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# Energy Intensity and Greenhouse Gas Emissions from Oil Production in the Eagle Ford Shale

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*Supporting Information*

**ABSTRACT:** A rapid increase in horizontal drilling and hydraulic fracturing in shale and "tight" formations that began around 2000 has resulted in record increases in oil and natural gas production in the U.S. This study examines energy consumption and greenhouse gas (GHG) emissions from crude oil and natural gas produced from ~8,200 wells in the Eagle Ford Shale in southern Texas from 2009 to 2013. Our system boundary includes processes from primary exploration wells to the refinery entrance gate (henceforth well-to-refinery or WTR). The Eagle Ford includes four distinct production zones—black oil (BO), volatile oil (VO), condensate (C), and dry gas (G) zones—with average monthly gas-to-liquids ratios (thousand cubic feet per barrel—Mcf/bbl) varying from 0.91 in the BO zone to 13.9 in the G zone. Total energy consumed in drilling, extracting, processing, and operating an Eagle Ford well is ~1.5% of the energy content of the produced crude and gas in the BO and VO zones, compared with 2.2% in the C and G zones. On average, the WTR GHG emissions of gasoline, diesel, and jet fuel derived from crude oil produced in the BO and VO zones in the Eagle Ford play are 4.3, 5.0, and 5.1 $gCO_2e/MJ$, respectively. Comparing with other known conventional and unconventional crude production where upstream GHG emissions are in the range 5.9–30 $gCO_2e/MJ$, oil production in the Eagle Ford has lower WTR GHG emissions.

## 1. INTRODUCTION

A rapid increase in horizontal drilling and hydraulic fracturing (HF) in shale and "tight" formations in the United States that began around 2000 has resulted in record increases in oil and natural gas production. Most of this production is from seven significant shale plays: the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian, and Utica plays. Oil and shale gas produced from these low-permeability geological formations are among the so-called "unconventional" or continuous reservoirs, which also include oil shale and coal bed methane. Oil and gas production in the Eagle Ford shale has steadily increased since 2010. The Eagle Ford (illustrated in section 1 of the Supporting Information (SI)), is the largest tight oil producing region in the United States since 2012. Compared with the other oil-rich shale plays such as the Bakken and Permian, the Eagle Ford is gas-rich, producing almost equal amounts of oil and gas on an energy basis.[1] The Eagle Ford is also highly heterogeneous, with different zones being highly gas-rich or very oil-rich. By the summer of 2015, Eagle Ford oil and gas production reached 1.7 million barrels per day (bbl/day) and 7.3 billion cubic feet per day (Bcf/day), respectively, before production decreased due to low oil and gas prices (Figure 1, left). New-well production has steadily increased for oil since 2007 and almost doubled for gas production between 2012 and 2015 (Figure 1, right).

Unlike conventional oil production where vertical wells are drilled and oil (and a small amount of associated gas) are brought to the surface via natural pressure, water drive, or steam or $CO_2$ stimulations, HF is an oil and gas well completion technique in which horizontal drilling is used to increase the well-bore contact area with shale source rocks. Fracturing fluids, consisting of water (≥90%), a proppant material, and various chemicals, are injected through perforations in the borehole at sufficient pressure to promote fracturing of the rock or expansion and extension of existing fractures. This allows fluids to flow out into the fractures when HF pressure is relieved.[2] Studies have examined the oil and gas production potentials in the Eagle Ford region,[1,3−5] climate impacts associated with methane leakage,[6] and impacts on water use.[7,8] However, little information exists about the energy intensity and upstream greenhouse gas (GHG) emissions associated with oil and gas production in the Eagle Ford compared with crude oil production from conventional and other unconventional reservoirs.[9−12]

The goal of the present study is to analyze oil and shale gas production in the Eagle Ford play from the period of 2010

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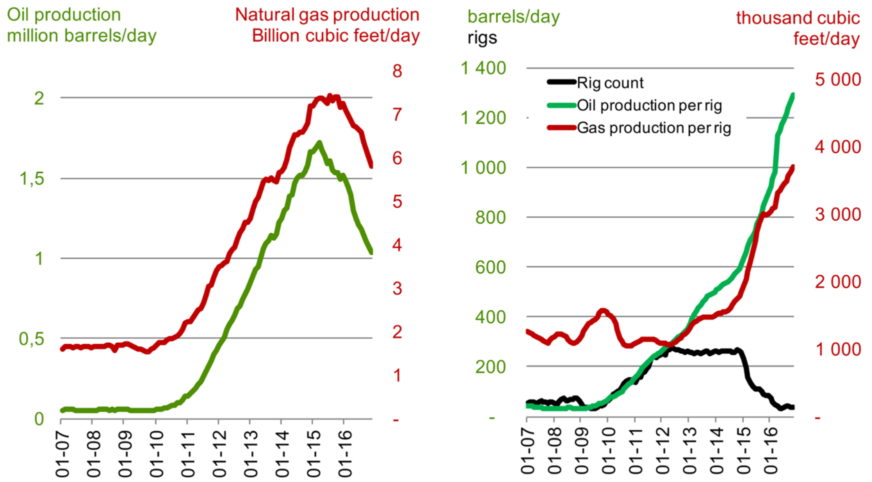


**Figure 1.** Oil and gas production in the Eagle Ford play, 2007−2016. In each panel the primary and secondary *y*-axes have roughly the same total energy content. Left: Total production. Right: New-well production and monthly rig counts. Data source: EIA[1]

through 2013 and to calculate energy consumption and GHG emissions associated with oil and gas extraction. We summarize our data collection and modeling methods in section 2. In section 3, we present results of per-well productivities, energy intensities, and GHG intensities. We discuss the results and implications in section 4.

## 2. DATA AND METHOD

We first describe data sources and methods for estimating current and future production volumes (section 2.1), well characteristics and operation and liquids transport assumptions (section 2.2). In section 2.3, we briefly describe the open-source drilling and fracturing energy estimation tool, GHGfrack model[13,14] and oil production greenhouse gas emissions estimator (OPGEE) model,[15] that estimates energy consumption for drilling, operating, and processing, and fugitive and flaring emissions. We describe in section 2.4 the greenhouse gases, regulated emissions, and energy use in transportation (GREET) model for modeling the life cycle GHG emissions of oil and shale gas production in the Eagle Ford.

### 2.1. Liquids and Gas Production Methods and Volumes.

*2.1.1. Production and Processing Methods.* A stimulated reservoir, as in the Eagle Ford formation, can produce liquids and gas via natural lift "if reservoir pressure is higher than the pressure exerted by a full column of a single-phase well-bore fluid, and the fluid flows to the surface if the flow path is unobstructed."[16] As pressure in the formation decreases, liquids and gas are produced through downhole pumping, gas lifting, and electric submersible pumps (ESPs).[16−18] Once liquids and gas are lifted out of the ground, a heater/treater is used to break oil/gas/water emulsions in the oil wells.[19] Condensate liquids contain a relatively high percentage of light and intermediate components, which can be separated from entrained water easily using a stabilizer because of the lower viscosity and greater density difference with water.[20,21]

Strict pipeline limitations on $H_2S$, $CO_2$, moisture, and $N_2$ require operators to clean produced gas. Amine acid gas removal is performed as part of gas processing to remove $H_2S$ and $CO_2$ from produced gas. A glycol dehydration unit is used for moisture removal. Given maximum heat capacity limitations, operators must often apply a Joules−Thompson unit to remove heavy components or natural gas liquids (NGL). In addition, a nitrogen scavenging unit is used if needed for nitrogen removal.[22] Conder and Lawlor[23] suggest that the gas composition (mol %) for the Eagle Ford is ∼66% methane, 16% ethane, 8.5% propane, and 2.7% butane, and the heating value is 1410 Btu/(standard cubic feet (scf)).

*2.1.2. Liquids and Gas Production Volumes.* We compiled, corrected, and processed IHS well-based monthly data for 11,314 wells in the Eagle Ford. Production data included years 2009 through 2013 (8,218 wells). HF water and proppant use was reported for 8,301 wells from 2009 to 2013. Well test data were compiled from 2009 to 2014 for initial tests (11,298 wells) and follow-up tests (3,430 wells).[8] Data processing included several stages of cross-checking, outlier removal, and analyses that are discussed in greater detail in Ghandi et al.[24] IHS production data include monthly per-well production data for liquids ((bbl/month)/well), gas ($10^3$ $ft^3$ or (Mcf/month)/well), and water ((bbl/month)/well) for 2009−2013. All hydrocarbon production in the liquid state at the wellhead is reported as liquids (which includes crude and lease condensate), and all gas is reported as unprocessed gas production (known as gross production, which contains dry gas and condensate that is separated in subsequent processing plants). The database also includes well characteristics, such as depth—total driller (total length drilled), depth—true vertical, and length of horizontal lateral section.

After a well is completed, initial well tests are conducted to measure the initial flow rate of oil (bbl/day per well), condensate ((bbl/day)/well) and gas (Mcf/day per well), and the properties of the fuels (e.g., API gravity, a measure of specific gravity of crude oil or condensate in degrees), etc. [Note that IHS defines condensate as "liquid hydrocarbons that are separated from gas during production" (source, https://penerdeq.ihsenergy.com/dynamic.splashscreen/documents/USDC.pdf); note that the EIA defines lease condensate as "light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. They are mostly pentanes and heavier hydrocarbons and normally enter the crude oil stream after production" (source, http://www.eia.gov/tools/glossary/index.cfm?id=Lease)] For a subset of wells, data on follow-up well tests were collected, including flow rate and cumulative production of liquids and gas after well completion over time periods ranging from 1 to 1719 days (∼4.7 years). In all, 96% of wells reported initial test results for oil API gravity. An additional 31 wells reported follow-up oil API gravity, which is treated as initial oil API gravity; 33% of wells reported gas gravity, and 24% (2754 wells) reported condensate gravity.

Water and proppant use are derived from IHS and FracFocus databases after a comprehensive data verification process.[8,24] These data refer to the amount of water and proppant used for HF up to the completion (before the start of production) of the wells in the Eagle Ford.

*2.1.3. Characteristics of Production Zones.* We adopt the same zone categorization scheme as that of Scanlon et al.[8] that separates the Eagle Ford into four production zones: black oil (BO), volatile oil (VO), condensate (C), and gas (G) zones. The initial gas-to-oil ratio (GOR) is the ratio of natural gas that a well produces to oil, expressed as thousand cubic feet per barrel—Mcf/bbl—during production months 2 through 4.[8,25,26] The range of GOR ratios and number of wells in each of the four production zones are summarized in SI Table S1. Between 2009 and 2014, the majority of wells (79%) were located in oil-rich


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BO and VO zones with GOR < 10,000 due to more favorable economics in liquids-rich regions.

*2.1.4. Estimated Ultimate Recovery.* As defined by the EIA,[27] the estimated ultimate recovery (EUR) is "the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30 year well lifetime." Significant variability exists for production decline curves and the associated EURs for individual wells within individual plays, and even within discrete sections of plays (i.e., counties and the level of aggregation used by EIA as a basis for projections of overall production totals both for oil and for NG).[27] For many wells in shale plays, nearly 50% of the EUR is produced within 3 years. EIA EUR estimates based on 2008−2013 oil and gas production in Eagle Ford by county is presented in Tables S2 and S3.

Gong[3] and Gong et al.[25] delineate eight production zones in the Eagle Ford on the basis of geology, production indicators, and fluid types. They used a Markov chain Monte Carlo method to develop probabilistic decline curves to forecast reserves and resources in the Eagle Ford. Individual well reserves and resources were estimated and then aggregated probabilistically within each production zone and arithmetically between production zones. The results are shown in Figure S3. Compared with EIA's estimated EURs, estimates of oil EURs by Gong[3] are similar in oil producing zones but consistently higher in gas-rich zones, and gas EURs estimates by Gong[3] are several times higher than EIA's in gas-rich zones.

EUR estimates represent one of the largest sources of uncertainty in the overall characterization of a well.[8,25] To be conservative, we adopt Gong's estimates of EURs by matching the zone definition in Scanlon et al.[8] with the locations of the wells (Table S4). Because the focus of the study is on energy intensity of oil production, we only consider oil EURs in this study. Note that EUR estimates are based on fitting models to historical data, while the actual extraction decision, however, is based on a combination of the geological factors plus economic considerations. For example, if operators decide to stop producing after well productivity declines below a certain level, then the well would not reach its full oil and gas EUR potentials.

**2.2. Liquids and Gas Processes and Transport.** Here we briefly review parameters related to flaring, venting, and extraction loss. We also characterize transportation methods.

*2.2.1. Flaring, Venting, And Extraction Loss.* Once drilling and other well construction activities are finished, a well must be completed in order to begin oil and gas production. The completion process "requires venting of the well for a period of time to remove mud and other solid debris from the well, to remove any inert gas used to stimulate the well (such as $CO_2$ and/or $N_2$), and to bring the gas composition to pipeline grade." (p 22 of ref 28). The Texas Railroad Commission (RRC)[29] reports data on flared/vented gas from 2013. These include monthly total flared/vented gas from gas wells and casinghead gas as reported for RRC Districts 1, 2, and 4, which represent the three main Eagle Ford districts. [Casinghead (oil well) gas is "natural gas produced along with crude oil from oil wells; it contains either dissolved or associated gas or both." (source, http://www.eia.gov/dnav/ng/tbldefs/ng_prod_sum_tbldef2.asp)] The average monthly flared/vented volume by the liquids production for oil and gas wells were calculated separately, suggesting a flaring-/venting-to-liquids ratio of 123 scf/bbl for oil wells and 90 scf/bbl for gas wells, as summarized in Table S5. We apply the oil wells ratio to BO and VO zones, and the gas wells ratio to C and G zones. In 2013, 81% of flared/vented gas was casinghead gas. Variations in flaring-/venting-to-liquids ratios are smaller between gas wells than between casinghead gas.

It has been suggested that, in the Eagle Ford, gas vented during the completion process is usually flared (p 22 of ref 28). To obtain a more precise estimate of flared vs vented gas, we extracted data from EPA GHG Reporting Program Data Sets.[30] These data for 2013 well completions include flaring-related $CO_2$ as well as methane emissions for oil and gas wells. The results are shown in Table S6; we found that, in oil wells, 87.3% of methane was flared, whereas, in gas wells, 99.6% of methane was flared. The total flaring and venting $CO_2$ and methane emission rates per completion are shown in the far-right column in Table S6.

We do not have estimates of operations-related fugitive emissions. EIA defines "extraction loss" as shrinkage of volume due to removal of natural gas plant liquids (NGPL), which is not lost but removed and sent to market. The reduction in volume of NG is due to the removal of NGPL constituents (e.g., propane, and butane) at NG processing plants. The average extraction loss-to-liquids ratio across the districts is 1127 scf/bbl using the data from the Railroad Commission of Texas[22] Table S7 shows extraction loss in the Eagle Ford districts and the overall extraction loss to liquids ratio.

*2.2.2. Transport.* Below we briefly describe the modes of transportation and the average transport distance for Eagle Ford liquids production. These assumptions are summarized in Table S10, and detailed documentation of specific transportation routes and distances can be found in Ghandi et al.[24]

*Barge.* Barges are used to transport crude or refined products along the following routes: Corpus Christi−Houston, Victoria−Houston, and Corpus Christi−U.S. Northeast. The weighted average distance is 568 miles. About 20% of Eagle Ford crude oil is transported via barge.

*Pipeline.* The total distance covered by the currently existing pipeline from the Eagle Ford, on the basis of a combination of data from the EIA Energy Mapping System and Sternberg and Kovacs,[31] is 462 miles, and pipeline transport accounts for about 65% of local Eagle Ford production. We are uncertain about the average pipeline transport distance; therefore, 462 miles is used as a conservative estimate.

*Rail.* The average distance that Eagle Ford crude is transported by rail is assumed to be 200 miles; rail accounts for about 35% of local production.

*Truck.* The average distance that Eagle Ford crude is transported by truck is assumed to be 90 miles; 100% of local production is transported via truck to nearby refineries, or to pipeline terminus or other transportation sites.

**2.3. Modeling of Energy Use, Energy Intensity, And Fugitive Emissions.** OPGEE version 1.1 Draft D[15] was used as the basis for the Eagle Ford upstream production energy intensity and GHG emission analysis. OPGEE is an engineering-based life cycle assessment (LCA) tool for estimating GHG emissions from production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery entrance gate. More detailed documentation of the OPGEE model is given by El-Houjeiri et al.,[15] and an updated version of OPGEE for tight oil production is discussed in greater detail in Brandt et al.[14]

The following well-specific data are taken from the above-described input variables for each well−month combination: completion date and production month; true vertical depth of well; liquids production (crude + lease condensate, per month); gas production (as producing GLR); water production (as percent water); and crude API gravity. A total of 144,924 runs in OPGEE were performed, with one model run performed for each well−month combination in the data set. A total of 11,314 unique well identifiers were included in the data set, though obviously not all wells reported data for all months.

Drilling energy requirements were computed using the GHGfrack model[14,32] for a typical Eagle Ford casing plan and the given well geometry in the IHS data sets. GHGfrack reports results as energy use (diesel fuel) for top-drive torque, mud pump work, and fracturing water pumps. Drilling and development diesel energy use is diesel fuel use in drilling and fracturing, divided by EUR for the well. Production and extraction energy use represents a sum of all on-site energy use for lifting of fluids from the formation. Surface processing uses thermal energy from natural gas for crude separation (heater/treater) and stabilization, amine reboiler, glycol reboiler, and demethanizer. Surface processing also uses electricity for amine treater pumps and air coolers, glycol pumps, and water treatment.

Fugitive emissions were calculated once for a typical Eagle Ford well, and all wells have fugitive emissions set equal to this value for all operating months. Lack of well-specific data on parameters relevant to fugitive emissions suggests that performing well-specific fugitive calculations is not justified. The fugitive emissions rate was assumed to be 36.5 scf/bbl across all wells (or 1.3% of the median GLR of >2500 scf/bbl) using the default value in OPGEE[15] which is based on standard emissions factors from the U.S. EPA as well as some data


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**Table 1. Eagle Ford Liquids and Gas APIs and Well Property Summary (Averages Across All Zones and All Years, 2009−2013)**

| property | obs | median | mean | std dev | min | max | units |
|---|---|---|---|---|---|---|---|
| oil API gravity | 11314 | 46.2 | 48.0 | 8.59 | 27 | 94 | (deg API) |
| condensate gravity | 2754 | 58 | 57.7 | 5.46 | 34.8 | 79.4 | condensate gravity |
| gas gravity | 3420 | 0.73 | 0.73 | 0.07 | 0.56 | 1.44 | gas gravity |
| depth total driller | 11314 | 15560 | 15580 | 1750 | 5330 | 21910 | (ft) |
| proppant used | 11314 | 4290 | 4770 | 1900 | 3.41 | 19800 | (1000 lb) |
| depth true vertical | 11314 | 10050 | 9980 | 1760 | 2760 | 15600 | (ft) |
| water used | 11314 | 4304 | 4680 | 1820 | 53 | 22600 | (1000 gallon) |
| fracture pressure | 11314 | 9040 | 8980 | 1590 | 2480 | 14000 | (psi) |

from California. The venting rate due to flowback emissions (which is computed in addition to the operational well-default fugitive emissions rate above) was 13% of the flowback gas volume, apportioned per barrel of EUR (median value is very small at ∼1 scf/bbl) (Table S8).

Fracturing flowback gas volumes are either flared or vented in the Eagle Ford, and these represent possible emissions sources. Flowback volumes are computed using a modified version of the method of O'Sullivan and Paltsev.[33] Initial production test results from the above data sets report initial gas production rates. This initial gas production rate (per day) is multiplied by an effective flowback period of 3 days. Flowback volumes increase as the well bore clears, and O'Sullivan and Paltsev[33] assume 4.5 days of effective flowback (9 days of flowback, linearly increasing from 0 to the initial production rate). Later analysis by the Environmental Defense Fund[34] suggests that 3 days of effective flowback may be more appropriate. We selected a 3 day flowback period so as to not overestimate impacts, though flowback volumes are small enough that this is not a material driver of emissions (Table S7).

The flaring rate is derived from an aggregate of reported per-bbl flaring rate, which is determined each month, along with 87% of the flowback gas, apportioned per barrel of EUR. A single per-bbl flaring intensity of 123.5 scf/bbl was generated using the above reported regional data for the Eagle Ford region, because well-specific or monthly flaring data were not available. The flowback flaring volumes are, in comparison, small over the life of the well, with a median rate of 10.7 scf/bbl and a mean rate of 16.6 scf/bbl. For both flowback and per-bbl flaring, a default flaring methane destruction efficiency of 99% was used in all cases.

Based on the above-described inputs, OPGEE generates the following output variables, and the results are summarized in section 3: NG net sale (MMBtu/day); NGL net sale (MMBtu/day); drilling and development (diesel, MMBtu/day); production and extraction (NG, MMBtu/day); surface processing (NG, MMBtu/day); surface processing (electricity, kWh/day); flaring rate (MMcf/day); flaring efficiency (%); fugitives rate (constant for all wells, scf/bbl).

**2.4. Modeling of GHG Emissions and GHG Intensity.** To model GHG emissions associated with oil and shale gas production in the Eagle Ford with the GREET model, process fuel consumption by fuel type, flaring intensity of produced gas, flaring efficiency, fugitive produced gas emissions, and chemical composition of produced gas were calculated from the OPGEE model and used as input values in the GREET model.[35]

We allocate process fuel consumption, flaring, and fugitive emissions to energy products by assuming that the utility of the energy embedded in oil, NG, and NGL is the same for their respective end users, as shown in eq 1. There is no universally mandated allocation method. Other allocation methods, such as market-value-based allocation, could be used to allocate energy use, GHG emissions, and water use to the energy products on the basis of their market values.

$$F_{i,j,x} = F_{i,j}\left(\frac{E_{j,x}}{E_{j,\mathrm{oil}} + E_{j,\mathrm{NG}} + E_{j,\mathrm{NGL}}}\right)/E_{j,x} \quad (1)$$

where $i$ = process fuel consumed (Btu or MMBtu); $j$ = well identification; $x$ = energy product as oil, NG, or NGL; $F_{i,j,x}$ = fuel $i$ consumption rate (Btu or MMBtu/(MMBtu of product $x$)) for well $j$ and energy product $x$; $F_{i,j}$ = monthly fuel $i$ energy consumed (Btu or MMBtu/month) for well $j$; and $E_{j,x}$ = monthly energy production of $x$ (MMBtu of product $x$/month) for well $j$ where $x$ is either oil, net NG sale, or net NGL sale calculated from OPGEE.

Note that $F_{i,j,x}$ is the same regardless of the energy product (oil, net NG sale, or net NGL sale) produced, and $F_{i,j}$ is simply the sum of the fuel $i$ consumption rate multiplied by the energy produced, i.e., $F_{i,j} = \sum_x (F_{i,j,x} \times E_{j,x})$ or $F_{i,j} = F_{i,j,x} \sum_x E_{j,x}$. The equation is identical for calculation of flaring and fugitive emission rates (in scf/(MMBtu of product $x$)).

The equation for water consumption is slightly different as, unlike fuel use, flaring, and fugitive emissions, the HF water use has not been normalized to total lifetime production. Thus, the water consumption rate is shown in

$$W_{j,x} = W_j\left(\frac{\mathrm{EUR}_{j,x}}{\mathrm{EUR}_{j,\mathrm{oil}} + \mathrm{EUR}_{j,\mathrm{NG}}}\right)/\mathrm{EUR}_{j,x} \quad (2)$$

where $W_{j,x}$ = water consumption rate (gal/(MMBtu of product $x$)) for well $j$ and energy product $x$; $W_j$ = HF water use (gal) for well $j$; and $\mathrm{EUR}_{j,x}$ = EUR of energy product $x$ (MMBtu of product $x$) for well $j$ where $x$ is either oil or NG.

Note that the NG in $\mathrm{EUR}_{\mathrm{NG}}$ in eq 2 is the raw unprocessed NG that is technically recoverable from each well, whereas the net NG sale and net NGL sale in eq 1 are energy products calculated from OPGEE on the basis of the reported monthly production of raw NG.

We report the fuel consumption rate, flaring, and fugitive emission rate, and water consumption rate for oil production zones (BO and VO zones) and gas production zones (C and G zones) separately.

Wide variations in energy use and production among the thousands of wells are observed. To account for the effect of this variability on the estimation of GHG emissions with GREET, we developed probability distribution functions (PDFs) for the major parameters, using 104,345 well−month observations for wells located in the BO and VO zones and 27,889 well−month observations for wells located in the C and G zones. The approach is described in section 9 of the SI. We apply the regression formula developed for estimating the overall refinery energy efficiency and the relative refinery energy requirements for specific petroleum products by Elgowainy et al.[9] to calculate the GHG emissions associated with refining of crude oil from the Eagle Ford.

## 3. RESULTS

We report results from analyzing the data including production rate and characteristics of liquids and gas (section 3.1), well characteristics, and water use (section 3.2). We then report our model estimates of energy use and GHG emissions (section 3.3).

**3.1. Liquids and Gas Production and Characteristics of Products.** Table 1 includes a summary of key Eagle Ford fluid properties well characteristics. The annual liquids and gas production volumes are reported in Table S11. In 2013, liquids production reached 0.93 million bbl/day and gas production reached 3.86 Bcf/day. We calculate "producing gas-to-liquids ratio (GLR)" as the monthly produced gas ((scf/well)/month) to monthly produced liquids ((bbl/well)/month) for each well. The monthly well-based GLR (scf/bbl) is shown in Figure 2. The drastic reduction of GLR is consistent with the suggestions that oil and gas production in the Eagle Ford region has shifted



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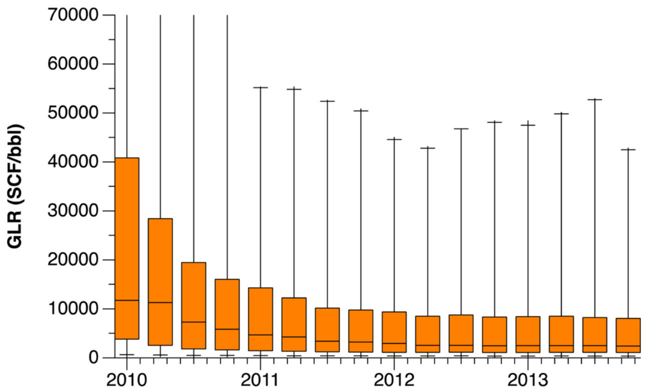


**Figure 2.** Box plots of monthly gas-to-liquids production ratios (scf/bbl) for each well in the Eagle Ford 2010−2013. The box plots show the median, the first, and the third quartile (boxes), and fifth and 95th percentile (whiskers) values, except for the values in 2010, where the 95th percentile values are off-scale.

from "gas-rich regions" to "oil-rich regions" over the years.[5,8,25] The monthly GLRs based on monthly production data for each well by zone are shown in Figure S5. The slopes of the linear regressions represent the average monthly GLR (Mcf/bbl) by zone. The annual liquids and gas productions by zone are reported in Table S12.

The oil flow rate ((bbl/day)/well) from the initial test increased over the years (Figure S4, bottom), whereas the initial gas flow rate decreased over time (Figure S4, top) and the initial condensate flow rate ((bbl/day)/well) remained relatively stable (Figure S4, middle). Between 2009 and 2013, the initial test data indicate that between 27 and 62% of liquids is condensate, and the ratio has remained at ∼30% since 2011.

Figure 3 is a plot of the ratio of follow-up to initial liquids or gas flow rates as a function of days after well completion.

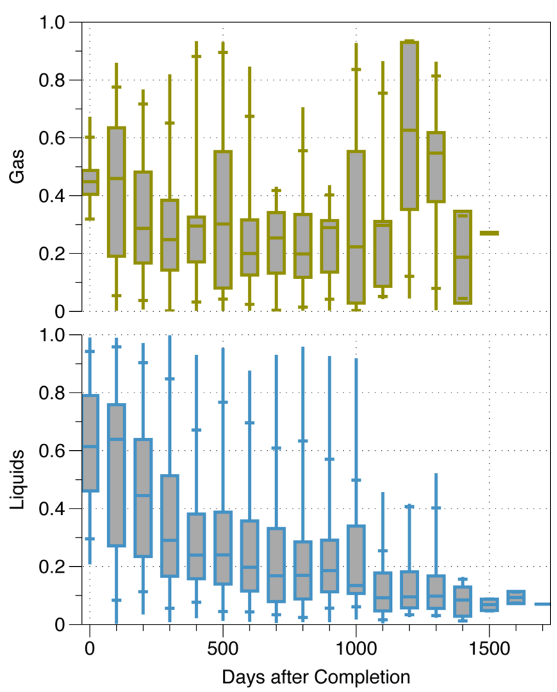


**Figure 3.** Box plots of follow-up test to initial test gas (top) and liquids (bottom) flow rate ratio as a function of days after completion. The box plots show the median, the first and the third quartile (boxes), fifth and 95th percentile (whiskers), and the min and max values (lines).

The liquids flow rate shows rapid declines immediately after well completion and eventually drops to below 10% of the initial flow rate in less than 3 years after well completion (bottom panel). The gas flow rate, however, has not markedly decreased but remains roughly the same as or higher than the initial flow rate (top panel). This finding is consistent with the observations that, for each well, oil production tends to steadily decrease during production, and the GLR increases over the production lifetime.[25]

Figure 4 shows the cumulative liquids and gas production to date compared with the estimated EUR by Gong.[3] On average, per-well cumulative production to date is about 30% of the estimated oil EUR and 14% of the estimated gas EUR. The cumulative oil and gas production to date vs estimated EUR by well zone (Figure S6) also shows similar findings: for each producing zone, a greater proportion of oil had been produced to date compared to the estimated oil EUR than gas. As mentioned above, the EUR estimates are based on the geology and the technical assessment of the field properties and technology, while actual extraction also includes economic considerations.

The proportions of the products (oil, condensate, and gas, measured by energy) by producing zone are shown in Table 2. In the BO zone, almost all of the liquids produced are oil (99%). The oil/condensate split is about 60/40 in the VO zone, whereas the majority of the liquids produced in the C and G zones are condensate (98% and 91%, respectively). Because liquids production declined more rapidly than gas production (Table 2), the overall breakdown over the entire production period between 2009 and 2013 is about 52−80% liquids in the BO and VO zones vs 8.5−21% liquids in the C and G zones.

The average API gravity of Eagle Ford liquids is higher (which means lower density, lighter) than that of typical crudes in the U.S. Figure S9 shows the range of API gravity values of Eagle Ford liquids produced by zone type and the corresponding heating values. The API values of liquids are lower in BO and VO zones (with mean values of 42 and 50, respectively, compared with 62 and 58 in C and G zones), with higher corresponding heating values (5.2 MMBtu/bbl in BO and VO zones, compared with 5.0−5.1 MMBtu/bbl in C and G zones). Liquids produced from the oil zone have higher heating values, whereas liquids produced from the condensate zone have the lowest heating values, though the variation is quite small, less than 3%.

**3.2. Well properties and Water Use.** The average length of wells increased ∼50% between 2009 and 2013 (3570 to 5,310 ft/well), while the average depth decreased slightly (10,100 to 9840 ft/well) (Table S13). The average total length drilled has been constant through all years at 15,500 ft, and the average true vertical depth of wells is about 10,000 ft for all years (Table S14).

Table S16 includes the distributions of water use per horizontal lateral length (gal/ft) and proppant use per horizontal lateral length (lb/ft) by year. As shown in Table S16 and Figure S14, water use and proppant use per horizontal lateral length have remained stable in the past several years.

**3.3. Energy Intensity and GHG Emissions.** Figure 5 presents the well-based energy balance of Eagle Ford wells by zone, showing the mean values. Natural gas balance shows the breakdown of NG fugitive emissions, flaring, self-consumption, and NG and NGL net sales calculated by OPGEE. These numbers are listed in Table 3, which shows the mean and median well-based NG production and NG balance


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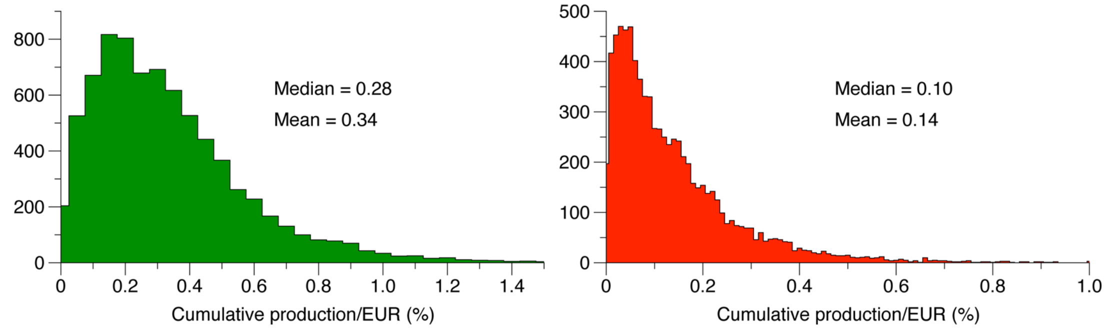


**Figure 4.** Cumulative production to date vs estimated EUR for oil (left) and shale gas (right) production in the Eagle Ford, based on data from Gong.[3]

**Table 2. Relative Contributions of Oil, Condensate, and Gas-to-Energy Content in Initial Test Sampling and Relative Contributions of Liquids and Gas in Total Production**

| | energy (initial test data) (%) | | | total production (%) | |
|---|---|---|---|---|---|
| zone type | oil | condensate | gas | liquids | gas |
| black oil (BO) | 84 | 1 | 15 | 79 | 21 |
| volatile oil (VO) | 37 | 26 | 37 | 52 | 48 |
| condensate (C) | 0.5 | 21 | 79 | 21 | 79 |
| gas (G) | 0.4 | 4.6 | 95 | 8.5 | 92 |

(including flaring, fugitive emissions, self-consumption for production and extraction and surface processing, NG net sale, and NGL sale) calculated by OPGEE. In the BO zone, about 20% of the NG produced is either flared, emitted, or used for self-consumption, and only about 80% is sent to the market; whereas over 94–98% of the NG produced in the VO, C, and G zones is sent to the market as pipeline NG and NGL.

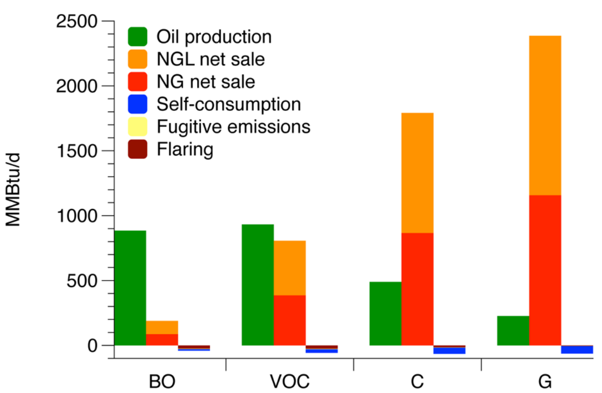


**Figure 5.** Well-based average fossil energy balance of Eagle Ford wells by well zone (2009–2013).

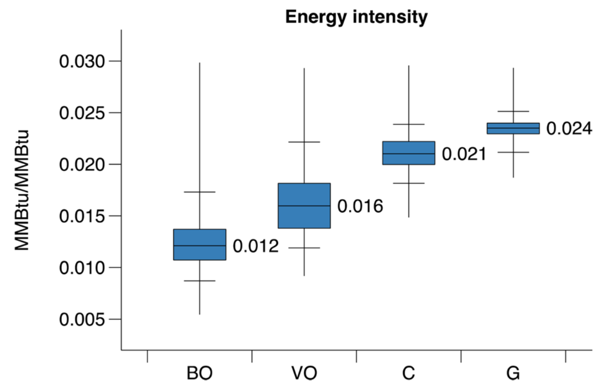


**Figure 6.** Well-based total energy use for oil and shale gas production by zone type. Whiskers show the fifth and 95th percentile values.

Energy intensity is defined as MMBtu of energy (including diesel, NG, and electricity) used for production, extraction, and surface processing per MMBtu of energy produced (including liquids, net NG sale, and net NGL sale). The recovery energy efficiency (1 − energy intensity), process fuel consumption, flaring and fugitive intensities, and water use in the oil zone showed little variation over time between 2010 and 2013 (Figure S15). The same holds for the production in the gas zone. Figure 6 shows that energy intensity tends to increase with higher gas production, as gas production requires more energy use for lifting and processing. The total energy consumed in drilling, extracting, processing, and operating an Eagle Ford well is approximately 1.5% of the energy content of the

**Table 3. Mean and Median Well-Based Oil and Natural Gas Production (MMBtu/d/well) and Natural Gas Balance Calculated by OPGEE and the Shares (in Parentheses) of NG Balances**

| | monthly oil production | monthly gas production | OPGEE calculation | | | | |
|---|---|---|---|---|---|---|---|
| | | | flaring | fugitive emissions | self-consumption | NG net sale | NGL sale |
| median | | | | | | | |
| BO | 594 | 148 | 17 (12%) | 2.1 (1.5%) | 8.1 (5.7%) | 51 (36%) | 63 (44%) |
| VO | 556 | 586 | 15 (2.7%) | 2.0 (0.3%) | 18 (3.2%) | 258 (45%) | 282 (49%) |
| C | 312 | 1410 | 10 (0.7%) | 1.1 (0.1%) | 35 (2.5%) | 659 (47%) | 703 (50%) |
| G | 59 | 1760 | 1.5 (0.1%) | 0.1 (0.0%) | 42 (2.4%) | 831 (47%) | 882 (50%) |
| mean | | | | | | | |
| BO | 884 | 233 | 26 (11%) | 3.1 (1.3%) | 12 (5.2%) | 87 (38%) | 102 (44%) |
| VO | 932 | 868 | 26 (3.1%) | 3.3 (0.4%) | 27 (3.1%) | 386 (45%) | 420 (49%) |
| C | 489 | 1860 | 16 (0.8%) | 1.7 (0.1%) | 48 (2.6%) | 866 (47%) | 925 (50%) |
| G | 226 | 2450 | 4.5 (0.2%) | 0.5 (0.0%) | 58 (2.4%) | 1160 (47%) | 1230 (50%) |


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Table 4. Summary of Energy and Water Use and Other Parameters Associated with Oil or Shale Gas Production (Btu, scf, or gal per MMBtu of Oil or Gas) from Wells Located in the Black Oil and Volatile Oil Zones (Top) And Condensate and Gas Zones (Bottom) in the Eagle Ford Play, 2010−2013, Using the Energy Allocation Method except Where Noted

| unit | recovery energy efficiency (%) | NG use (Btu/(mmBtu of oil)) | diesel use (Btu/(mmBtu of oil)) | electricity use (Btu/(mmBtu of oil)) | flaring intensity (SCF/(mmBtu of oil)) | fugitive intensity (SCF/(mmBtu of oil)) | water use (gal/(mmBtu of oil)) | oil API gravity (SCF/(bbl of oil)) | GLR[b] (SCF/(bbl of oil)) | O/T ratio[c] | NG/T ratio[d] | NGL/T ratio[e] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| weighted av[a] | 98.6 | 13600 | 976 | 140 | 15.4 | 4.6 | 2.30 | 47.7 | 2340 | 0.66 | 0.16 | 0.18 |
| arithmetic av | 98.6 | 13100 | 1020 | 137 | 16.1 | 4.8 | 2.73 | 45.5 | 6030 | 0.69 | 0.15 | 0.16 |
| P1 | 97.5 | 6260 | 167 | 14 | 2.8 | 4.8 | 0.37 | 30.0 | 108 | 0.16 | 0.00 | 0.00 |
| P10 | 98.1 | 8520 | 346 | 50 | 7.0 | 1.1 | 0.66 | 38.0 | 488 | 0.37 | 0.03 | 0.04 |
| P25 | 98.4 | 10200 | 516 | 75 | 11.4 | 2.6 | 1.41 | 41.0 | 906 | 0.53 | 0.07 | 0.08 |
| P50 | 98.7 | 12300 | 811 | 117 | 17.9 | 5.2 | 2.35 | 45.0 | 1680 | 0.74 | 0.12 | 0.14 |
| P75 | 98.9 | 15400 | 1190 | 180 | 20.6 | 6.0 | 3.40 | 49.9 | 3830 | 0.85 | 0.22 | 0.24 |
| P90 | 99.0 | 18000 | 1850 | 237 | 22.2 | 6.4 | 4.84 | 54.8 | 7180 | 0.93 | 0.30 | 0.33 |
| P99 | 99.3 | 24400 | 4460 | 363 | 24.1 | 7.0 | 11.23 | 60.3 | 22800 | 1.00 | 0.41 | 0.44 |

| unit | recovery energy efficiency (%) | NG use (Btu/(mmBtu of NG)) | diesel use (Btu/(mmBtu of NG)) | electricity use (Btu/(mmBtu of NG)) | flaring intensity (SCF/(mmBtu of NG)) | fugitive intensity (SCF/(mmBtu of NG)) | water use (gal/(mmBtu of NG)) | oil API gravity (SCF/(bbl of oil)) | GLR[b] (SCF/(bbl of oil)) | O/T ratio[c] | NG/T ratio[d] | NGL/T ratio[e] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| weighted av[a] | 97.9 | 21500 | 380 | 297 | 3.4 | 1.3 | 0.94 | 60.8 | 19100 | 0.18 | 0.40 | 0.42 |
| arithmetic av | 97.8 | 22300 | 387 | 314 | 3.4 | 1.3 | 0.98 | 60.2 | 699000 | 0.18 | 0.40 | 0.42 |
| P1 | 97.1 | 15600 | 0 | 187 | 0.0 | 0.0 | 0.17 | 46.2 | 4590 | 0.00 | 0.24 | 0.27 |
| P10 | 97.7 | 18100 | 41 | 235 | 0.5 | 0.2 | 0.34 | 53.1 | 8570 | 0.03 | 0.32 | 0.35 |
| P25 | 97.8 | 19400 | 152 | 262 | 1.6 | 0.6 | 0.56 | 58.0 | 12700 | 0.09 | 0.36 | 0.39 |
| P50 | 97.9 | 20800 | 291 | 289 | 3.2 | 1.2 | 0.82 | 61.3 | 19800 | 0.17 | 0.40 | 0.43 |
| P75 | 98.0 | 22400 | 455 | 319 | 4.7 | 1.8 | 1.20 | 63.6 | 41900 | 0.25 | 0.44 | 0.47 |
| P90 | 98.1 | 23400 | 728 | 339 | 6.4 | 2.3 | 1.78 | 65.9 | 157000 | 0.33 | 0.47 | 0.50 |
| P99 | 98.4 | 28400 | 1990 | 414 | 11.6 | 3.4 | 3.11 | 69 5 | 2.07E7 | 0.48 | 0.49 | 0.51 |

[a]Weighted by total output of energy products, i.e., oil. natural gas. and natural gas liquids. [b]Without energy-based allocation applied. [c]Output ratio of oil to total products (i.e., oil. NG, and NGL) by energy content. [d]Output ratio ofNG to total products by energy content. [e]Output ratio of NGL to total products by energy content.



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produced crude and gas in the BO and VO zones, compared with 2.2% in the C and G zones (Figure 6).

Table 4 summarizes the recovery energy efficiency, process energy use by fuel type, the flaring intensity, the fugitive intensity, water use, oil API gravity, GLR, and the O/T ratio for oil or shale gas production in the oil Eagle Ford play from 2010 to 2013.

Table 5 summarizes the well-to-refinery (WTR) GHG emissions and water consumption of gasoline, diesel, and jet fuels.

**Table 5. Well-to-Refinery (WTR) GHG emissions, in $gCO_2e/MJ$, of Gasoline, Diesel, And Jet Fuels Derived from Crude Oil Produced in the BO and VO Zones in the Eagle Ford Play**

| | WTR |
|---|---|
| GHG emissions ($gCO_2e/MJ$) | |
| gasoline blendstock | 4.3 |
| diesel | 5.0 |
| jet | 5.1 |
| water consumption (gal/MMBtu) | |
| gasoline blendstock | 2.5 |
| diesel | 3.0 |
| jet | 3.0 |

Figure 7 summarizes the detailed breakdown of upstream WTR GHG emissions for gasoline derived from crude oil produced

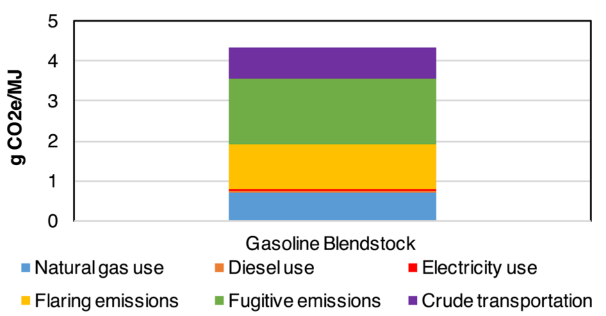


**Figure 7.** Detailed breakdown of well-to-refinery (WTR) GHG emissions for gasoline derived from crude oil produced in the BO and VO zones in the Eagle Ford play.

in the BO and VO zones. The largest contribution to WTR GHG emissions comes from fugitive emissions (38%), followed by flaring (26%), crude transport (18%) and natural gas use (16%).

## 4. DISCUSSION

The WTR GHG emissions associated with crude oil and gas production in the BO and VO zones (which constitute 79% of the wells and 90% of total liquids production between 2009 and 2013, inclusive) is 4.3 $gCO_2e/MJ$ for gasoline, and 5.0 $gCO_2e/MJ$ and 5.1 $gCO_2e/MJ$ for diesel and jet fuel, respectively. Oil production from Bakken has slightly higher WTR emissions (typical value, 8−10 $gCO_2e/MJ$,[36,37] consisting of nonflaring wells of 3.5 $gCO_2e/MJ$ and 13 $gCO_2e/MJ$ for flaring wells).[37] Comparing with WTR GHG emissions associated with conventional and unconventional crude production, including the U.S. average of 6−8 $gCO_2e/MJ$,[38,39] California of ≈15 $gCO_2e/MJ$,[40] Canadian oil sands in situ production of 15−30 $gCO_2e/MJ$, and mining projects of ≈12−25 $gCO_2e/MJ$,[41−46] oil production in the Eagle Ford has relatively low WTR GHG emissions (Figure 8). In Figure 8, we only report single estimates

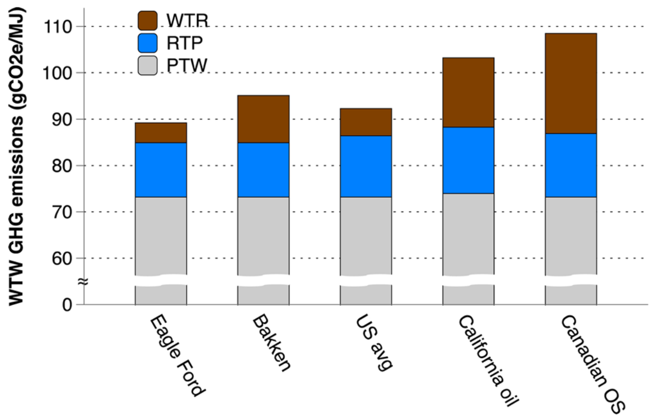


**Figure 8.** Comparison of well-to-wheel GHG emissions ($gCO_2e/MJ$, LHV) for gasoline from selected conventional and unconventional crude fuel pathways, including Eagle Ford (this study) and Bakken oil production,[37] U.S. average crude,[11] California crude,[40] and Canadian oil sands.[11] WTR, well to refinery; RTP, refinery to pump; PTW, pump to wheel.

from these studies since the reported ranges across studies are not directly comparable: some report ranges using scenarios based on different assumptions; others use Monte Carlo simulations to represent ranges of uncertainties. Compared with the other stages of the life cycle, which include refinery, transport, and combustion emission, WTR emission is only 5−6% of the total emissions for conventional crude.[11,24]

Figure 9 compares water use from oil extraction/HF with and without the consideration of EUR and the consideration of

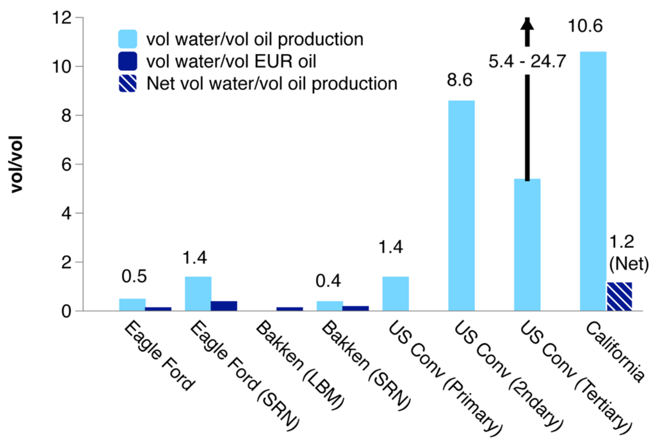


**Figure 9.** Comparison of water use for crude oil extraction (vol/vol oil production or vol/vol oil EUR) from various sources, including Eagle Ford from this study and Scanlon et al.[8] (SRN), Bakken,[8,36] U.S. conventional crude (cited in Tiedeman et al.[2]), and California crude[2] (including total water use and net water use where recycled produced water is deducted from the total water use).

net water use when a large amount of produced water has been reused to reduce the overall water use. In general, water use intensities are lower for HF oil production compared with conventional oil production.

The largest uncertainty in this study results from the EUR estimates. Average per-well cumulative production to date is about 30% of the estimated oil EUR and 14% of the estimated gas EUR from Gong et al.[25] (Figure 4). If we allocate energy use and GHG emissions to actual production as opposed



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to EUR, then the values would be at least 3 times higher (1/0.3, as we ignore gas EUR) than our estimates here.

A future extension could be to perform spatially resolved GHG intensity measurements. For example, high-resolution nighttime flaring data are now available for the Eagle Ford region.[6,47] With effort toward designing spatial alignment algorithms, these images of flares could, in principle, be aligned with producing wells to provide much more detailed and granular flaring estimates. This would be a major improvement over the current state-of-the art in remote-sensing-based flaring analysis.

Flaring and fugitive emissions currently constitute over 64% of the upstream emissions from oil producing wells (Figure 7). In June 2016, the U.S. Environmental Protection Agency (EPA) published proposed regulations aiming to reduce methane emissions from oil and gas production and operations (known as Subpart OOOOa).[48] The new rules will include methane emissions from hydraulically fractured oil well completions and fugitive emissions at oil well sites and compressor stations (gas well completions and fugitive emissions are already regulated), and pneumatic pumps and controllers. The proposed regulations, though still yet to be adopted at the time of the publication, can potentially reduce upstream emissions.

## ■ ASSOCIATED CONTENT

### Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.energyfuels.6b02916.

> Additional information regarding Eagle Ford geographical location, EUR, flaring, venting and extraction loss, transport distances, oil and gas producing volumes, product and well characteristics, water and proppant use, energy consumption, and lifecycle GHG emissions (PDF)

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### Notes

The authors declare no competing financial interest.

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