed. Below in Figure S5-S7 and Table S7 are the results of the monte carlo simulation for the 2 basins and conventional production methods. The parameters varied are in-line with Senobari E.'s sensitivity analysis and all parameters were assigned a linear fit.

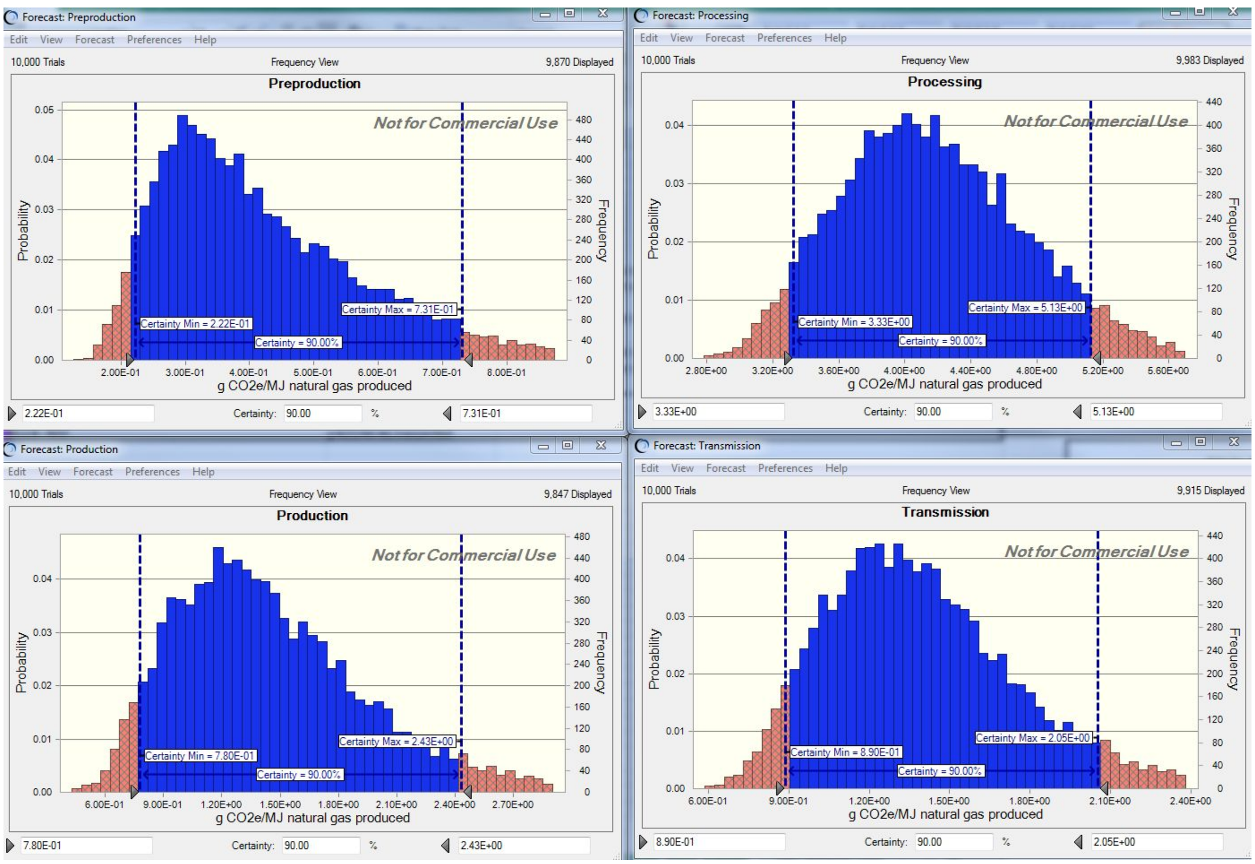


Figure S5 - Monte Carlo Results for Montney Formation (Addition to Senobari E. [11])

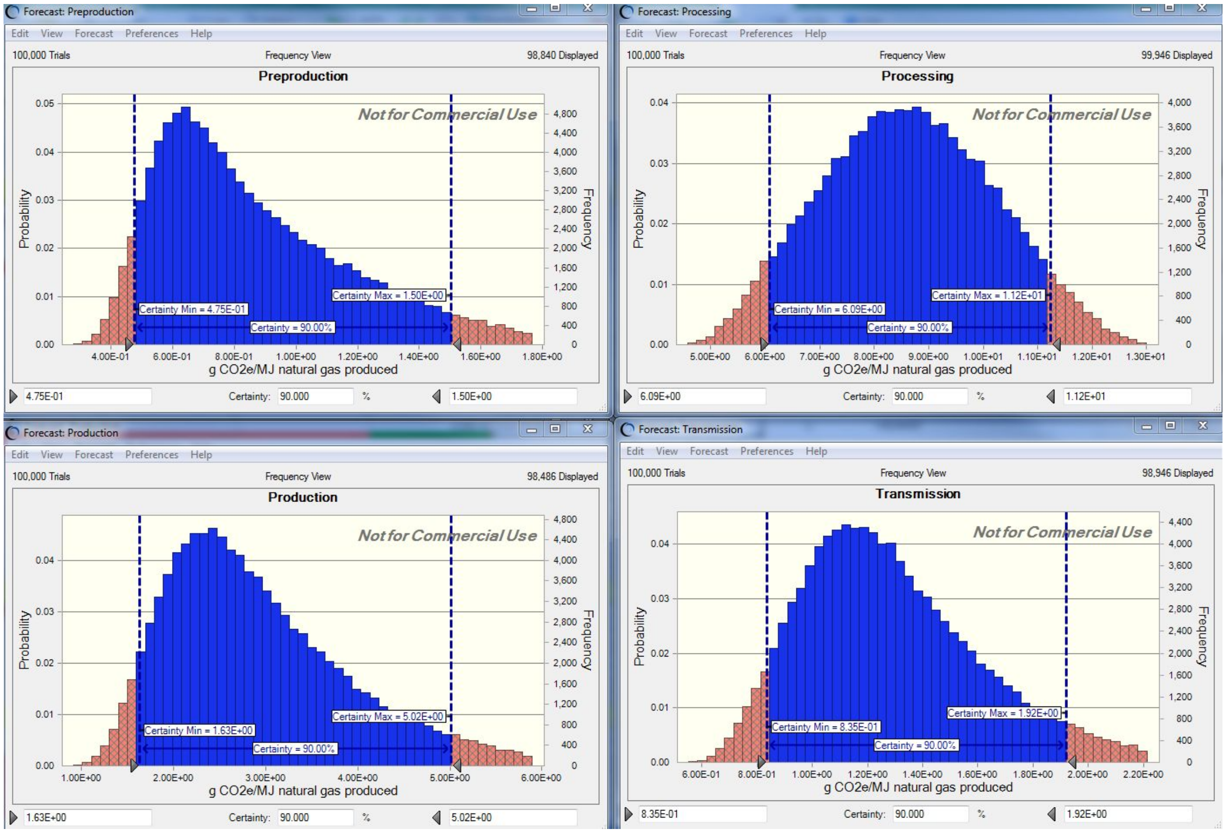


Figure S6 - Monte Carlo Results for Horn River Formation (Addition to Senobari E. [11])

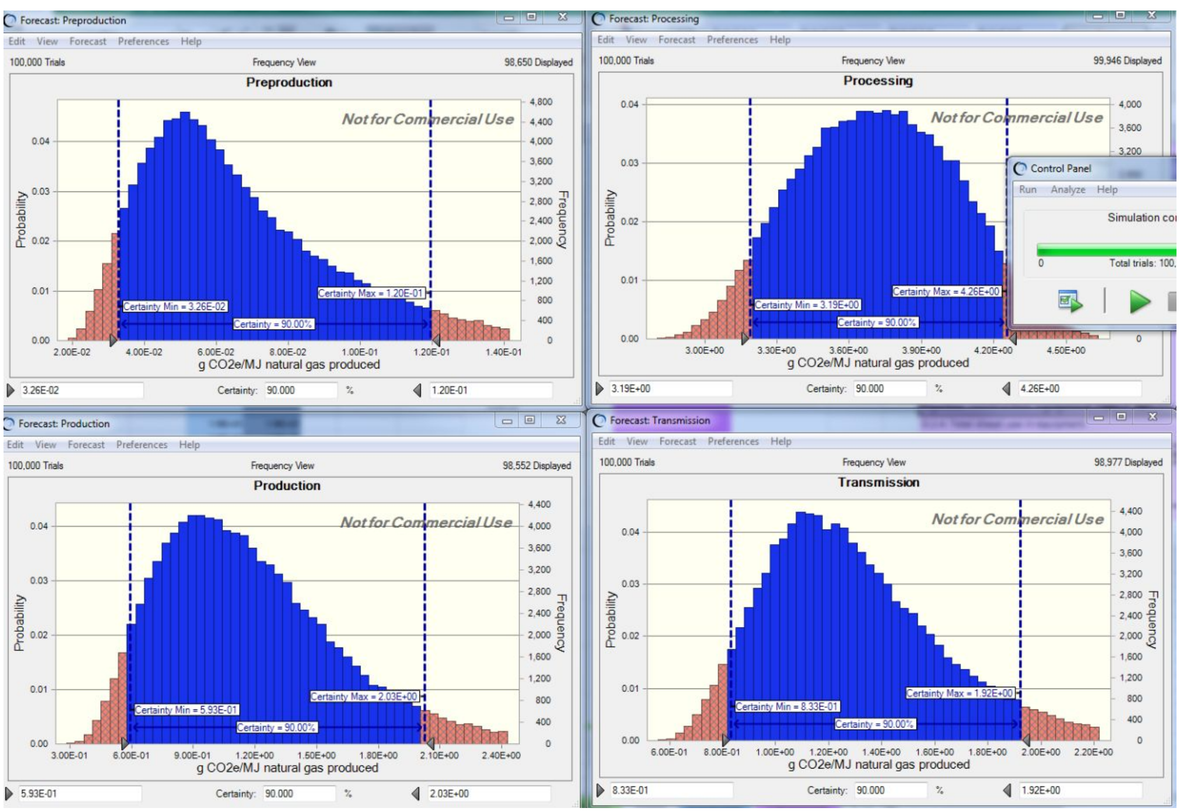


Figure S7 - Monte Carlo Results for Conventional production (Addition to Senobari E. [11])

Table S7 - Summary of Montney Carlo Results for BC Basins and BC Conventional

	Units: gCO2e/MJ								
	Montney			Horn River			Conventional		
Stage	Base	High	Low	Base	High	Low	Base	High	Low
Pre-production	0.41	0.73	0.22	0.75	1.55	0.47	0.15	0.21	0.089
Production	1.54	2.43	0.78	2.31	2.78	0.92	1.21	2.03	0.59
Processing	3.51	5.13	3.33	7.47	11.3	6.08	3.51	4.26	3.19
Transmission	1.28	2.05	0.89	1.28	2.05	0.83	1.28	1.92	0.83
Total	6.74	10.34	5.22	11.81	17.68	8.3	6.15	8.42	4.699

S.7 Allocation Calculations for Company Emissions

Overall production of the three products across 7G operations was determined from 2016 production data [32]. The amount of energy produced in the form of NG, condensate and NGLs was calculated using production volumes and energy content provided by 7G.

Allocation calculation are carried out for financial, mass, and energy detailed in Table S8-S12. Only energy allocation are used to determine the base case emissions intensity for stages 1 and 2. The production flow rates, product prices, densities and energy content are provided by 7G.

Table S8 - 2016 Production Data for Allocation Methods Calculations

Production Amounts	Amount	Units
Condensate	36.4	mbbls/d
Natural Gas	289.5	MMscf/d
Natural Gas Liquids	10.1	mbbls/d

Table S9 - Financial Allocation Results

Financial Allocation	Price	Revenue Amount ($/d)	Allocation (%)
Condensate	56.96$/bbl	2.08E+06	60%
Natural Gas	4.15$/Mcf	1.20E+06	35%
Natural Gas Liquids	18.23$/bbl	1.84E+05	5%

Table S10 - Mass Allocation Results

Mass Allocation	Flow Rate (m3/d)	Mass flow rate (kg/d)	Allocation (%)
Condensate	5.80E+03	4.49E+06	36.5%

Natural Gas	8.20E+06	6.89E+06	56%
Natural Gas Liquids	1.61E+03	9.36E+05	7.5%

Table S11 - Energy Allocation Results

Energy Allocation	Total Energy (MJ/d)	Allocation %
Condensate	1.88E+08	29%
Natural Gas	3.55E+08	55%
NGLs	9.96E+07	16%

Condensate displacement allocation subtracted the average condensate production emissions intensity of 3 condensate blends (Algerian, Snohvit, Margham) available in The Petroleum Refinery Life Cycle Inventory Model (PRELIM)[35] from the initial non-allocated emissions intensity estimate.

S.8 References

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