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Aggregation and Allocation of Greenhouse Gas Emissions in Oil and Gas Production: Implications for Life-Cycle Greenhouse Gas Burdens

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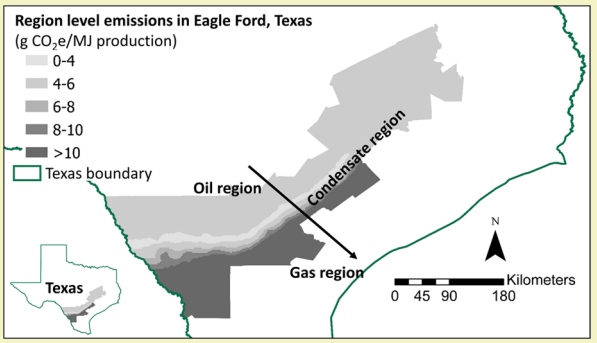
Supporting Information

ABSTRACT: Methods used for emission aggregation and allocation have significant impacts on life-cycle greenhouse gas (GHG) emission estimates for oil and gas products; however, because of limited data availability for upstream and mid-stream oil and gas operations, the influence of the allocation technique has not been extensively explored in previous studies. GHG emissions associated with oil and gas production and processing in the Eagle Ford Shale (with 34 gas processing plants and classified into 12 production regions) are estimated, using data from 2013, at three different scales of spatial aggregation (production region, gas plant and basin levels), to characterize the spatial variabilities in GHG emissions within the Eagle Ford Shale. GHG emissions per energy content of oil and gas products vary from 3.4 to 14 g CO_2e/MJ among the regions within the Eagle Ford Shale, and from 3.5 to 23 g CO_2e/MJ when assigned at the individual gas processing plant level, with a basin average of 6.8 g CO_2e/MJ. GHG emissions are also disaggregated at the equipment and operations level and allocated to gas and/or oil products. Using this disaggregated allocation method, a basin-wide average of 9.5 g CO_2e/MJ GHG emissions are allocated to gas products and 3.5 g CO_2e/MJ are allocated to the oil product. These emission estimates are compared to benchmark emission estimates from other datasets. This study provides insights into how choices of aggregation and allocation level influence GHG emission estimates for oil and gas products.



KEYWORDS: *greenhouse gas (GHG), life-cycle assessment (LCA), upstream oil and gas production, Eagle Ford Shale, allocation methods*

INTRODUCTION

Production of natural gas, natural gas liquids (NGLs: ethane, propane, butanes), and oil has increased significantly in the United States over the past decade, driven by increased production from shale formations, using horizontal drilling and hydraulic fracturing. Overall production of natural gas increased from 25.6 trillion cubic feet (tcf) in 2008 to 37.0 tcf in 2018;[1] production of oil increased from 1.83 billion barrels in 2008 to 4.01 billion barrels in 2018;[2] production of ethane and propane increased more rapidly than oil and natural gas over the same time period, with ethane increasing from 257 to 623 million barrels per year and propane increasing from 187 to 509 million barrels per year.[3,4]

Access to some markets for the final products made from these hydrocarbon resources depends on their life-cycle greenhouse gas (GHG) footprints. For example, hydrocarbon fuels used for transportation may need to meet criteria such as those imposed by the California Low Carbon Fuel Standard[5] or the standards imposed by the Energy Independence and Security Act of 2007.[6] Because many hydrocarbon production operations now produce gas, NGLs, and petroleum, life-cycle emission estimates of hydrocarbon products will depend on how emissions are allocated among the products and at what level of equipment aggregation the allocation is performed. Allocation methods on the basis of energy, mass, or market value are widely recognized to result in different life-cycle emission estimates for hydrocarbon products (e.g., Zavala-Araiza et al.'s study on natural gas supply chains,[7] Wang et al.'s study on petroleum refineries,[8] Guinée and Heijungs's study on fossil fuel chains,[9] Canter et al.'s study on biorefineries[10]

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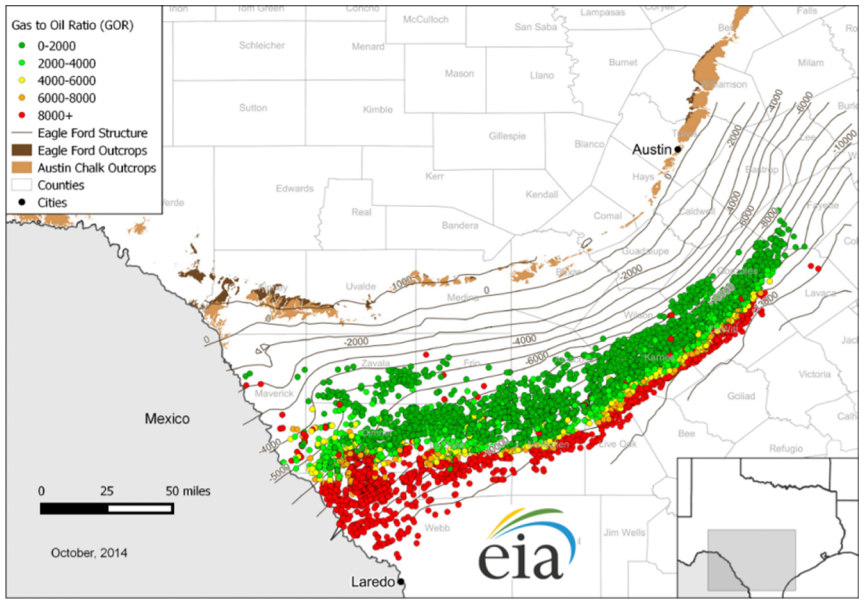

Figure 1. GORs of Eagle Ford wells (January 2000 to June 2014). Source: U.S. Energy Information Administration (December 2014).[15]

and Jaramillo et al.'s study on enhanced oil recovery systems[11]). Similarly, levels of equipment aggregation at which the allocation is performed will result in different life-cycle emission estimates for hydrocarbon products. For example, aggregation of refinery emissions at the unit operation level can lead to very different allocation of GHG emissions to specific products than aggregation at the refinery level.[12,13] While the importance of allocation and aggregation is understood well conceptually, until recently few data were available to support estimates of the significance of aggregation and allocation methods in upstream (well site) and mid-stream (gathering facilities, gas processing) operations.

This work will illustrate how GHG emissions assigned to hydrocarbon products can vary depending on methods used in allocation and aggregation of emissions in upstream and mid-stream operations. The sensitivity of GHG emission burdens to the nature of the wells (dry gas, wet gas or oil), and the assumptions made in performing the life-cycle analysis will be assessed. GHG emissions data from the Eagle Ford Shale oil and gas production region are used in the analysis because this region has wells that produce only gas (dry gas), gas and condensate (wet gas), and oil with associated gas (oil production), and is therefore broadly representative of a wide range of production characteristics. The Eagle Ford shale is a large oil and gas producing region in south central Texas. In 2013, the year for which the analyses in this work will be performed, hydrocarbon liquid production (oil and condensate) in the Eagle Ford Shale was approximately 1 million barrels (bbl) per day. Gas production was 4 billion standard cubic feet (scf) per day, leading to an average gas-to-oil ratio (GOR) of 4000 scf/bbl.[14] These overall average production statistics mask a wide variety of well types in the region. As shown in Figure 1,[15] GORs ranged from less than 2000 in the oil-rich northwest portion of the region, to more than 8000 in the dry gas southeast portion of the region. GHG emissions also varied across the region.

Calendar year 2013 data are used in the analyses since emission estimates, evaluated against ambient observations, have been published for this period. Cardoso-Saldaña, et al.,[16] report that emissions of methane in the Eagle Ford Shale production region are dominated by flashing from condensate tanks. Therefore, methane emissions are more extensive in the oil-rich portions of the region and are largely due to the parts of the supply chain (e.g., condensate tanks) associated with liquids (oil and condensate production). This means that GHG emissions, and especially methane emissions, attributed to the natural gas, NGL, and oil production will depend on the level of disaggregation employed in attributing the emissions, although this issue has not been explored in previous analyses of the region.[17−19]

As described later in this work, if GHG emissions are aggregated across the entire shale basin and allocated to oil, natural gas and NGL production based on the energy content of the products, approximately 36% of the emissions would be attributed to natural gas, 19% to NGLs, and 45% to oil. In contrast, if the production region is separated into oil, wet gas and dry gas regions, and emissions are allocated to oil, natural gas, and NGL production based on the energy content of the products, approximately 91% of the emissions would be attributed to natural gas, 2% to NGLs and 8% to oil in the dry gas region, and approximately 16% of the emissions would be attributed to natural gas, 21% to NGLs and 63% to oil in oil production regions. Finally, if emissions data are disaggregated by the equipment and operations producing individual products (e.g., emissions from condensate tanks attributed to oil products, rather than natural gas and NGLs), 50% of the emissions would be attributed to natural gas, 27% to NGLs, and 23% to oil over the basin.

This variability in GHG emissions assigned to hydrocarbon products from oil and gas production regions will be important in defining GHG emission burdens. The remainder of this paper describes the development of these emission estimates for the Eagle Ford Shale oil and gas production region and the methods used in aggregating and allocating emissions. Finally, the emission estimates in this paper are compared to benchmark emission estimates from other datasets.

METHODOLOGY

System Boundary for Oil and Gas Production. Figure 2 shows the system boundary for oil and gas production used in

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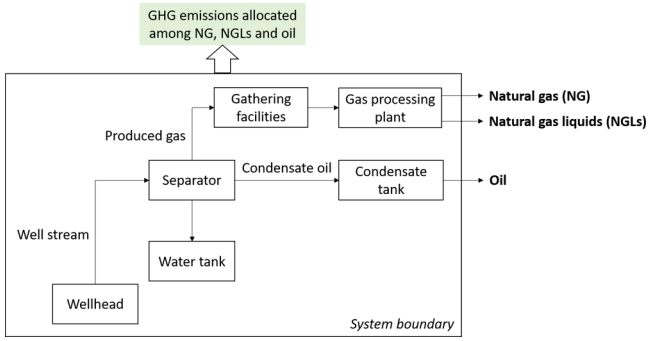

Figure 2. System boundary for oil and gas production.

this work, and the flows of hydrocarbons and sources of emissions inside the system boundary.[20] The well stream flowing from the wellhead is a mixture of liquid hydrocarbons, gas-phase hydrocarbons, and water. The well stream fluids flow to a three-phase separator, typically operating at approximately 1380 kPa (200 psia), where the fluid is separated into produced gas, condensate, and water streams. Condensate, which will also be referred to as oil in this work, and water streams are sent to condensate tanks and water tanks, which operate at atmospheric pressure. Some light hydrocarbons, including methane, which are present in the condensate and water liquid phases at separator conditions, flash and are emitted to the atmosphere from condensate and water tanks, which operate at atmospheric pressure. Some of the high-pressure produced gas leaving the separator is used on-site as fuel and to drive pneumatic systems. The bulk of the produced gas is sent to gathering facilities and gas processing plants, where the raw produced gas is dehydrated and sweetened. Pipeline-quality natural gas and NGLs are separated and sent to natural gas transmission systems and NGL transport systems. Natural gas, NGLs, and oil are the products from this production system. GHG emissions associated with all the oil and gas production operations, through gas processing, in the Eagle Ford Shale for the 2013 calendar year are considered in the system boundary. Compression of gas products for transmission purposes are assumed to occur in compressor stations downstream of gas processing plants and are beyond the system boundary of this study.

Production of Natural Gas, NGLs, and Oil in the Eagle Ford Shale. Production of gas and condensate in the Eagle Ford Shale are estimated well-by-well using data available from DrillingInfo.[21] Wells are grouped into 12 distinct production regions, based on the American Petroleum Institute (API) gravity of the liquids produced, and the GOR of the wells (see Supporting Information).[16,22] Based on production characteristics, well site conditions and well stream compositions, Cardoso-Saldaña et al.[16] developed a thermodynamic model to determine the compositions of individual molecular species in produced gas streams and condensate streams of each region (see Supporting Information). These molecular compositions of produced gas and condensate flows are assigned to individual wells based on the well locations.

Production of individual molecular species estimated for each well are then assigned to natural gas, NGL, and oil products. In this work, hydrocarbons ranging in carbon number from 1 to 4 (C1−C4) are assigned to gas products, while hydrocarbons with 5 or more carbons (C5+) are assigned to the oil product. Gas products are assigned to either pipeline-quality natural gas or NGLs. This work assumes that pipeline quality natural gas is 92.8% (mass) methane, with up to 5.54% (mass) nonmethane hydrocarbon components. The balance of the natural gas is assumed to consist of species other than hydrocarbons (e.g., CO_2, N_2).[7] At each well, all of the methane produced is assigned to the natural gas product, and ethane, up to the limit of the assumed natural gas composition, is also assigned to the natural gas product. Any remaining ethane, and all propane and butane are assigned to the NGL product stream.

The well-based production data for natural gas, NGLs, and oil are then aggregated at the level of individual gas processing plants, at the level of the dry gas, wet gas, and oil production regions of the Eagle Ford, and at the level of the entire Eagle Ford production region. Allen et al.[23] located 44 gas processing plants in the Eagle Ford Shale, by combining information from the U.S. Energy Information Administration (EIA) and the Environmental Protection Agency (EPA)'s Greenhouse Gas Reporting Program (GHGRP), and identified the individual wells associated with each gas processing plant by assuming gas products from each well are delivered to the closest plant where natural gas and NGLs are separated. Gas plants located on the edge of the Eagle Ford Shale with less than 10 associated wells (out of more than 20 000 wells in the Eagle Ford region in 2013) are eliminated, leaving 34 gas processing plants considered in this work. Production of natural gas, NGLs, and oil at individual wells were also assigned to dry gas, wet gas, or oil production regions based on well locations (see Supporting Information). These various aggregations of production data were combined with the lower heating values (LHVs) of the products to estimate the energy content of produced natural gas, NGLs, and oil, on gas plant, region, and basin levels, shown in Supporting Information. LHVs of the gas and oil products are calculated based on the heat of combustion of individual hydrocarbon components reported by National Institute of Standards and Technology (NIST).[24] Calculations of LHVs are described in Supporting Information.

GHG Emission Inventory for the Eagle Ford Shale. Methane emissions (fugitive and nonfugitive) from well site operations by source category in the Eagle Ford Shale are derived from the emission inventory developed by Cardoso-Saldaña et al., for the 2013 calendar year.[16] A base year of 2013 was chosen by Cardoso-Saldaña et al. to enable comparisons with other production regions and comparisons with ambient observations of light hydrocarbon concentrations. The comparisons with light hydrocarbon concentrations were used to evaluate the accuracy of the emission inventory. Oil and gas operations associated with each of the emission sources in the 2013 base case emission inventory and the emission estimation methods have been described by Allen et al.[20] These emission estimates were coupled with atmospheric dispersion models to predict atmospheric concentrations of methane and other light alkanes. Comparison of the predictions with observed light alkane concentrations led to the conclusion that propane emissions from condensate tanks were overestimated in the base case inventory. Cardoso-Saldaña et al. demonstrated that revised estimates of emissions of methane from tanks (based on the comparisons with propane observations), and from gathering operations, based on recent measurements (emissions equal to 0.42% of methane processed[25]) led to agreement with observations within the uncertainty bounds of observations and predictions. The adjusted emission rate of methane for gathering operations (0.42% of methane processed), consistent with observations, is

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used in this work, along with the methane and carbon dioxide emissions from other parts of the supply chain. CO_2 emissions from gathering facilities, primarily because of combustion of produced gas to drive compressors, are estimated based on compressor duties [estimated based on understanding of methane emission sources and U.S. EPA Compilation of Air Pollutant Emission Factors (AP-42)[26] and CO_2 emission factors for fuel combustion in compressors (see Supporting Information for details of this calculation).

GHG emissions due to energy demand from well site operations (excluding methane emissions which are covered by the 2013 base case inventory described above) and GHG emissions due to energy demand from gas processing plants are derived from the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET), a life-cycle model developed by Argonne National Laboratory.[27] GHG emissions reported in GREET represent the national average value of GHG emissions, including methane, nitrous oxide (N_2O), and CO_2 emissions from fuel combustion because of energy demand for shale gas recovery and processing. The GREET 2015 version, developed in 2015 based on emission data from EPA for the calendar year 2013, is applied so that emission estimates will be consistent with the time frame of this work.[28,29] The emissions derived from GREET (expressed as CO_2e emissions per energy content of throughput of products) are then aggregated on gas plant, region, and basin levels, based on the natural gas, NGLs, and condensate produced at each level.

Noncombustion methane emissions (venting and leakage) from gas processing plants are also derived from GREET. Another emission source at gas processing plants is CO_2 venting from acid gas removal (AGR) equipment. According to the US EPA Greenhouse Gas Inventory (GHGI) for natural gas systems in 2013, AGR vents contributed approximately 71% of CO_2 emissions from gas processing plants, flaring (e.g., flaring of H_2S) contributed 28.8%, and other CO_2 emission sources contributed <0.3% of these emissions.[30] For the Eagle Ford Shale where H_2S concentrations in produced gas are negligible,[16] CO_2 emissions from venting at gas processing plants are assumed to be dominated by AGR emissions. CO_2 emissions venting from AGR are estimated by assuming all CO_2 in produced gas is eventually emitted to the atmosphere. Fugitive CO_2 emissions from other emission categories are not estimated individually because these emissions have been accounted for in AGR venting (see Supporting Information). Table 1 summarizes sources of emission estimates in this work.

GHG Emission Aggregation/Disaggregation and Allocations. Allocation methods are commonly used in life-cycle assessment (LCA) when multiple products are produced. For the production of natural gas, NGLs and oil products, GHG emissions, either aggregated or disaggregated by equipment type, could be allocated among natural gas, NGLs and oil products based on their mass, energy content, or economic values. GHG emissions allocated to each product, however, can vary significantly with the allocation method. Energy-based allocation is applied in this study because the oil and gas products are primarily energy products. Allocation approaches for aggregated and disaggregated emissions are developed, using energy allocation among products.

Figures 2 and 3 illustrate two different methods for the allocation of emissions. GHG emissions from all the operations associated with oil and gas production can be aggregated and allocated among natural gas, NGLs, and oil based on the energy content of each of these product streams (quantified by lower heating values), on the gas plant, region, or basin levels. Figure 2 illustrates this aggregation at the regional level. This type of aggregated allocation that considers all the processes and operations in whole systems is commonly used in LCA studies. It ignores, however, that the GHG burdens of different equipment and operations, which play different roles in the production of each energy product, vary.

Table 1. Greenhouse Gas Emission Sources and Emission Components Associated with Oil and Gas Operations in the Eagle Ford Shale

emission source	emission component	source of emission estimates
Operations Associated with Oil and Gas Production		
completion flowbacks	CH_4	Cardoso-Saldaña et al.[16]
liquid unloading	CH_4	Cardoso-Saldaña et al.[16]
chemical injection pumps	CH_4	Cardoso-Saldaña et al.[16]
equipment leaks	CH_4	Cardoso-Saldaña et al.[16]
pneumatic controllers	CH_4	Cardoso-Saldaña et al.[16]
water tank flash	CH_4	Cardoso-Saldaña et al.[16]
fuel combustion/flaring on well sites	CO_2, N_2O	GREET 2015[28]
Operations Associated with Gas Production		
gathering and compression	CH_4, CO_2	Marchese et al.,[25] AP-42[26]
gas processing leaks	CH_4	GREET 2015[28]
processing equipment venting	CO_2	Cardoso-Saldaña et al.[16]
fuel combustion in processing plants	CH_4, CO_2, N_2O	GREET 2015[28]
Operations Associated with Oil Production		
condensate tank flash	CH_4	Cardoso-Saldaña et al.[16]

ISO 14041 recommends that LCAs should incorporate unit process-level details when input and output data are available for process burden allocation among products.[31] As shown in Figure 3, GHG emissions can be disaggregated by equipment and each type of equipment can be categorized as oil related, gas/NGL related, or oil and gas/NGL related. Three sub-boundaries are identified in Figure 3: well sites, gathering and processing facilities, and oil tanks. GHG emissions from well site operations, at the wellhead and from separators and water tanks, are associated with both oil and gas/NGL production and are allocated among natural gas, NGL, and oil products on an energy basis. GHG emissions from gathering and processing facilities that deal with gas/NGL products are allocated between natural gas and NGL products. GHG emissions from condensate tanks for oil storage are allocated to the oil product alone. Allocations are based on the energy content of the products and emissions are aggregated at the levels of gas plant, region, and basin.

The allocated emissions are then normalized by the energy production of the oil and gas products. All the GHG emissions are weighted as equivalent CO_2 (CO_2e) emissions based on their global warming potentials (GWPs) over 100 years, as reported by Intergovernmental Panel on Climate Change (IPCC).[32] The results are expressed as grams of equivalent CO_2 emissions per MJ oil or gas production (g CO_2e/MJ).

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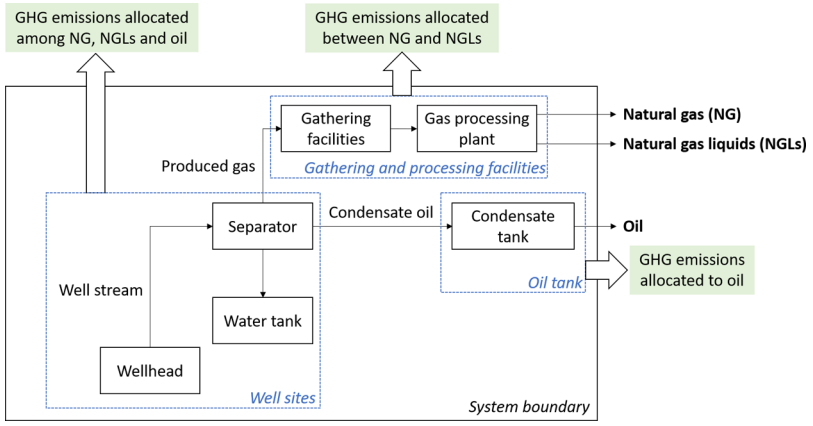

Figure 3. Allocation of disaggregated emissions by oil and gas operations.

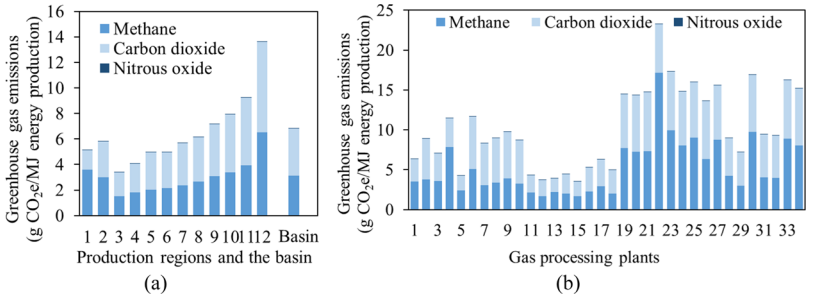

Figure 4. Aggregated GHG emissions (CO_2e) allocated to oil and gas products based on their energy production (LHVs) on: (a) region and the entire basin levels; (b) gas plant level. For this regional allocation, emissions have not been disaggregated by processing equipment, and are therefore identical for natural gas, NGLs, and condensate within each region.

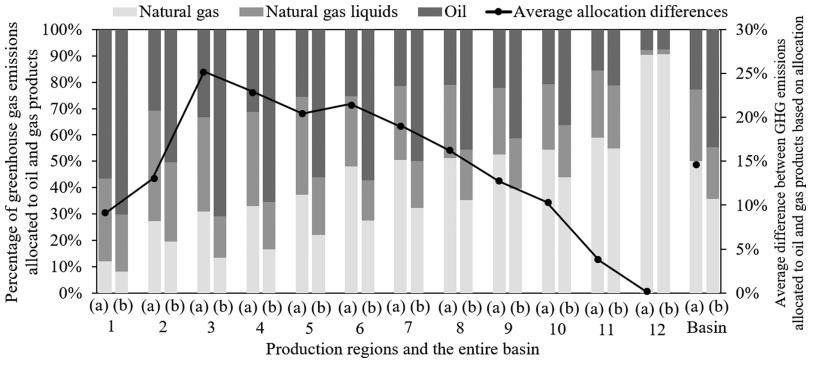

Figure 5. Percentage of GHG emissions (CO_2e) allocated to natural gas, NGL, and oil products based on their energy production (LHVs) on the region and basin levels, by 2 allocation methods: (a) GHG emissions disaggregated by oil and gas operations; (b) GHG emissions from all operations aggregated across the region and basin, and the average difference in percentage between GHG emissions allocated to natural gas, NGL, and oil products based on the allocation technique.

The GWP values used for GHG impact estimates in this study, and the equations for emission allocation and normalization are described in Supporting Information.

RESULTS AND DISCUSSION

Spatial Variability in GHG Emissions across the Eagle Ford Shale. GHG emissions are allocated to oil and gas products based on their energy production (LHVs) and are normalized by energy production on region, gas plant, and basin levels to identify the spatial variability in GHG emissions across the Eagle Ford Shale, as shown in Figure 4. The results in Figure 4 are reported as CO_2e/MJ and because the results at this level of analysis have not been disaggregated by processing equipment, are identical for natural gas, NGLs, and condensate within each region. Gherabati et al.[22] identified 12 production regions in the Eagle Ford. Regions 1−5 can be characterized as oil production regions (GOR < 2000); regions 6−11 can be classified as wet gas regions (2000 < GOR < 50000); region 12 can be classified as a dry gas region (GOR > 50 000). Region 12, the dry gas region, has the highest GHG emissions per amount of energy produced (14 g CO_2e/MJ). Among the 12 oil and gas production regions, oil production regions 1 and 2 have larger contributions of their GHG emissions per energy produced that are due to methane. These methane emissions are dominated by emissions from pneumatic controllers and condensate tanks. When aggregation is performed at the level of gas plants, which are distributed throughout the 12 regions, normalized GHG emissions vary from 3.5 to 23 CO_2e/MJ

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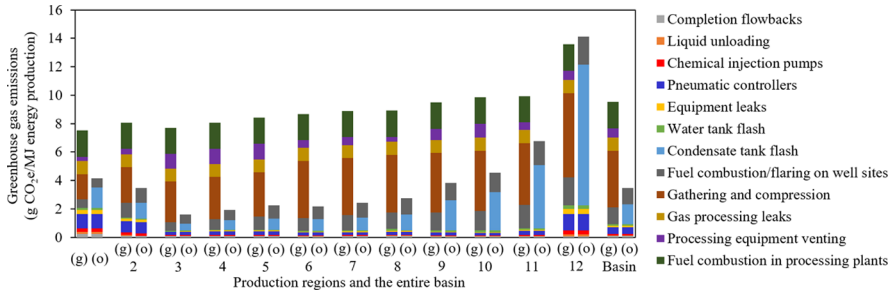

Figure 6. Disaggregated GHG emissions (CO_2e) by oil/gas operations allocated to: (g) gas products (natural gas and NGLs); (o) oil products, based on their energy production (LHVs) on region and basin levels.

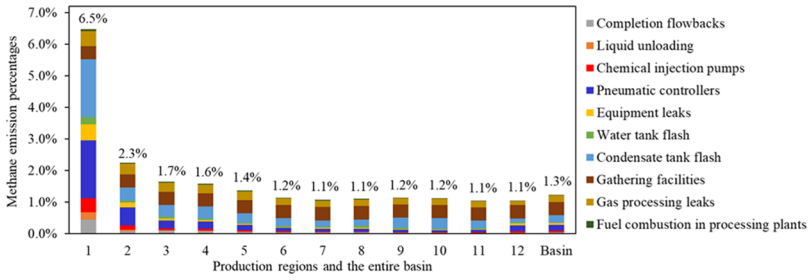

Figure 7. Methane emission percentages on regional and basin levels in the Eagle Ford Shale.

energy produced. Consistent with emission magnitudes at regional levels, GHG emissions from plants 1−10, located in oil production regions 1 and 2, are generally higher than from plants 11−18 located in other oil and wet gas production regions. Plants 19−34, located in dry gas production region 12, have normalized emissions higher than the emissions in the liquids producing regions. This is largely due to high methane and CO_2 emissions from gathering operations that deal with large amounts of gas products in the dry gas production region. 80% of the plants have GHG emissions less than 15 g CO_2e/MJ and only 1 plant has GHG emissions exceeding 20 g CO_2e/MJ. The plant with the highest GHG emission level is located in the dry gas production region. The average emission value for the entire basin is 6.8 g CO_2e/MJ, with 46% contributed by methane emissions and 54% contributed by CO_2 emissions, as shown in Figure 4a. N_2O emissions, despite their high GWP, have minimal impacts on total GHG emissions compared to methane and CO_2 emissions because this gas is emitted at low levels.

Comparison of Aggregated Allocations and Allocations Disaggregated by Oil/Gas Equipment and Operations. Methods of GHG allocation among oil and gas co-products can have a significant impact on GHG burdens. Figure 5 shows percentages of GHG emissions allocated to gas and oil products by aggregated and disaggregated allocation methods on regional and basin levels. GHG emissions assigned to gas products are lower using approaches that use aggregated allocations, compared to the disaggregated allocations on the equipment level, except for the dry gas production region 12. These variations are mainly because of emissions from high-emitting gas operations, which are allocated between gas and oil products in an aggregated allocation but are assigned more to gas products when performing disaggregated allocations because they are not associated with extensive (or any) oil production. The average differences (absolute values) in percentages of GHG emissions assigned to natural gas, NGL, and oil products between the two allocation methods in the 12 regions are also calculated and shown in Figure 5. These differences are relatively small in drier production regions, especially regions 11 and 12, where energy production of gas products dominate the total energy production and the allocation technique applied to GHG emissions from gas operations has little influence on the results. Though regions 1 and 2 have the largest shares of oil production, the differences in GHG emissions as a result of allocation choice are not the largest among the 12 regions, again because of the predominance of a single product (in this case oil). Results are most sensitive to the handling of GHG emission allocations in condensate production regions (wet gas), which have relatively large amounts of both gas and liquid products, rather than in oil and dry gas production regions.

Disaggregated GHG emissions allocated to gas and oil products in each production region and the entire basin are shown in Figure 6. With disaggregated allocations, GHG emissions from each type of equipment or operation, which may be either uncontrolled or partially controlled, are assigned to gas and/or oil products. GHG emissions from gathering facilities, including both fugitive and nonfugitive methane emissions and CO_2 emissions because of fuel combustion, dominate GHG emissions allocated to gas products. Other emission behaviors are more complex. For example, the emissions from condensate tanks show complex variation with condensate flow because tanks with condensate flow above a threshold level are required to install emission controls. Therefore, some wells with low condensate flow may have greater tank emissions than wells with higher condensate flows. Methane emissions from condensate tanks in oil production regions, which could be high because of large amounts of oil produced, are reduced because of emission controls on tanks. The aggregated and disaggregated GHG emissions allocated to gas and oil products on region, plant, and basin levels are shown in Supporting Information.

Methane Emission Percentages in the Eagle Ford Shale. A frequently used metric in reporting methane

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emissions in oil and gas production is methane emissions normalized by the total production of methane in the natural gas product and expressed as a percentage. This metric, referred to as the methane emission percentage, is shown in Figure 7. Region 1, with the largest amount of condensate oil production, has the highest methane emission percentage, 6.5%, among the 12 production regions in the Eagle Ford Shale. The largest emission contributors to this highest methane intensity are the condensate tank flash and pneumatic controllers. The relatively high methane emissions from condensate tanks and pneumatic controllers, together with the relatively low gas (methane) production in region 1 compared to the other regions, leads to the high percentage. Methane emission percentages in condensate and dry gas production regions (condensate regions 6−11, dry gas region 12) are around 1.1% and are relatively lower than in oil production regions (regions 1−5, methane intensities ranging from 1.4 to 6.5%). The largest three methane emission contributors in condensate production regions 6−11 are condensate tank flash, gathering facilities, and gas processing leaks, which account for approximately 80% of methane emissions in these regions. In contrast, the largest three methane contributors in oil regions 1 and 2 are pneumatic controllers, gathering facilities, and condensate tank flash, and in dry gas region 12 are pneumatic controllers, gathering facilities, and gas processing leaks. The basin average methane emission percentage is 1.3% in 2013, with methane emissions from gathering facilities, condensate tanks, and gas processing plants contributing 71% of total methane emissions.

Comparison to Benchmark Emission Data. GREET simulates energy demands and GHG emissions from benchmark fuels. GHG emissions from upstream shale production are reported as 9.5 g CO_2e/MJ fuel in the 2018 version of GREET[33] (the most current version available) and as 8.3 g CO_2e/MJ fuel in the 2015 version of GREET[28] (the version applied in this work since it is based on 2013 GHGRP data). Table 2 compares the national-level GHG emissions (listed by molecular species) per energy content of gas products from shale resources estimated by GREET and the average basin value in the Eagle Ford Shale estimated in this study with the disaggregated allocation method. Compared to GREET estimates, the basin average emission estimates in the Eagle Ford Shale developed in this work applied a spatially resolved emission inventory for well site methane emissions, added both methane and CO_2 emission estimates for gathering facilities (not included in GREET), and estimated CO_2 emissions venting from AGR equipment at gas processing plants based on produced gas compositions. Overall emissions estimated in this work are 15% higher than GREET 2015 estimates, mainly because GHG emissions from gathering operations in GREET were lower due to lack of data. Estimates of nitrous oxide emissions in this study and in GREET are comparable.

Table 2. Comparison of the Basin Average GHG Emissions in the Eagle Ford Shale in 2013 and GHG Emission Estimates in the GREET 2015 and 2018 Versions

GHG emissions (g CO_2e/MJ gas production)	GREET 2015	GREET 2018	basin value in the Eagle Ford Shale for 2013
CH_4	3.7 (±0.20)	5.4 (±0.23)	3.8
N_2O	0.01 (±0.003)	0.008 (±0.003)	0.007
CO_2	4.6 (±1.6)	4.0 (±1.5)	5.7
total	8.3	9.5	9.5

When compared to the latest version of GREET, the methane emissions estimated for the Eagle Ford Shale in 2013 are approximately 30% lower than the national value estimated by GREET 2018 because of multiple factors. First, upstream methane emissions among different shale production basins exhibit significant variability due to differences in geographical characteristics, gas/oil extraction technologies, and emission control strategies. The emission burdens estimated by GREET represent a national average value, while this study focuses on the Eagle Ford oil and gas production region. In addition, the nature of oil/gas production and emissions from these production activities vary with time. Emission estimates in GREET 2018 are based on natural gas throughput data in the calendar year 2016.[34] Emission estimates in this study, however, are based on shale oil/gas production activities and emission measurements during the calendar year 2013. Previously existing emission inventory methods underestimated some emission sources but the GREET 2018 model has updated emission estimates with the latest activity and emission factors.[34,35] Also, estimates from GREET might be biased high, compared to the equipment level disaggregation used in this study because emissions are aggregated and simply normalized by gas production. Uncertainties in GREET estimation are quantified by standard deviations described in Supporting Information.

CONCLUSIONS

Spatial variabilities in GHG emissions in the Eagle Ford Shale are estimated based on production activities and emission inventories during the calendar year 2013. With 12 production regions and 34 gas processing plants, GHG emissions per energy production of oil/gas products vary regionally from 3.4 to 14 g CO_2e/MJ, and from 3.5 to 23 g CO_2e/MJ on the plant level, with a basin average of 6.8 g CO_2e/MJ. However, these estimates depend on how emissions are allocated to oil and gas products, especially in wet gas regions with comparable amounts of oil and gas production. If GHG emissions are disaggregated by equipment and operations associated with gas and/or oil production, more GHG emissions are allocated to gas products (9.5 g CO_2e/MJ) and less GHG emissions are allocated to the oil products (3.5 g CO_2e/MJ) on a basin-average basis.

While these results are specific to the Eagle Ford region, the analysis highlights the importance of performing disaggregated emission allocation, if possible, especially for the increasing number of production regions producing both oil and gas products. Aggregated allocation may still be a preferred method in oil production regions or in dry gas production regions because it requires less detailed process modeling. However, in wet gas/condensate production regions, such as in parts of the Eagle Ford Shale, emission allocations disaggregated by oil/gas equipment can lead to emission allocations that are more than a factor of 2 different than allocations not including disaggregation by equipment type. The equipment level process and emission modeling tools, such as those described by Allen, et al.,[20] can enable this level of disaggregation.

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■ ASSOCIATED CONTENT

Supporting Information

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Production region and gas processing plant information in the Eagle Ford Shale; regional compositions of produced gas and condensate oil in the Eagle Ford Shale; calculations of energy production of natural gas, natural gas liquid (NGL) and oil products in the Eagle Ford Shale; CO_2 emissions on well sites and from gathering facilities; GHG emission inventory for the Eagle Ford Shale; GHG emission allocation; and data quality and uncertainties (PDF)

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Notes

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