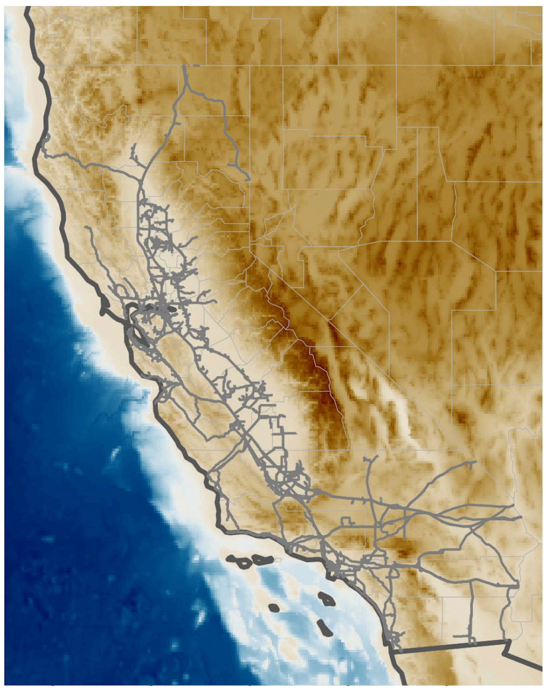
# APPENDIX E
# Spatial Inventory of Greenhouse Gas Emissions from California Natural Gas Infrastructure

## *Final Spatial Emission Mapping Report*



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ELECTRIC POWER RESEARCH INSTITUTE

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# Spatial Inventory of Greenhouse Gas Emissions from California Natural Gas Infrastructure:

## *Spatial Emission Mapping Report*

Draft Report

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# Summary

We present a spatially explicit mapping of major ($CO_2$, $CH_4$, $N_2O$) greenhouse gas emissions from natural gas activities across California. We estimate emissions for several primary sectors related to natural gas infrastructure that are consistent with the current Environmental Protection Agency's inventory. These primary sectors are oil and gas production, processing, transmission, and distribution defined in the EPA's greenhouse gas inventory, and represent emissions from fugitive leaks, vents and flaring ("non-fuel-combustion") activities. We also estimate spatially disaggregated emissions specific to the post-meter consumption of natural gas, which has not been reported previously. Emissions of $CO_2$ and $CH_4$ were estimated for all primary sectors and post-meter consumption, while the $N_2O$ information only includes post-meter consumption emissions due to lack of data. Using a consistent framework where same activity data and methodology are used, we compare $CO_2$ and $CH_4$ emissions specific to the petroleum and natural gas systems in California. Using the 2018 US EPA inventory we estimate 2016 statewide annual non-combustion (i.e. fugitive, vented, flared) $CO_2$ and $CH_4$ emissions for the primary sectors of 1.42 (1.06 – 1.88 at 95% confidence) and 4.31 (3.58 – 5.08) Tg $CO_2$ equivalent (eq), respectively, using a 100-yr global warming potential (GWP) of 25 g $CO_{2eq}$/g $CH_4$. Thus, mitigating climate change from fugitive and vented natural gas related activities would be most effective if focused on reducing $CH_4$ emissions rather than $CO_2$. However, the total emitted $CO_2$ including fuel combustion is roughly an order of magnitude larger than $CH_4$ in California. When the post-meter consumption emissions are included, the total $CO_2$ emissions (97.2 Tg $CO_2$) become substantially larger than those of $CH_4$ (5.7 Tg $CO_2$eq), suggesting that reduction of combustion emissions remains an important goal. We find this study's $CH_4$ emission estimates for the primary sectors are ~50% lower than those from previous similar studies. This discrepancy is attributed to the reduction in the emission factors used by EPA, as well as a recent decrease in non-associated (dry) gas production by a factor of 3. Further studies in expanded regions including California's San Joaquin Valley, a major oil and gas production region, will help verify emissions from the natural gas and petroleum systems.

# 1. Introduction

US dry natural gas production has increased by more than 50% since 2007 (US EIA, 2019a) and is expected to increase further in the coming years. While the replacement of coal in combustion sources with natural gas has the potential to reduce total greenhouse gas (GHG) emissions, emissions during production and distribution could reduce these benefits (Alvarez et al., 2012). National-scale estimates of methane ($CH_4$) emissions as a % of natural gas produced vary. Burnham et al. (2011) estimate emission rates of 0.97 - 5.47% for conventional gas production and 0.71 to 5.23% for shale gas production. On the other hand, using measurements at 190 onshore sites, Allen et al. (2013) estimate emissions from the natural gas production to be only 0.42% of total production. In a more recent study, using facility-scale measurements Alvarez et al. (2018) estimate production emissions are 1.1 – 1.7% of the annual US natural gas production. At the regional scale, the emission rates (central estimates) vary significantly ranging from 0.4% to more than 9% (Karion et al., 2013, Pétron et al., 2014, Peischl et al., 2015, Barkley et al., 2017). These studies show that reducing uncertainty in the quantification of the climate benefits of natural gas remains a challenge and requires continuous efforts based on measurements.

In California, accounting for GHG emissions from the natural gas and petroleum systems is needed because emissions are regulated by state laws and policies (Legislative Information, 2006). In 2016 California's legislature passed Senate Bill 32, which requires GHG emissions to be 40% below 1990 levels of the total GHG emissions by 2030 (Legislative Information, 2016). Moreover, California's Executive Order S-3-05 establishes a GHG emission target of reducing state GHG emissions to 80% below 1990 levels by 2050 (Office of Governor, 2005). California's natural gas consumption accounts for 8% of the US total, while producing a large volume (~170 × $10^6$ barrels in 2018, similar production to Alaska) of crude oil and associated gas each year (EIA, 2019b). Much of California's oil production involves enhanced recovery with steam injection, while hydraulic fracturing was reported for a subset of recent wells (California Council on Science and Technology, 2015). Considering California's large oil and gas production and consumption, it is essential to account for GHG emissions from the natural gas and petroleum sector to verify the implementation of recent legislation to limit California's contribution to global climate change.

As part of efforts to understand GHG emissions from California's natural gas and petroleum systems, Jeong et al. (2014) developed a spatially explicit $CH_4$ emissions inventory from oil and gas production, processing, transmission and distribution. At the national scale, Maasakkers et al. (2016) developed a gridded inventory of US anthropogenic methane emissions including the oil and gas sector and found comparable results for California to those from Jeong et al. (2014). However, recent top-down studies indicate that fugitive natural gas emissions in urban areas are likely higher than those estimated by bottom-up inventories. In the Los Angeles metropolitan area, top-down studies reported that there are up to ~70% higher than bottom-up natural gas related emission estimates, with much of those emissions associated with distribution or consumption (Wennberg et al., 2012; Peischl et al., 2013; Hopkins et al., 2016; He et al., 2019). Similarly, in the San Francisco Bay Area, using multi-species measurements including ethane Jeong et al. (2017) estimated that natural gas $CH_4$ emissions are 1.5 – 2.4 times higher than the prior emission based on Bay Area Air Quality Management District's inventory. Using measurements in 75 California homes, Fischer et al. (2018) reported that emissions from residential natural gas account for ∼15% of California's natural gas-related $CH_4$ emissions, suggesting that leak repair and improvement of combustion appliances can help California meet its 2050 climate goals.

Building upon previous studies, we provide an updated spatially explicit bottom-up estimate of $CH_4$ emissions from several primary sectors (oil and natural gas production, transmission, processing, distribution), and post-meter natural gas consumption as well as $CH_4$ associated with petroleum production and refining in California. Using unified methods and datasets, we also develop gridded natural gas-related $CO_2$ emissions while we generate gridded nitrous oxide ($N_2O$) emissions based on the US Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP). This work improves on the spatial representation of the distribution and consumption sectors by developing a high-resolution (1-km) natural gas consumption map across California, whereas previous work (e.g., Jeong et al., 2014) used 10-km moderate-resolution population density as a proxy for natural gas consumption. The methods section details the data and emission factors used to develop the spatially explicit emissions inventory. The results and discussion sections describe estimated emission totals by sector and compare this work to other bottom-up inventories and top-down analysis results.

# 2. Methods

## 2.1 Overall Approach

We estimate spatially explicit GHG emissions for the natural gas and petroleum systems from four primary sectors for 2016: petroleum and natural gas production, natural gas processing, natural gas transmission, and distribution. The EPA's Greenhouse Gas Inventory (GHGI) estimates GHG emissions for these primary sectors under the category of the natural gas and petroleum systems. To be consistent with the EPA GHGI and previous studies (Jeong et al., 2014; Maasakkers et al., 2016), we estimate GHG emissions for the primary sectors, which represent emissions from fugitive leaks, vents and flaring ("non-fuel-combustion") activities. In this work, we also develop gridded emissions from the post-meter consumption of natural gas through combustion as well as fugitive leaks, which has not been reported previously. We compile activity data including well location and the production volume and natural gas consumption across California and apply emission factors derived from the US EPA's GHGI to the activity data following previous work (Jeong et al., 2014). Although this study estimates GHG emissions for California, we use the US EPA's GHGI to derive emission factors. This is because the state's official inventory from the California Air Resources Board (CARB) does not include emission factors for all natural gas-related sectors for which we estimate emissions. For example, the CARB inventory does not provide enough information for fugitive emission calculation from oil and gas production (CARB, 2019b).

We develop spatial inventories for all four primary source sectors (production, processing, transmission and distribution) and post-meter consumption emissions for $CH_4$ and $CO_2$. The current EPA GHGI does not include $N_2O$ activity data (including spatial information) or emission factors from publicly available sources for these primary sectors. Thus, $N_2O$ spatial inventories were only defined for post-meter consumption (mostly due to natural gas combustion) are developed. The sectors and subsectors included in this work are summarized in Table 1. $CO_2$ and $CH_4$ emissions for the primary sectors are estimated using emission factors derived from the 2018 EPA GHGI, while estimation of post-meter consumption emissions uses a combination of reported data in the EPA GHGRP and natural gas usage due to lack of detailed emission factors. As part of the post-meter consumption calculation, we also estimate natural gas-related $CH_4$, $CO_2$, and $N_2O$ emissions from natural gas end use facilities that include power plants, refineries, cement, food processing, chemicals, pulp & paper, metals, manufacturing, minerals, and other miscellaneous sectors (see Table 1) using information from GHGRP.

To be consistent with the US EPA's GHGI, we estimate only non-combustion (fugitive, flared and vented) emissions for the primary sectors except for the processing and transmission sectors where unburned engine exhaust $CH_4$ emissions are included (see Table 1). For the post-meter consumption sector, our ability to estimate combustion and non-combustion emissions separately is limited by the availability of data and depends on the gas. For example, while we estimate both fugitive and combusted $CH_4$ post-meter emissions for the residential, commercial and industrial subsectors, for $CO_2$ we do not estimate residential and commercial fugitive post-meter emissions due to lack of data (see Section 3.4). Note that the current EPA GHGI does not estimate post-meter emissions from the consumption of natural gas.

We estimate emissions as the product of emission factors and activity data (Jeong et al., 2014; Maasakkers et al., 2016):

$$E_x = E_f \times D_a$$

where $E_x$ is the emission of species X (e.g., $CH_4$), $E_f$ is the emission factor, and $D_a$ is the associated measure of activity (e.g., volume of gas produced).

We aggregate facility-level emissions to 0.1° × 0.1° (~10 km) gridded emissions as in Jeong et al. (2014) and Maasakkers et al. (2016). Many measurement-based top-down studies (e.g., Jeong et al., 2016; 2017; Cui et al., 2017) used gridded emission at 0.1° resolution as a priori information. Gridded emissions are estimated for 2016 by gas and by sector/subsector using the emission factors from the 2018 EPA GHGI (most recent edition published while conducting this work).

**Table 1**. Emission source sectors included in this work.

| Gas | Primary Sectors¶ | | Post-meter Consumption† | |
|---|---|---|---|---|
| | Sectors | Emission Types | Sectors | Emission Types |
| $CH_4$ | Oil and natural gas production | Fugitive, flared and vented | Post-meter residential | Fugitive and combusted |
| | Natural gas processing, natural gas transmission | Fugitive, flared and vented# | Post-meter commercial | Fugitive and combusted |
| | Natural gas distribution | Fugitive and vented | Post-meter industrial‡ | Fugitive and combusted |
| $CO_2$ | Oil and natural gas production | Fugitive, flared and vented | Post-meter residential | Combusted |
| | Natural gas processing, natural gas transmission | Fugitive, flared and vented | Post-meter commercial | Combusted |
| | Natural gas distribution | Fugitive and vented | Post-meter industrial‡ | Fugitive and combusted |
| $N_2O$ | NA* | NA | Post-meter residential | Combusted |
| | | | Post-meter commercial | Combusted |
| | | | Post-meter industrial‡ | Fugitive and combusted |

¶The primary sectors correspond to the sectors for the petroleum and natural gas systems in the EPA GHGI.
*Currently, US EPA does not estimate $N_2O$ emissions for the primary sectors, and we do not estimate $N_2O$ emissions for these sectors due to lack of data.
#Includes unburned $CH_4$ emissions in engine exhaust.
†Represents emissions from fugitive and/or combusted natural gas activities. For $CO_2$ and $N_2O$, residential and commercial emissions are estimated only for combustion due to lack of data. Since the focus is on natural gas, emissions for other fuel products (e.g., distillate oil) are not estimated in this work.
‡The industrial sub-sectors of the post-meter sector include fugitive and combusted emissions from power plants, refineries, food processing, chemicals, pulp & paper, metals, manufacturing, and minerals in the EPA GHGRP. A few minor sub-sectors (e.g., “Other” sub-sector) under GHGRP’s “Other” sector are not included in this work.

## 2.2 Data and Emission Factors

### 2.2.1 Oil and Gas Production

We use production well activities from the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR, 2016). The DOGGR database provides individual well locations, well-level production, well type, and other related information. Figure 1(A) shows the locations of individual natural gas wells (active and new) that produced oil and natural gas in 2016. Figure 1(A) does not include abandoned or plugged wells, which are assumed to be small in this work (Jeong et al., 2014; Maasakkers et al., 2016). We derive emission factors from the 2018 EPA GHGI for 2016. In this work, we aggregate the US EPA GHGI emission factors at the level where activity data are available (Jeong et al., 2014). Thus, as in Jeong et al. (2014), most of the emission factors are averages of component-level emission factors. For example, the EPA GHGI estimates many subsector emissions under the normal operations category, which requires information on the number of compressors, pumps, vessels and other components. Because we don't have publicly available component-level information with spatial attributes, we derive an aggregated emission factor from these subsectors and use it to estimate "Fugitive others" emissions (see Table 2). The derived production emissions factors (EF) for $CH_4$ and $CO_2$ are presented in Table 2.

We categorize wells in California into conventional and unconventional wells based on the well stimulation information available from California Department of Conservation (CDC, 2019). Here, we treat the stimulated wells as hydraulically fractured ones because hydraulic fracturing with proppant injection is used in ~90% of all stimulated wells in California with ~10% of sites using matrix acidizing and negligible acid fracturing (California Council on Science and Technology, 2015). Thus, we apply EPA's EFs for hydraulically fractured wells to the unconventional wells. Hereafter, we use unconventional wells and hydraulically fractured wells interchangeably.

We also distinguish between associated wells, which produce both oil and gas, and non-associated wells (i.e., dry gas wells) following the well type information from the DOGGR database. For associated wells, we use EFs for the petroleum (PL) system from the EPA GHGI while we apply EFs for the natural gas (NG) system to the non-associated wells (EPA, 2018a). For example, the liquid unloading EF in the NG system in Table 2 applies to the non-associated (dry) gas wells only.

In this work, emissions from the petroleum system (for associated wells) are calculated using an emission factor per unit oil production volume, which is different from Jeong et al. (2014) where they used natural gas production for both the PL and NG systems. We adopt this change because we found that many wells in California predominantly produce oil with a small volume of associated natural gas. Thus, in this work, emissions from associated wells are estimated as part of the PL system.

We estimate the state's total non-associated (dry) gas production for 2016 to be 22.3 billion cubic feet (Bcf) by summing the production volumes from all individual wells available in the DOGGR database. This total agrees well with the reported total of 22.6 Bcf in the 2016 DOGGR annual report (DOGGR, 2016). For oil production, which is used to estimate emissions from the petroleum system, we calculate the total oil production from the DOGGR database to be 186.1 million barrels (MMbbl), which is essentially the same as that (186.7 MMbbl) reported in the 2016 DOGGR report. Because the total emission from the PL system is significantly larger than that of the NG system (see the results section), it is important to verify the oil production from the DOGGR database against the summary in the DOGGR annual report. We verified the oil production by the DOGGR basin and the top producing field, comparing with the DOGGR annual report (see Appendix A).

**Table 2**. Emission factors for the production sector based on the 2018 EPA GHGI

| System | Production Subsectors | | $CO_2$ EF | $CO_2$ Units | $CH_4$ EF | $CH_4$ Units |
|---|---|---|---|---|---|---|
| NG¶ | Well testing | Vented | 0.09 | kg $CO_2$/well | 1.40 | kg $CH_4$/well |
| | | Flared | 0.63 | kg $CO_2$/well | 0.00 | kg $CH_4$/well |
| | Well completion | HF* vented | 104.64 | kg $CO_2$/event | 7473.78 | kg $CH_4$/event |
| | | HF flared | 108824.84 | kg $CO_2$/event | 4764.58 | kg $CH_4$/event |
| | | Non-HF vented | 3512.70 | kg $CO_2$/event | 34158.22 | kg $CH_4$/event |
| | | Non-HF flared | 30757.69 | kg $CO_2$/event | 167.69 | kg $CH_4$/event |
| | Well drilling | | 5.79 | kg $CO_2$/well | 52.15 | kg $CH_4$/well |
| | Liquid unloading | | 14.15 | kg $CO_2$/well | 318.73 | kg $CH_4$/well |
| | Workover | HF vented | 1.50 | kg $CO_2$/well | 61.74 | kg $CH_4$/well |
| | | HF flared | 177.32 | kg $CO_2$/well | 6.56 | kg $CH_4$/well |
| | | Non-HF vented | 0.00† | kg $CO_2$/well | 3.08 | kg $CH_4$/well |
| | | Non-HF flared | 0.03 | kg $CO_2$/well | 0.01 | kg $CH_4$/well |
| | Fugitive others | | 0.16 | kg $CO_2$/Mcf | 0.22 | kg $CH_4$/Mcf |
| PL‡ | Well testing | Vented | 1.01 | kg $CO_2$/well | 5.01 | kg $CH_4$/well |
| | | Flared | 60.57 | kg $CO_2$/well | 0.28 | kg $CH_4$/well |
| | Well completion | HF | 352.28 | kg $CO_2$/event | 6313.32 | kg $CH_4$/event |
| | | Non-HF | 0.79 | kg $CO_2$/event | 14.12 | kg $CH_4$/event |
| | Well drilling | | 0.00† | kg $CO_2$/well | 47.25 | kg $CH_4$/well |
| | Workover | | 0.01 | kg $CO_2$/well | 0.14 | kg $CH_4$/well |
| | Fugitive others | | 7.20 | kg $CO_2$/bbl | 0.47 | kg $CH_4$/bbl |

†less than 0.01 kg $CO_2$/well
*hydraulic fracturing (HF)
¶Represents emissions from non-associated wells.
‡Represents emissions from associated wells.

## 2.2.2 Natural Gas Processing Facility

We estimate emissions for the processing sector based on the volume of natural gas processed at each individual facility (Jeong et al., 2014). Natural gas processing facility (not including petroleum refining) information is reported in the Natural Gas Annual Respondent Query System (i.e., EIA-757) of Energy Information Administration (EIA). The EIA-757 dataset provides plant name, plant capacity and daily plant flow (EIA, 2019c). However, it provides only zip code for spatial information while GHGRP provides spatial information in longitude and latitude for reported plants, but without information on plant flow rates. Thus, we combine the two datasets to have both spatial information for mapping and flow rate for flow-weighted emission allocations.

Figure 1(B) shows the locations of natural gas processing facilities in California and the daily plant flow at each facility. Because component-level emission factors are not available for each facility, we estimate facility-level emissions by disaggregating the national total emissions from the EPA GHGI based on plant flow (i.e., weighted by plant flow on an annual basis), which is available from EIA-757 dataset (Maasakkers et al., 2016). The 2018 EPA GHGI reports 0.45 Tg $CH_4$/yr and 22.0 Tg $CO_2$/yr.

### 2.2.3 Pipelines, storage, compression and metering stations

The transmission sector includes emissions from storage facilities, compressor stations, metering stations, and other transmission emissions including pipeline leaks. We use georeferenced transmission sector data available from the California Energy Commission (CEC). Figure 1(C) shows the transmission pipelines in California, which include interstate and intrastate gas pipelines. The pipelines shown in Figure 1(C) represent natural gas pipelines that deliver natural gas from post-gathering systems to local distribution systems (CEC, 2018a). The total length of the pipelines shown in the figure is 12.90 × $10^3$ miles, which is longer than EIA's estimate of 11.77 × $10^3$ miles (EIA, 2008). This difference is likely due to the fact that the EIA estimate is based on the 2008 dataset, while the CEC dataset was updated in 2018.

To identify storage facilities, we use the spatial location information for underground storage wells from the DOGGR production database (see Appendix C for locations). The 2016 annual DOGGR report states that the gas withdrawn from underground wells is 154 Bcf. We calculate a total of 150 Bcf withdrawal from the storage wells we have identified in the DOGGR database, showing the total withdrawal from the spatial mapping of the storage wells based on the database matches that in the DOGGR report. Similarly, we use the CEC georeferenced dataset (CEC, 2018a; 2018b) to identify the spatial locations of transmission-related compressor and metering stations (distribution-level metering stations are not included; see Appendix C). Using a similar method to that of Jeong et al. (2014), we estimate emission factors for transmission stage subsectors, which are summarized in Table 3. Here, we note that EPA reports transmission emissions for the NG system, but does not report emissions from the PL system.

**Table 3**. Emission factors for the transmission sector.

| System | Subsectors | $CO_2$ EF | $CO_2$ Units | $CH_4$ EF | $CH_4$ Units |
|---|---|---|---|---|---|
| NG | Compressor station | 11.64 | Mg $CO_2$/station | 431.44 | Mg $CH_4$/station |
| NG | Storage station | 1.28 | Mg $CO_2$/well | 11.68 | Mg $CH_4$/well |
| NG | Metering station | 0.03 | Mg $CO_2$/station | 1.13 | Mg $CH_4$/station |
| NG | Transmission others* | 0.20 | Mg† $CO_2$/km | 0.51 | Mg $CH_4$/km |

*Includes pipeline leaks and other fugitive and vented emissions (e.g., venting from pneumatic controllers, unburned methane in transmission engine exhaust, pipeline venting) not attributed to compressor, storage and metering stations. These transmission others emissions are distributed in proportion to the pipeline length. Note that for compressor, storage, and metering stations, the emission factor is estimated for fugitive or vented emissions (including unburned methane in exhaust) at the station or well level.
†Mg = $10^6$ g

### 2.2.4 Natural Gas Distribution and Consumption

We estimate emissions from the distribution and post-meter consumption of natural gas. Recall that the distribution sector is considered a primary sector (Table 1). The current EPA GHGI does not account for post-meter emissions from the consumption of natural gas because EPA's emission estimates for the distribution sector are mainly for fugitive emissions from distribution pipelines and metering stations. In this work, we estimate emissions from post-meter fuel combustion separately from distribution emissions. Results from a recent study of residences are used for fugitive emissions (e.g., $CH_4$ leaks from home appliances) .

To estimate both distribution and consumption emissions of natural gas, we develop a map of natural gas consumption at 1 km by combining NG consumption data at the zip code level that is provided by three major utility companies in California and further disaggregating that information using a very high-resolution (~100 m) population density map. Statewide natural gas consumption information is provided at the zip-code level by Pacific Gas & Electric, Southern California Gas and San Diego Gas & Electric (SDGE), respectively. For spatial apportionment within each zip code area, we use a 1-km population map (see Appendix D), which is generated from the 100-m resolution data (WorldPop, 2018). For the regions that are not covered by these major utilities, we use EIA consumption data, apportioning the difference in consumption between EIA and the utilities to areas not covered by the utilities based on the population map. This disaggregation method is particularly useful for rural regions of California associated with a much larger spatial area for each zip-code than those of urban regions.

Figure 1(D) shows the population-weighted natural gas consumption map at 1-km resolution for California's residential and commercial sector. This result is a significant improvement from previous studies (e.g., Jeong et al., 2014, Maasakkers et al., 2016) where the population density (not consumption data itself) with only a moderate resolution (~10 km) was used as a proxy for the natural gas consumption.

The primary sources of the distribution sector emissions are normal fugitive emissions (from pipes and metering stations and customer meters) and vented emissions (from routine maintenance and upsets). Due to lack of detailed information, we use an aggregated emission factor similar to those used in Jeong et al. (2014) and Maasakkers et al. (2016). We divide the national $CH_4$ (480 Gg $CH_4$) and $CO_2$ (14.1 Gg $CO_2$) emissions from the 2018 EPA GHGI by the total natural gas consumption reported to EIA (15.18 $\times 10^{12}$ cf). Note that the EPA GHGI reports distribution emissions only from the natural gas system, not from the petroleum system. The EPA GHGI, instead, reports transportation (e.g., truck and rail loading of oil) emissions for the PL system. However, EPA GHGI's national transportation emissions are only 0.6% and 0% of the production emission totals for $CH_4$ and $CO_2$, respectively, and we do not include oil transportation emissions in this study. The calculated emission factors used in this work are shown in Table 4.

**Table 4**. Emission factors for the distribution sector.

| System | Sector | $CO_2$ EF | Units for $CO_2$ | $CH_4$ EF | Units for $CH_4$ |
|---|---|---|---|---|---|
| NG | Distribution | $9.31\times10^{-7}$ | Mg $CO_2$ / Mcf† NG | $3.16\times10^{-5}$ | Mg $CH_4$ / Mcf NG |

†Mcf = $10^3$ cf.

We estimate $CH_4$, $CO_2$, and $N_2O$ emissions from the post-meter consumption of natural gas. This post-meter consumption sector includes both fugitive and combustion emissions from the use of natural gas. Note that because this study focuses on natural gas infrastructure, we include combustion emissions from natural gas use, not including other petroleum products (e.g., distillate fuel oil). We estimate $CH_4$ emissions for the residential and commercial subsectors (both fugitive and combusted) using a recent residential measurement study (Fischer et al., 2018). For residential and commercial $CO_2$ and $N_2O$, because we do not have enough data for activities or emission factors, we estimate combustion emissions only. We note that current state and EPA inventories do not include post-meter fugitive emissions although CARB's inventory recently included residential post-meter fugitive emissions for a state total (CARB, 2019a). For fuel combustion, we estimate emissions for $CH_4$, $CO_2$, and $N_2O$ using natural gas usage and EPA GHGRP data.

To calculate residential post-meter $CH_4$ emissions, we adopt the state total for fugitive leaks and combustion estimated using measurements from 75 houses in California (Fischer et al., 2018) and apportion the total in proportion to natural gas consumption. Here, we assume that the emission rate of the commercial sector is the same as the residential sector estimated by Fischer et al. (2018), because there is no data or study result specific to post-meter commercial $CH_4$ emissions. Thus, to estimate commercial post-meter $CH_4$ emissions, we scale the residential poster-meter emissions using the commercial-to-residential consumption ratio. We use the gridded natural gas consumption data developed in this study combined with EPA's emission factors for stationary combustion (EPA, 2018) to estimate residential and commercial $CO_2$ and $N_2O$ emissions from natural gas combustion. Recall that we do not estimate fugitive $CO_2$ and $N_2O$ emissions for the residential and commercial subsectors. We use reported emissions from EPA's GHGRP as our estimates for the industrial consumption subsector whether they are fugitive or combusted emissions.

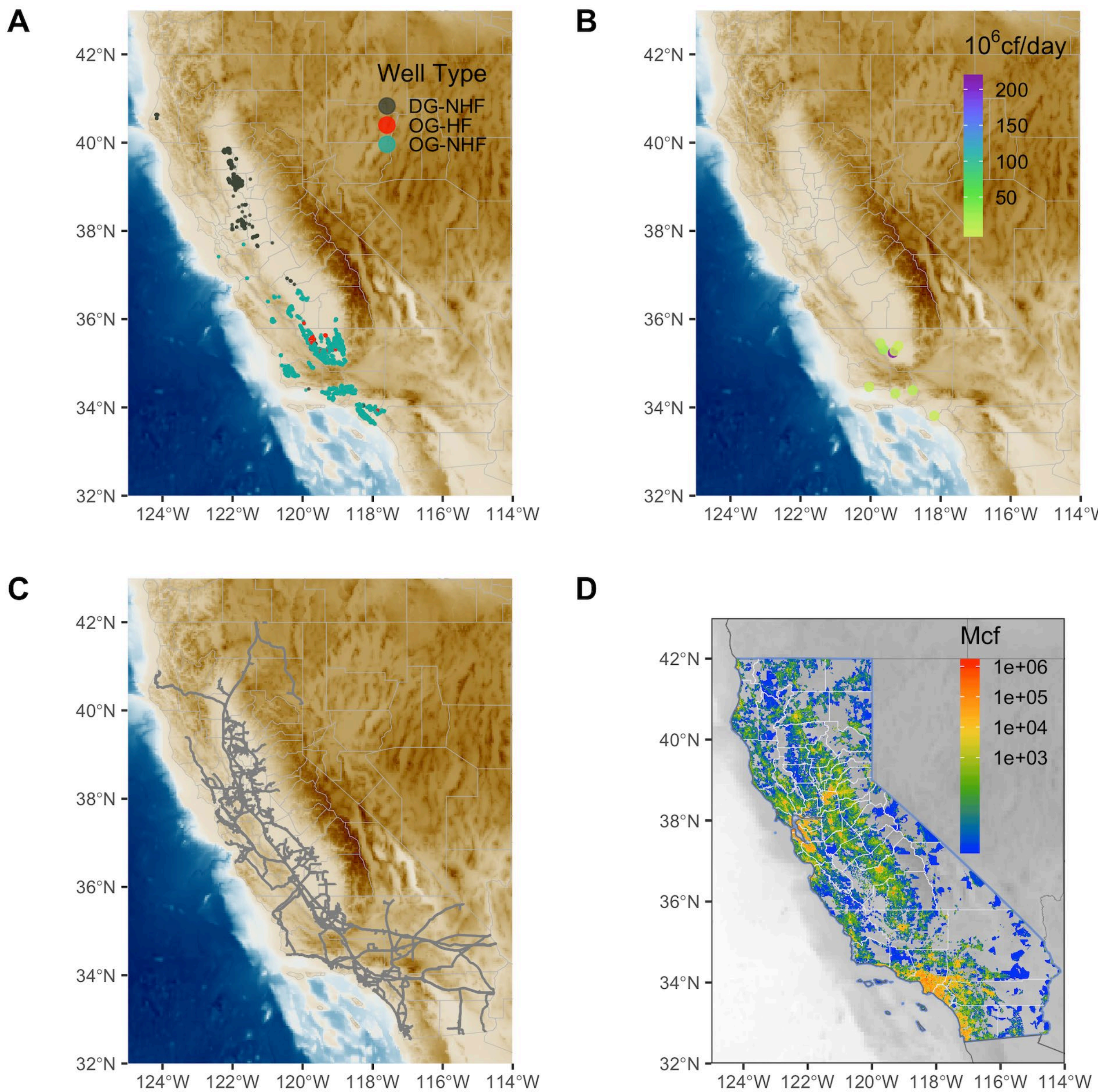


**Figure 1**. Activity data used in this study for emission estimation: (A) well locations from the 2016 DOGGR database by well type, (B) locations of natural gas processing plants from EIA, (C) transmission pipelines (CEC, 2018a), and (D) 2016 population-weighted annual natural gas consumption for the residential and commercial sectors. DG-NHF, OG-HF and OG-NHF in (A) represent dry gas (i.e., non-associated) without hydraulic fracturing, oil & gas (i.e., associated) with hydraulic fracturing, and oil & gas without hydraulic fracturing, respectively.

# 3. Results

## 3.1 Production

We estimate fugitive, flared and vented emissions from associated (oil & gas) and non-associated (dry gas) wells. The total emissions from the production sector account for 40.0% and 1.3% of the total emissions for $CH_4$ (229.8 Gg/yr) and $CO_2$ (97.2 Tg/yr) including the post-meter emissions, respectively. For $CH_4$, the total production emission (91.9 Gg/yr) is estimated to be 2.4% (ratio of $CH_4$ emissions per unit of natural gas) of California's total natural gas production (205 Bcf; EIA, 2020a) for 2016.

As described in the methods section, we apply emission factors for the NG and PL systems derived from the 2018 (for year 2016) EPA GHGI to non-associated and associated wells, respectively. Figure 2 shows the gridded $CH_4$ and $CO_2$ emission flux maps for the production sector where the estimated emissions from the NG (non-associated wells) and PL (associated wells) systems are combined at each grid cell (0.1° × 0.1°). As shown in the figure, both $CH_4$ and $CO_2$ emissions are concentrated in the southern San Joaquin Valley near Bakersfield. In Appendix A, we also show gridded emissions by the system, separating NG from PL emissions as well as estimated emissions for individual wells (before gridding).

We estimate 5.3 and 84.3 Gg $CH_4$/yr for the onshore NG and PL systems, respectively. The total of 89.7 Gg $CH_4$/yr estimated for 2016 is substantially smaller than that (130.5 Gg excluding offshore emissions) estimated by Jeong et al. (2014) for 2010. This is due to a combination of decreased dry gas production across California and reduced emission factors in the recent EPA GHGIs including the 2018 edition used in this work. We describe this more in the discussion section. When compared to the most recent state inventory, we find that our production total for $CH_4$ is larger than that of CARB (62 Gg $CH_4$/yr for 2017). However, our production total is smaller than an estimate (120 Gg $CH_4$) based on airborne measurements during 2016 – 2018 (Duren et al., 2019), suggesting actual production emissions are likely higher than the total estimated from this work.

For $CO_2$, we estimate 3.5 and 1296.9 Gg $CO_2$/yr for the onshore NG and PL systems (total = 1300.4 Gg), respectively. The $CO_2$ estimate from the NG system includes emissions from non-combustion sources, such as leaks, flaring and venting (EPA, 2018a). For the PL system at the national scale, the majority of the emissions occur from associated gas flaring, oil tanks with flares and other flaring activities (EPA, 2018a). Note that in Table 2, the fugitive others subsector represents these three major sources in aggregate because we don't have detailed information on these sources at the component level. As described in the method section, we assume these fugitive emissions for the PL system are proportional to the production volume of oil. Using the emission factors in Table 2, we find that 99% of the total (i.e., 1296.9 Gg $CO_2$) for the onshore PL system in California are from these three sources.

Using a similar method to Jeong et al. (2014), we estimate offshore emissions to be 2.18 Gg $CH_4$/yr and 0.67 Gg $CO_2$/yr for $CH_4$ and $CO_2$, respectively. Although there is no published estimate for offshore $CO_2$ emissions in California available for comparison with our estimate, we compare our offshore $CH_4$ emissions with the estimate from Jeong et al. (2014). Our offshore $CH_4$ total for 2016 is an order of magnitude smaller than that (37.2 Gg) of Jeong et al. (2014), which is an estimate for 2010. This decrease in offshore $CH_4$ emissions is partially because of a significant reduction in production for both oil and gas. We note that the 2016 oil and gas productions from the federal offshore facilities are only 28% and 11% of those in 2010 (Bureau of Safety and Environmental Enforcement, 2019).

Using a 100-yr global warming potential (GWP) of 25 g $CO_2$ /g $CH_4$ (Myhre et al., 2013), we estimate 2.30 Tg $CO_2$eq for the state total fugitive, flared and vented $CH_4$ for the production sector. In comparison to $CO_2$ emissions, our results suggest that $CH_4$ emissions are 1.8 times larger than fugitive, flared and vented $CO_2$ emissions in California. However, we note that a significant amount of fuel is combusted to provide energy in producing oil and gas including steam enhancement for oil recovery (CARB, 2019b). We describe emissions from combusted fuel for oil and gas production later in the consumption sector (also see Table 6).

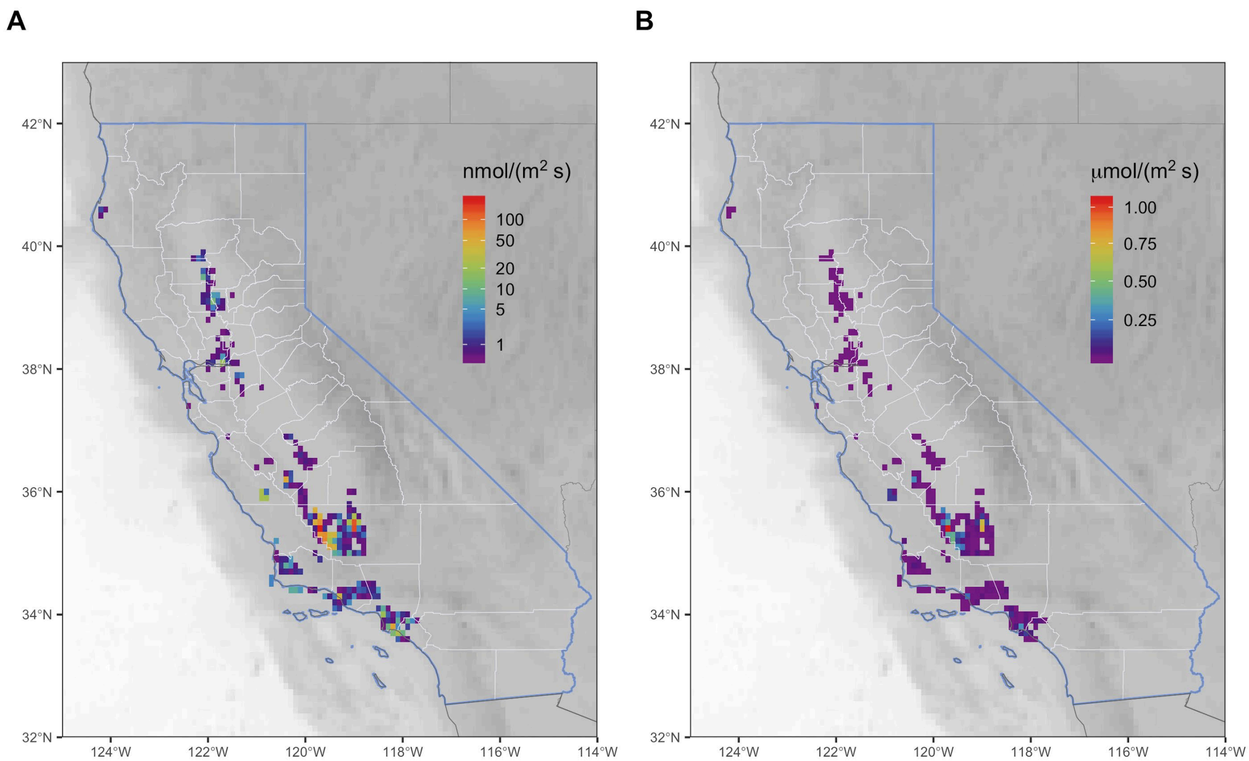


**Figure 2**. (A) $CH_4$ and (B) non-combustion $CO_2$ emissions from the oil and gas production (including offshore production). The estimated emissions for $CH_4$ and $CO_2$ are in units of nmol (i.e., $10^{-9}$ mol) / ($m^2$s) and μmol (i.e., $10^{-6}$ mol) / ($m^2$s), respectively.

## 3.2 Processing

The total processing emissions account for 1.0% and 0.1% of the total emissions for $CH_4$ (229.8 Gg/yr) and $CO_2$ (97.2 Tg/yr) estimated in this study, respectively. If we assume all of the natural gas production is processed in California's facilities, the total processing $CH_4$ emission (2.3 Gg

$CH_4$/yr) represents 0.06% (ratio of $CH_4$ emissions per unit of natural gas) of California's total natural gas production (205 Bcf; EIA, 2020a).

Figure 3 shows $CH_4$ and $CO_2$ emissions from natural gas processing facilities (see Appendix B for individual facility locations). We estimate 2.3 Gg $CH_4$/yr and 114 Gg $CO_2$/yr for $CH_4$ and $CO_2$, respectively. At the national scale, EPA estimates 0.45 Tg $CH_4$/yr and 22.0 Tg $CO_2$/yr for $CH_4$ and $CO_2$, respectively. For $CH_4$, our new estimate for the processing sector is much smaller than earlier estimates of 12.1 and 7 Gg $CH_4$/yr from Jeong et al. (2014) and Maasakkers et al. (2016), both of which use EPA GHGI emission factors. We attribute this difference partially to the decrease in EPA's estimates for processing emissions over time. For example, the 2016 EPA GHGI used in Maasakkers et al. (2016) estimates more than two times that (i.e., 0.45 Tg $CH_4$/yr) of the 2018 GHGI used in this work. Although total emissions from processing are relatively small, $CH_4$ emissions from some of the large facilities are comparable to $CH_4$ emissions from small landfills in California suggesting accurate characterization of processing emissions in space and magnitude is important. Converting to $CO_2$eq, we find that processing $CH_4$ emissions are 50% of $CO_2$ emissions at the annual scale. For petroleum processing and refining, we use estimates from the EPA GHGRP for 2016, which are 3.1 Gg $CH_4$/yr and 23.9 Tg $CO_2$/yr including fuel combustion and other process emissions. In a recent airborne measurement study, Duren et al. (2019) estimate the state's total refinery $CH_4$ emissions to be 8 – 23 Gg $CH_4$/yr, which are 2.6 – 7 times larger than that estimated in EPA's GHGRP. Mehrotra et al. (2017) also found a similar underestimation of refinery emissions from EPA's GHGRP. Note that for sector sums, the emissions for refineries are included in the industrial consumption sector (see Table 6).

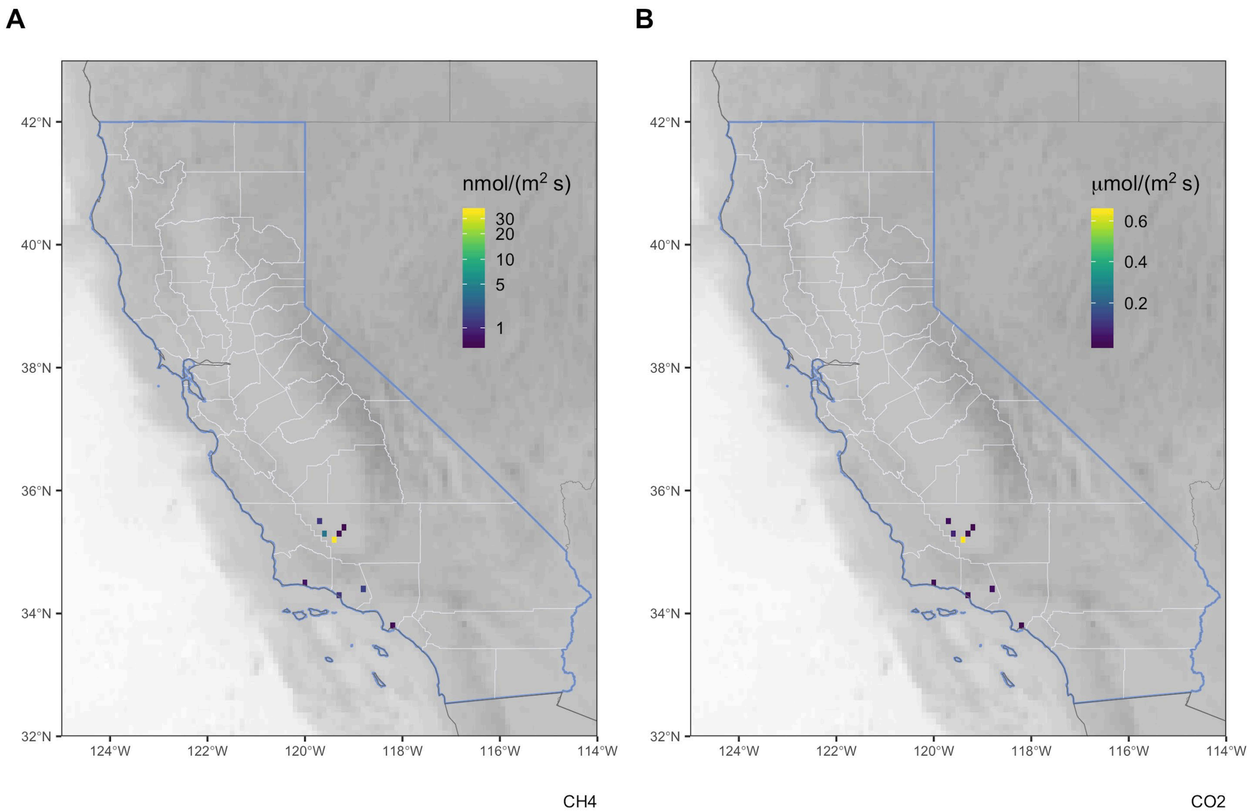


**Figure 3**. (A) $CH_4$ and (B) $CO_2$ emissions from natural gas processing facilities. The units are the same as in the production emission maps.

## 3.3 Transmission

The transmission emissions account for 14.5% and 0.01% of the total emissions for $CH_4$ (229.8 Gg/yr) and $CO_2$ (97.2 Tg/yr), respectively. The total transmission $CH_4$ emission (33.3 Gg $CH_4$/yr) estimated in this study indicates that 0.09% of the total natural gas delivered to customers (2108 Bcf; EIA, 2020b) is lost through the transmission infrastructure, assuming a $CH_4$ content of 93.4% per unit natural gas volume (US EPA, 2018a).

For the transmission sector, we estimate emissions from compressor stations, metering stations, storage facilities, and other transmission infrastructure including major pipelines (local distribution pipelines are included in the distribution sector; see Table 3 for subsectors). Figure 4 shows the gridded $CH_4$ and $CO_2$ emissions for the combined transmission sector, and the gridded emission map for each subsector is presented in Appendix C. Emissions for the transmission others subsector are estimated as a function of pipeline length, as described in the methods section. As size-dependent emission factors are unavailable we apply a uniform emission factor to all pipelines, as in Jeong et al. (2014).

Summing over the gridded emissions across California, we estimate state total $CH_4$ emissions (fugitive, flared and vented) from the transmission others subsector (mostly pipelines) to be 10.54 Gg $CH_4$/yr and 4.18 Gg $CO_2$/yr for $CH_4$ and $CO_2$, respectively (Table 5). Note that these estimates represent all emissions excluding station (i.e., compressor, storage, and metering stations) emissions. For compressor stations, we estimate 17.69 Gg $CH_4$/yr and 0.48 Gg $CO_2$/yr. We estimate storage-related emissions to be 4.35 Gg $CH_4$ and 0.48 Gg $CO_2$, respectively. The metering and regulating (MR) station emissions are relatively small compared to the other sector emissions (see Table 5). The MR station $CH_4$ total is 0.72 Gg $CH_4$/yr, only 4% of that from compressor stations. Nationally, MR stations emit 9% of the compressor station emission total (EPA, 2018a). Among the four subsectors of the transmission sector, compressor stations account for the largest portion of the total $CH_4$ emission (53%) followed by the transmission others subsector (32%). For $CO_2$, the transmission others subsector accounts for 81% of the transmission total. Although a limited number of cells on the 0.1° × 0.1° grid contains compressor stations, an accurate spatial characterization of these stations is important for research using top-down inverse modeling approaches because some of them have high emission rates (see Figure 4). In comparison with previous $CH_4$ studies, our total (33.3 Gg $CH_4$) is somewhat higher than those (21 and 24 Gg $CH_4$/yr) of Jeong et al. (2014) and Maasakkers et al. (2016). However, our transmission total is similar to an estimate (1.68 Bcf or 31.2 Gg using $CH_4$ density of 18.58 g/ft$^3$) from CARB and CPUC (California Public Utilities Commission; CARB & CPUC, 2018) although they attribute most of the emissions to MR stations.

**Table 5.** Transmission emission sums by the sector†.

| Sector | $CH_4$ Gg/yr | $CO_2$ Gg/yr |
|---|---|---|
| Compressor station | 17.69 | 0.48 |
| Metering & regulating (MR) station | 0.72 | 0.02 |
| Storage station | 4.35 | 0.48 |
| Transmission others* | 10.54 | 4.18 |
| Total | 33.29 | 5.16 |

†Represents fugitive, flared and vented emission sums for the transmission sector. Note that the compressor and storage subsectors include unburned $CH_4$ emissions in exhaust.
*This estimate includes all other fugitive, flared and vented emissions other than compressor, metering and storage facilities.

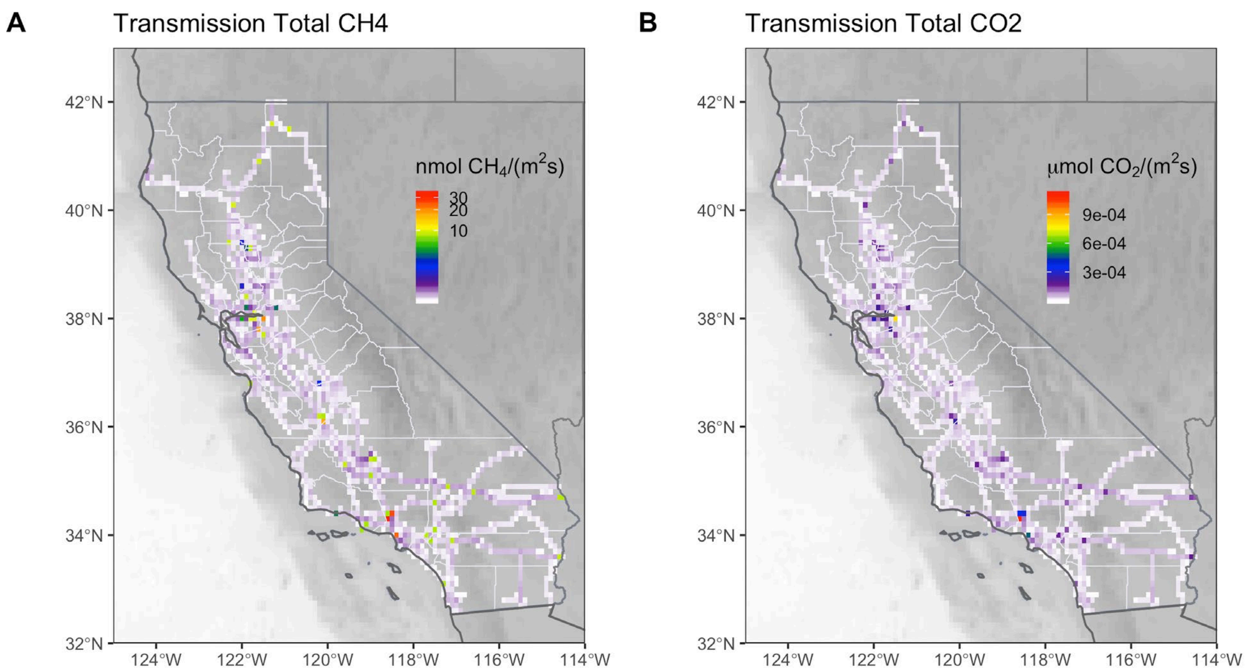


**Figure 4.** (A) $CH_4$ and (B) $CO_2$ emissions from the transmission sector.

## 3.4 Distribution and Consumption

The combined total emissions for the distribution and post-meter consumption sectors account for 44.5% and 98.5% of the total emissions for $CH_4$ (229.8 Gg/yr) and $CO_2$ (97.2 Tg/yr), respectively. The combined total $CH_4$ emission for distribution and consumption (102.4 Gg $CH_4$/yr) estimated in this study indicates that 0.27% of the total natural gas delivered to customers (2108 Bcf; EIA, 2020b) is lost, assuming a $CH_4$ content of 93.4% per unit natural gas volume (US EPA, 2018a).

We distinguish emissions from post-meter consumption (e.g., residential and commercial appliance leakage) of natural gas from leaked emissions from distribution pipelines and stations, which are included in the distribution sector of EPA's GHGI (EPA, 2018a). Note that the distribution sector in EPA's GHGI includes emissions occurring from city gate stations to service lines to end users' meters, but does not include post-meter emissions. City gate stations connect interstate pipelines with local distribution pipelines, and are designed to meter natural gas and reduce its pressure for safe delivery to local customers. Following the EPA GHGI sector classification, we regard the distribution emissions as representing normal fugitive and vented emissions only while including emissions from fuel combustion in the consumption sector.

Distribution emissions for the residential and commercial subsectors are allocated based on the high-resolution residential and commercial natural gas consumption map developed in this work (see Figure 1(D)). We also estimate distribution emissions from the industrial subsector, apportioning the total estimated subsector emissions based on the EPA GHGI in proportion to the reported emissions from individual industrial facilities in the EPA GHGRP.

Figure 5 shows the gridded $CH_4$ and $CO_2$ emissions for the combined residential, commercial, and industrial subsectors of the distribution sector. Summing emissions across all the grid cells in the figure, we estimate a total of 20.5 Gg $CH_4$/yr and 0.60 Gg $CO_2$/yr for the combined residential and commercial subsector. Similarly, we estimate 24.48 Gg $CH_4$/yr and 0.72 Gg $CO_2$/yr for the industrial subsector. These industrial totals are spatially allocated in proportion to the reported emissions from industrial facilities in the EPA GHGRP because we do not have zip-code level natural gas consumption for the industrial sector as opposed to the residential and commercial subsectors.

Combining all three subsectors of the distribution sector, which represents normal fugitive and vented emissions, we estimate 45.0 Gg $CH_4$/yr and 1.3 Gg $CO_2$/yr. We note that the total $CO_2$ emission from the distribution sources is less than 1% of the $CH_4$ total when converting $CH_4$ emissions to $CO_2$eq using a GWP of 25 g $CO_2$eq / g $CH_4$. California's total consumption for the residential, commercial and industrial subsectors is 9% of the US total consumption for these three sectors. Our estimated emissions for $CH_4$ and $CO_2$ are both ~9% of the US totals (480 Gg $CH_4$ and 14 Gg $CO_2$), a result that our state-level emissions are based on EFs from the EPA GHGI. However, our gridded inventory for the residential and commercial subsectors represents allocation of emissions based on a high-resolution natural gas consumption map instead of using population density as a proxy for consumption, as approached in previous studies. Our industrial gridded inventory uses the reported emissions in the EPA GHGRP as a proxy for disaggregation while matching our estimate totals (i.e., 24.48 Gg $CH_4$/yr and 0.72 Gg $CO_2$/yr).

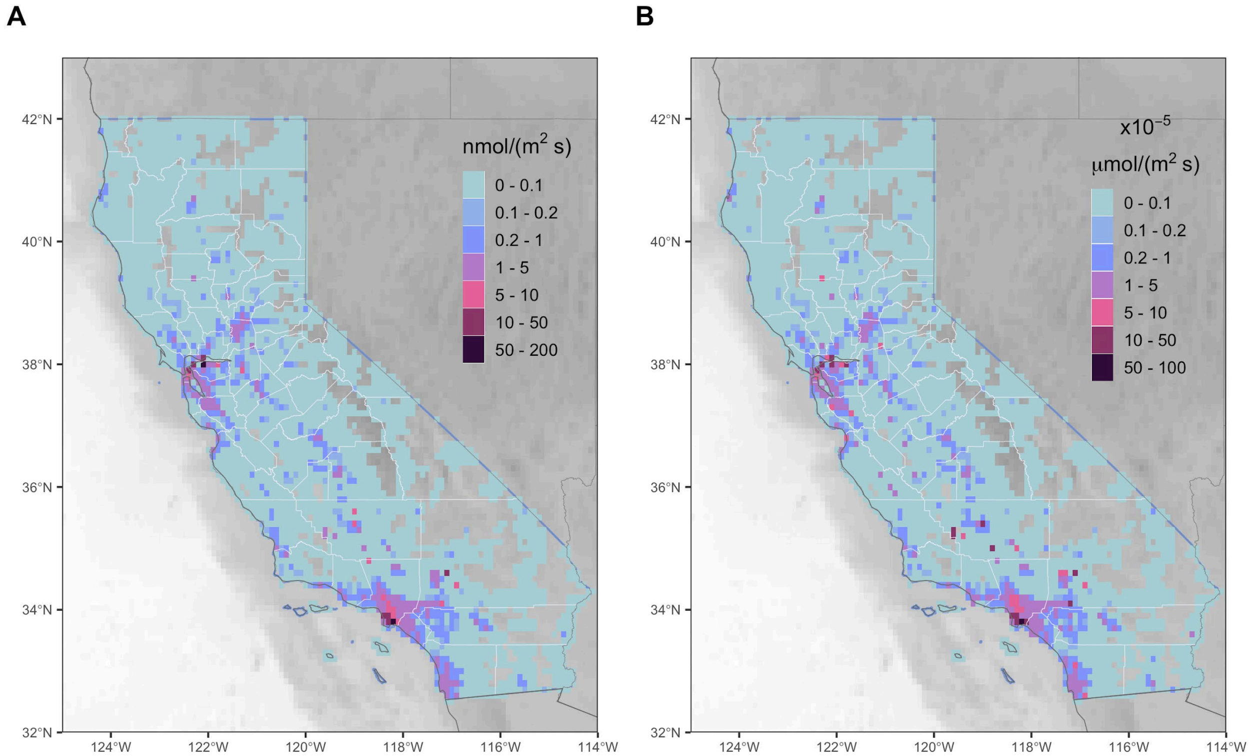


**Figure 5**. Estimated distribution emissions at 0.1° resolution (~10 km) for the residential, commercial, and industrial subsectors: (A) $CH_4$ and (B) $CO_2$.

We estimate emissions for the post-meter consumption sector using a combination of published literature, gridded natural gas consumption data developed in this work, and the EPA GHGRP data (see Table 6). We estimate post-meter $CH_4$ emissions from residential natural gas consumption based on a recent study that inferred residential $CH_4$ emissions using measurements from California's 75 houses and a Bayesian method (Fischer et al., 2018). Fischer et al. (2018) estimated California's residential post-meter fugitive and combustion (unburned $CH_4$) emissions to be 35.7 (21.7 − 64.0 at 95% confidence) Gg $CH_4$/yr for 2016, which was also adopted by CARB in the most recent official inventory (CARB, 2019a). In a national-scale study, Saint-Vincent and Pekney (2019) estimated a total of 144.36 Gg $CH_4$/yr for the US post-meter residential sector using measurement-based results from Fischer et al. (2018) for quiescent houses and Merrin and Francisco (2019) for major appliances. For comparison, using the 2017 housing total ratio (10.8%; American Housing Survey, 2017) for California vs. the US, we estimate a total of 15.6 (=144.36 × 0.108) Gg $CH_4$/yr for California, which is smaller than that of Fischer et al. (2018) adopted in this work. This is because the appliance emissions estimated by Merrin and Francisco (2019) are generally low compared to those of Fischer et al. (2018) although the results from the two measurement studies are consistent within uncertainty. We allocate this total $CH_4$ emission for the residential poster-meter consumption in proportion to the gridded residential consumption map.

To estimate post-meter $CH_4$ (fugitive and combustion) emissions from the commercial consumption of natural gas, we adjust the residential post-meter consumption emission by the ratio of commercial to residential natural gas consumption. As stated in the method section, this approach assumes the same emission factor for the commercial sector as that of the residential sector, while this ratio needs to be verified by future studies. Using the commercial-to-residential consumption ratio (0.58), we estimate a total of 20.5 Gg $CH_4$/yr from the commercial natural gas end-use, which is disaggregated spatially following the gridded commercial natural gas consumption map. As in the CARB inventory, we do not estimate fugitive residential and commercial consumption emissions for $N_2O$ and $CO_2$ because we do not have sufficient data.

For the industrial post-meter consumption sector, we adopt reported emissions from EPA's GHGRP, which include both fugitive and combusted emissions of natural gas. We note that because EPA's GHGRP includes facilities with emissions larger than 25 Gg $CO_2$eq/yr, actual emissions are likely higher than the reported emissions (Maasakkers et al., 2016). However, because we do not have sufficient activity data at the individual industrial facilities with which to create new estimates, we use the reported emissions for the industrial consumption data. Using EPA's GHGRP, we estimate 0.85 Gg $CH_4$/yr, 45.57 Tg $CO_2$/yr, and 0.09 Gg $N_2O$/yr for natural gas consumption, respectively (see Table 6).

We explicitly estimate emissions from fuel combustion at facilities that produce oil and gas. While fuel consumption for oil and gas production alone is not available, CARB provides the combined fuel consumption for oil and gas production and processing (CARB, 2019b). Applying EPA's stationary combustion emission factors (EPA, 2018b), we estimate 0.28 Gg $CH_4$/yr and 14.88 Tg $CO_2$/yr for the fuel combustion subsector of the oil and gas production and processing sector (also see Table 6). To distinguish emissions between production and processing, if we assume that the fuel combustion emissions are proportional to the estimated emissions from the non-fuel-combustion activities, the $CO_2$ emission from the production fuel combustion alone would be 13.68 Tg $CO_2$/yr. Note that the total non-fuel-combustion $CO_2$ emission for production is 11.4 times larger than the one for processing.

Table 6 shows the total emissions from the post-meter consumption of natural gas. $CO_2$ emissions account for 98% (97.28 Tg $CO_2$eq) of the total emission, when converting $CH_4$ and $N_2O$ emissions to the units of Tg $CO_2$eq. This result also shows that consumption is the major sector in the entire NG and PL systems in California (also see Figure 8).

**Table 6**. Summary of estimated post-meter consumption emissions by gas.

| Greenhouse Gas | Sector | Subsector | Emissions[‡] | Units |
|---|---|---|---|---|
| $CH_4$ | Residential[#] | Fugitive and natural gas combustion | 35.7 | Gg $CH_4$/yr |
| | | | | Gg $CH_4$/yr |
| | Commercial[#] | Fugitive and natural gas combustion | 20.54 | Gg $CH_4$/yr |
| | | | | Gg $CH_4$/yr |
| | Industrial[†] | Fugitive and natural gas combustion | 1.13 | Gg $CH_4$/yr |

| | | | | |
|---|---|---|---|---|
| | **Total** | | **57.37¶** | Gg $CH_4$/yr |
| $CO_2$ | Residential | Fugitive | NA* | Tg $CO_2$/yr |
| | | Natural gas combustion | 22.42 | Tg $CO_2$/yr |
| | Commercial | Fugitive | NA* | Tg $CO_2$/yr |
| | | Natural gas combustion | 12.90 | Tg $CO_2$/yr |
| | Industrial† | Fugitive and natural gas combustion | 60.45§ | Tg $CO_2$/yr |
| | **Total** | | **95.77** | Tg $CO_2$/yr |
| $N_2O$ | Residential | Fugitive | NA* | Gg $N_2O$/yr |
| | | Natural gas combustion | 0.04 | Gg $N_2O$/yr |
| | Commercial | Fugitive | NA* | Gg $N_2O$/yr |
| | | Natural gas combustion | 0.02 | Gg $N_2O$/yr |
| | Industrial† | Fugitive and natural gas combustion | 0.09 | Gg $N_2O$/yr |
| | **Total** | | **0.15** | Gg $N_2O$/yr |

*Due to lack of data, these fugitive emissions are not estimated.
†Shows the sums of fugitive and combusted emissions from power plants, refineries, food processing, chemicals, pulp & paper, metals, manufacturing, and minerals in the EPA GHGRP.
‡Represents natural gas-related emissions from either fugitive or combustive activities not including other fuel products (e.g., fuel oil, wood burning).
#Estimated for a combined total for fugitive and combustion emissions using results from Fischer et al. (2018).
¶Includes 0.28 Gg $CH_4$ of combustion emissions for oil and gas production and processing activities.
§Includes 14.88 Tg $CO_2$ of combustion emissions for oil and gas production and processing activities.

## 3.5 State Total Emissions

We first summarize state total emissions (i.e., fugitive, vented and flared) for the primary sectors by combining emissions from the four sectors included in the EPA GHGI (see Table 1): production, processing, transmission and distribution sectors. Figure 6 shows state total gridded emissions for the primary sectors. We estimate state total emissions for $CH_4$ and $CO_2$ to be 172 Gg $CH_4$/yr and 1421 Gg $CO_2$/yr, respectively. Converting $CH_4$ emissions to units of $CO_2$eq (GWP = 25), we find that $CH_4$ emissions are 4.3 Tg $CO_2$eq, which is three times larger than the corresponding $CO_2$ emissions, though it does not include $CO_2$ from fuel combustion associated with each subsector. In comparison to previous studies, our total $CH_4$ emission estimate for the primary sectors are significantly smaller than those estimated by Jeong et al. (2014, 331 Gg $CH_4$) and Maasakkers et al. (2016, 334 Gg $CH_4$). We further discuss this difference in the discussion section.

Following Jeong et al. (2014), we estimate the uncertainty for our primary sector emissions from the natural gas and petroleum systems. The uncertainty estimate is based on EPA's overall uncertainty estimation for the natural gas and petroleum systems which is calculated as the percentage deviation from the mean estimates. We assume a lognormal distribution for the emission total and fit the lognormal distribution using the percentage deviation from EPA (see

Jeong et al., 2014 for details). Incorporating EPA's deviation uncertainty (lower bound = 16%, upper bound = 17%), we estimate $CH_4$ emissions to be 143 – 203 Gg $CH_4$/yr. For $CO_2$ (lower bound = 30%, upper bound = 34%), we estimate $CO_2$ emissions to be 1059 – 1879 Gg $CO_2$/yr. We note that EPA estimates for the US as a whole may not accurately reflect uncertainties specific to California NG infrastructure and deserve future consideration based on location-specific top-down studies.

Figure 7 shows primary sector emission sums for California's major air basins by sector. The major emitting regions includes the San Joaquin Valley (SJV), the Sacramento Valley (SV), South Coast Air Basin (SoCAB), and the San Francisco Bay Area (SFBA). SJV and SV are major production regions for oil and non-associated gas, respectively while SoCAB and SFBA are the two major metropolitan areas in California. The production emissions are predominantly from SJV followed by SoCAB and SV (Figure 7). For $CH_4$, SJV emits 74% of the total production emissions, while SoCAB and SFBA account for 57% of the total distribution emission in California . For $CO_2$, the production emissions account for 91% of the total emissions for the primary source sectors, which are concentrated in SJV. Note that the majority of the non-fuel-combustion $CO_2$ emissions occur from flaring activities but are still small compared to $CO_2$ (14.88 Tg) released from fuel combustion for oil and gas production and processing (see Table 6).

Figure 8 shows a summary of all emissions estimated by the sector and GHG including the consumption sector, which includes mostly natural gas combustion sources (also see Table 7). The total emission for California's major natural gas infrastructure and consumption is 103 Tg $CO_2$eq/yr. Note that we do not include some minor sectors in the "Other" sector of EPA's GHGRP (see Table 1). Converting all emissions to $CO_2$eq using 100-year GWPs (see Table 7), we find that the post-meter consumption accounts for the majority of the total emission (94%) followed by non-fuel-combustion production & processing (4%). This is because the stationary combustion $CO_2$ emissions from different industrial sources are overwhelmingly larger than our $CO_2$ estimate for the non-fuel-combustion primary sources, with power plants being the major source (see Appendix E). When we combine the non-fuel-combustion primary sectors and the consumption sector, we estimate that $CO_2$ is the major GHG in the natural gas-related emissions accounting for 94% of the total, followed by $CH_4$ (6%).

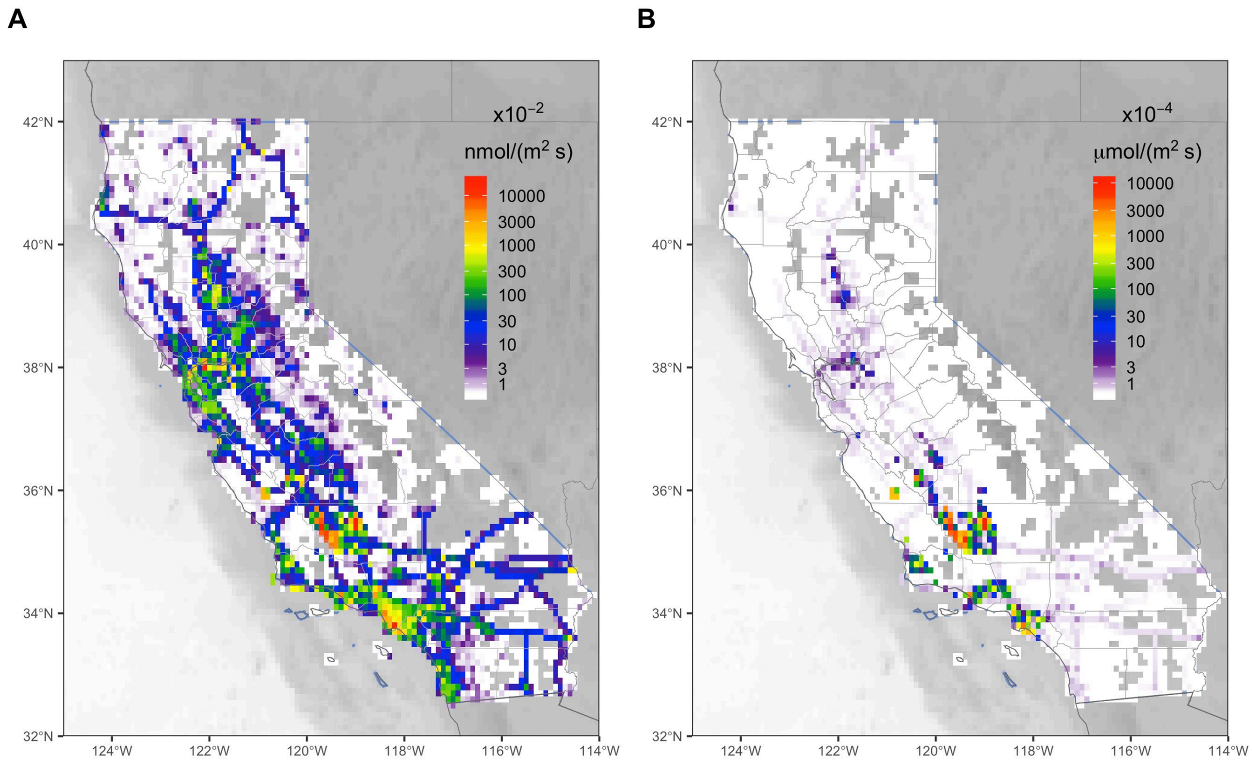


**Figure 6**. State total emissions (fugitive, vented, flared) for (A) $CH_4$ and (B) $CO_2$ from the primary sectors. Note the consumption sector emissions are not included in the maps.

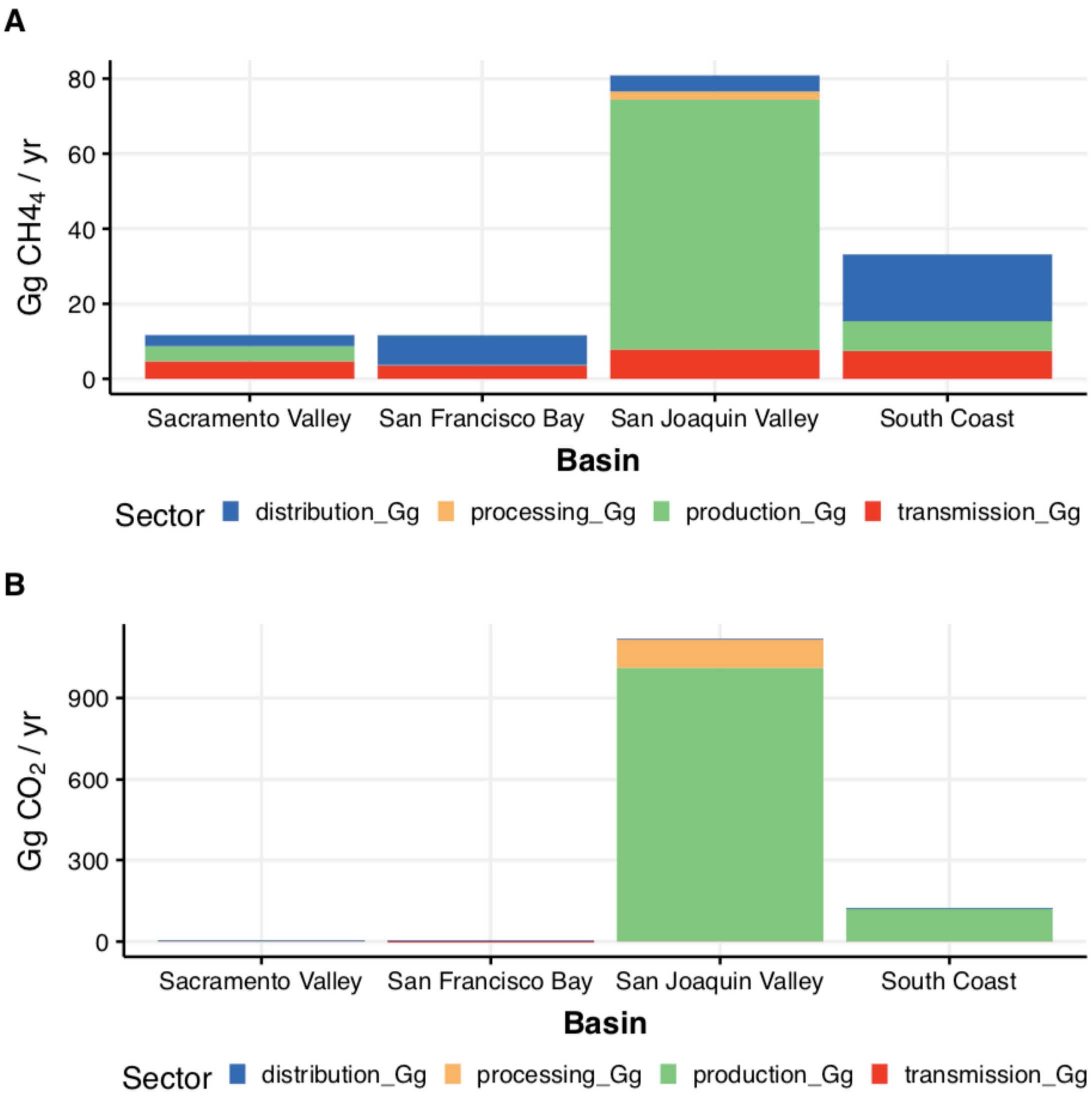


**Figure 7**. Emission sums for $CH_4$ (panel A) and $CO_2$ (for panel B) for major air basins in California by the sector. Only emissions from the primary source sectors are shown.

**Table 7**. Summary for emissions by sector including the consumption sector.

| Sector | $CH_4$ (Gg) | $CO_2$ (Gg) | $N_2O$ (Gg)* | $CH_4$ (Tg $CO_2$eq)† | $CO_2$ (Tg $CO_2$eq) | $N_2O$* (Tg $CO_2$eq)† |
|---|---|---|---|---|---|---|
| Production & Processing | 94.19 | 1415.12 | NA | 2.35 | 1.42 | NA |
| Transmission | 33.29 | 5.16 | NA | 0.83 | 0.01 | NA |
| Distribution | 44.99 | 1.32 | NA | 1.12 | 0.00 | NA |
| Consumption¶ | 57.37 | 95771.45 | 0.15 | 1.43 | 95.77 | 0.05 |

*For $N_2O$, only the consumption sector is estimated due to lack of data for other sectors (EPA, 2018a).
†GWP: 25 g $CO_2$eq / g $CH_4$ and 298 g $CO_2$eq / g $N_2O$.
¶Includes combustion emissions for oil and gas production and processing activities (see Table 6).

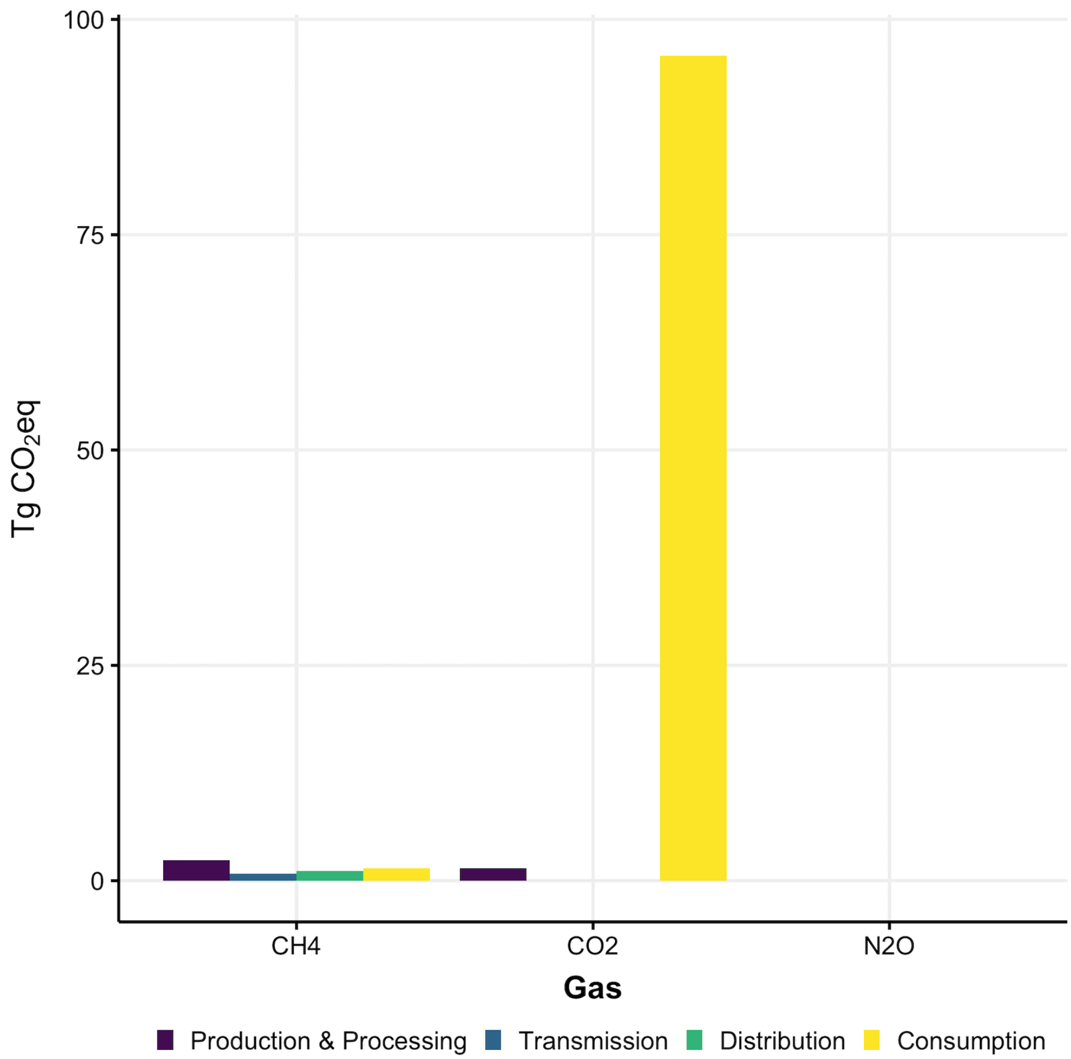


**Figure 8**. Summary for emissions by the sector and GHG including both the primary and consumption sectors.

# 4. Discussion

We estimate $CH_4$ and $CO_2$ emissions using a consistent framework that enables us to compare $CH_4$ and $CO_2$ emissions specific to PL and NG systems in California. We find that using a 100-yr GWP, $CH_4$ emissions specific to the PL and NG systems in California (4.3 Tg $CO_2$/yr ) are three times larger than those of $CO_2$ for fugitive, flared and vented processes but small compared to the total $CO_2$ emission (97.2 Tg $CO_2$/yr) that includes all industrial emissions from natural gas consumption. This suggests that on a shorter timescale, mitigating $CH_4$ emissions can be more effective in mitigating climate impact than $CO_2$ for fugitive, flared and vented activities, although the total natural gas-related $CO_2$ emission in California is overwhelmingly larger than that of $CH_4$. This result further suggests that reduction of combustion emissions remains an important goal for climate impact mitigation in California's natural gas-related sectors.

We compare the $CH_4$ emission estimates from this work with those from previous studies. Our total estimate for the primary sectors is smaller than those of Jeong et al. (2014) and Maasakkers et al. (2016). Figure 9(A) shows the comparison for estimated $CH_4$ emissions among different studies. In particular, the total $CH_4$ emission for the production sector from this work is significantly smaller than those of Jeong et al. (2014) and Maasakkers et al. (2016). As shown in Figure 9(B), this is because the U.S. NG system production emission from the 2018 EPA GHGI (for 2016) is only 4302 Gg $CH_4$ /yr, compared to 6002 Gg $CH_4$ /yr from the 2012 GHGI (for 2010). It is worth noting that the recalculated 2010 U.S. NG system production emission from the 2018 GHGI is 4312 Gg $CH_4$. This difference between the 2012 and 2018 GHGIs is because the U.S. EPA continues to revise the inventory for oil and gas production as well as the entire NG and PL systems, incorporating information from new scientific studies, activity data and stakeholder feedback. The production (including exploration) sector is composed of several subsectors including well completion, workover, gathering/boosting and normal operations, and emission factors associated with each of the subsectors are updated with the release of a new GHGI each year (see EPA, 2018a and EPA 2018c for detailed updates in 2018). For example, the US EPA conducted a major update in the liquids unloading (a well clean-up process) methodology in 2017 using year-specific emission factors (EPA, 2018c) instead of applying fixed ones as in the previous reporting years. Based on the updated method, the 2016 emission factor (1.6 Mg $CH_4$/well, from 2018 GHGI) for the plunger lift liquids unloading decreased by a factor of three compared to that of 2011. Similarly, for HF gas well completions and workovers, EPA adopted year-specific emission factors and recalculated emissions in the 2018 GHGI. For instance, the HF non-reduced emissions completion (non-REC) venting emission factor in 2016 is only 17% of that for 2011 while the HF REC venting emission factor in 2016 is approximately two times larger than that of 2011. Furthermore, activity factors such as the fraction of control (vent vs. flare) for each event (e.g., completion, workover) vary by year. The 2018 GHGI incorporated year-specific control fractions showing a large inter-annual variation (e.g., 69% flared completion in 2016 vs. 3% in 2011). Note that the fraction of control for each event affects the overall emission for each event because each event's total emission is the sum of the emissions for different control types. Although this study does cover all the recent changes in emission factors for the production sector, more details can be found in EPA documents (e.g., EPA, 2018a, EPA 2018c).

In addition, California's total dry gas production (22 Bcf) in 2016 is ~3 times smaller than that of the 2010 production reported in the 2010 DOGGR annual report. This decreased production in dry gas and low emission factors contribute to the reduction in the NG system $CH_4$ emissions for 2016. We note that the 2016 GHGI used in Maasakkers et al. (2016) reports 1.5 times higher (2302 vs. 1499 Gg $CH_4$) U.S. emissions for the PL system than that of the 2018 GHGI used in this study while the NG system emissions are similar (see Figure 9(B)).

We compare our estimates for San Francisco Bay Area and Southern California Air Basin total NG-related $CH_4$ emissions with results from recent top-down studies; there are no NG-related $CO_2$ studies to compare with. Jeong et al. (2017) estimated a total of 17 Gg $CH_4$/yr in their 1-km gridded inventory for SFBA, which is 1.5 times larger than our estimate (11.6 Gg) for SFBA. The Jeong et al. (2017) value from the SFBA gridded inventory does not include post-meter fugitive emissions. Using this spatial inventory and multi-species measurements including methane and ethane, the authors estimated annual total emissions of 23 – 38 Gg $CH_4$/yr, which are larger than our estimate by factors of 2 – 3. However, if we add the consumption emissions (10.5 Gg) estimated in this study to the distribution emission total, the top-down estimates by Jeong et al. (2017) will be 1.0 – 1.7 times larger than our combined total for the primary and post-meter consumption sectors for SFBA. In SoCAB, which includes the Los Angles (LA) metropolitan, Kuwayama et al. (2019) estimated that 56 – 79% of the LA $CH_4$ emissions are emitted from natural gas sources while Hopkins et al. (2016) reported that fossil sources contribute to 58 - 65% of $CH_4$ enhancement in the ambient air of LA. In an earlier study (for 2010), Peischl et al. (2013) reported that 55% (including geologic seeps) of the total SoCAB $CH_4$ emission was from natural gas-related sources. These studies indicate that the natural gas source contribution to the total in SoCAB has not decreased over time. Using $CH_4$ measurements from multiple towers, Jeong et al. (2016) estimated 301 - 490 Gg $CH_4$ (at 95% confidence) for SoCAB. They also compared seven other top-down estimates for SoCAB $CH_4$ and showed the total $CH_4$ emissions in SoCAB are likely ~400 Gg $CH_4$/yr. Combining the natural gas source apportionment and top-down studies for the SoCAB total, it is likely that the total $CH_4$ emissions related to natural gas activities (including associated gas production) are significantly higher than our estimate for SoCAB (33 Gg $CH_4$/yr). For example, if we assume that the estimates of Jeong et al. (2016, for the total) and Kuwayama et al. (2019, for the % of natural gas consumption) are correct, then the natural gas-related $CH_4$ total is 240 – 316 Gg/yr (400 × 0.56 – 400 × 0.79). Note that our SoCAB total is only 40% of the bottom-up estimate from Jeong et al. (2014), which itself is lower than most of the recent top-down estimates in the region.

We partially attribute the discrepancy between this work's estimate (based on the updated EPA GHGI) and top-down estimates by other authors to EPA's low emission factors for the distribution sector. Our estimate for the statewide distribution $CH_4$ total is slightly higher than that estimated by Maasakkers et al. (2016), which is based on the 2016 EPA GHGI. Also, both Maasakkers et al. (2016) and this work use EPA GHGIs' estimates with lower national distribution emissions of 444 and 480 Gg $CH_4$ than the 1359 Gg $CH_4$ estimated from the 2012 GHGI (for 2010) used in Jeong et al. (2014). Based on the 2018 GHGI, which updates the distribution emissions for 1990 – 2016, the distribution $CH_4$ emission total (480 Gg) in 2016 is 28% and 87% of those in 1990 and 2010, respectively, even though the total length of the distribution pipelines has grown significantly

(EPA, 2018a). This clearly shows that the distribution emission estimation, as in the production sector, is affected by the GHGI used, because EPA's GHGI continues to be revised. EPA attributes the reduction in the distribution emissions to upgrades in utility infrastructure, leak surveys and use of modern materials (EPA, 2018a). For example, EPA suggests that an increase in the use of plastic pipes, which have lower emission rates than other piping materials, has contributed to the reduction of both $CH_4$ and $CO_2$ emissions in the distribution sector (EPA, 2018a). The low emission rates in the piping materials have been reflected in the low national distribution emission estimates from recent EPA GHGIs (2016 – 2018 editions).

A recent study analyzed emission trends for 2006 – 2015, using atmospheric $CH_4$ measurements from 20 North American sites (Lan et al., 2019). Lan et al. (2019) found no significant increase in emissions at most sites. Only modest increases were inferred only at three sites heavily influenced by oil and gas production, which shows a different trend found in the EPA's distribution sector emission estimate. While studies conducted in California's metropolitan areas show no evidence of decreased emissions from the PL and NG system (Peischl et al., 2013, Hopkins et al., 2016, Kuwayama et al., 2019), further studies in expanded regions of California including SJV will help verify the change in the emissions from the PL and NG systems (He et al., 2019). Particularly, quantification of changes over time in the fugitive emissions from the production and distribution sectors will help identify priority in mitigating climate change and monitor progress in mitigation.

In summary, we updated spatially explicit bottom-up estimates of $CH_4$ emissions from California's oil and gas production, transmission, processing, and distribution sectors using more recent EPA's emission factors. Using unified methods and datasets, we also developed gridded natural gas-related $CO_2$ emissions while we generated gridded $N_2O$ emissions based on US EPA's GHGRP. Notably, we developed a high resolution (1 km) gridded natural gas consumption map to estimate distribution and consumption emissions. This new consumption map is a significant improvement over previous studies (e.g., Jeong et al., 2014; Maasakkers et al., 2016), which relied on a moderate (~10 km) resolution population map as a proxy for consumption. We also developed gridded emissions from post-meter consumption of natural gas in residential and commercial subsectors, which have not been accounted for in previous spatial inventories. These new developments are important because current EPA's GHGRP does not include many large point sources such as oil and gas production fields (Duren et al., 2019), and post-meter fugitive emissions are not estimated in EPA's GHGI. Development of gridded emissions for the NG and PL systems are essential for many GHG quantification applications such as measurement-based top-down analysis because CARB's state inventory only provides aggregated emissions at the sector level. The updated $CH_4$ emissions from this work could be useful in evaluating EPA's recent emission factors when they are used in top-down analysis. The new $CO_2$ gridded emissions will provide useful information to assess long-overdue $CO_2$ emissions specific to California's natural gas-related emission sources.

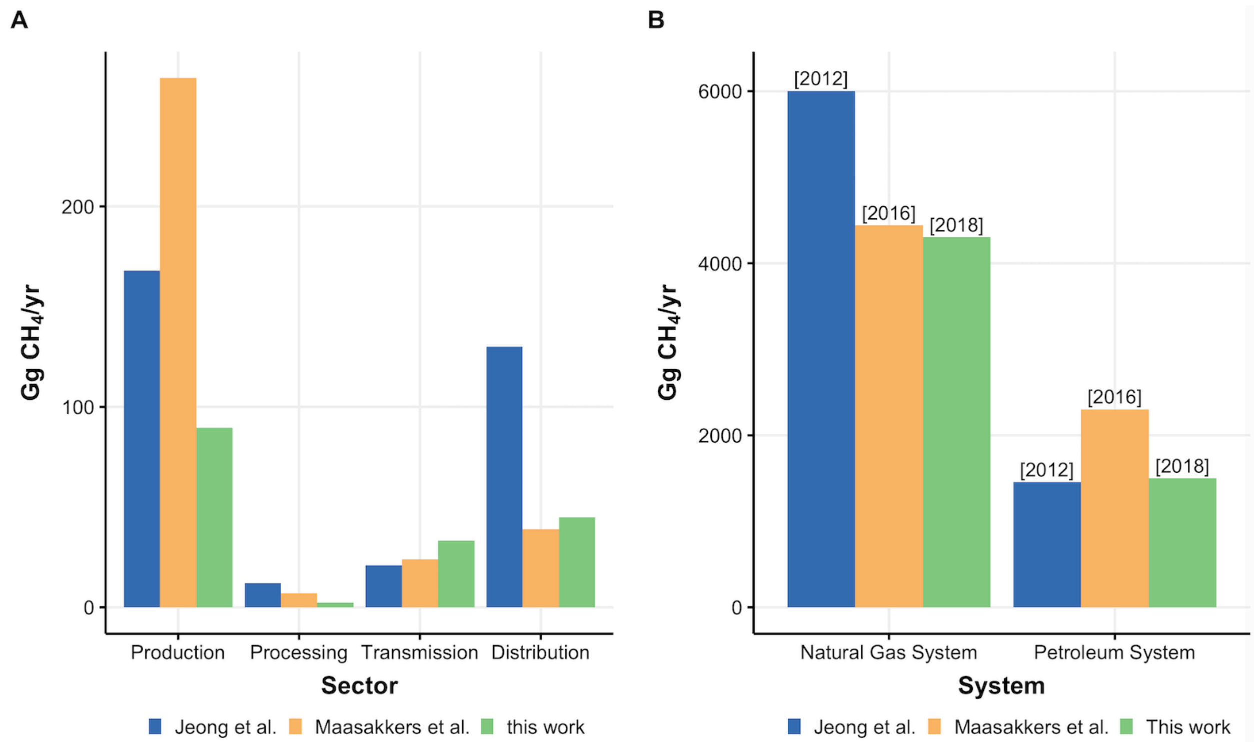


**Figure 9**. Comparison of estimated annual $CH_4$ emissions and US EPA inventories: (A) Comparison of estimated annual $CH_4$ emissions by sector and study and (B) EPA's US total $CH_4$ emissions for the production sector by system and study. The number on top of each bar in (B) indicates the year when the EPA GHGI corresponding to each study was published. Note that Jeong et al. (2014) estimate emissions for 2010 based on the 2012 EPA GHGI and Maasakkers et al. (2016) estimate 2012 emissions using the 2016 GHGI.

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# Appendices

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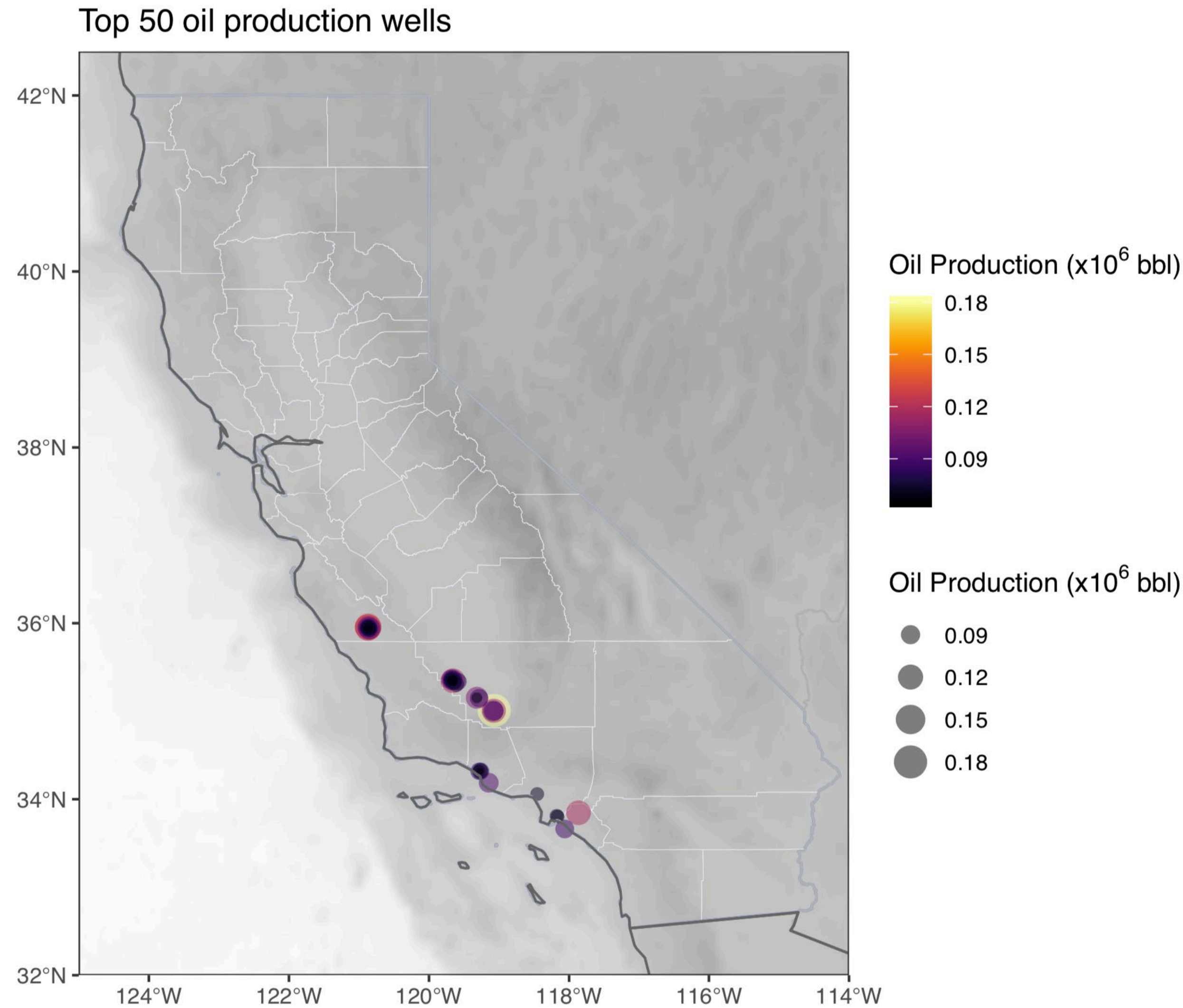
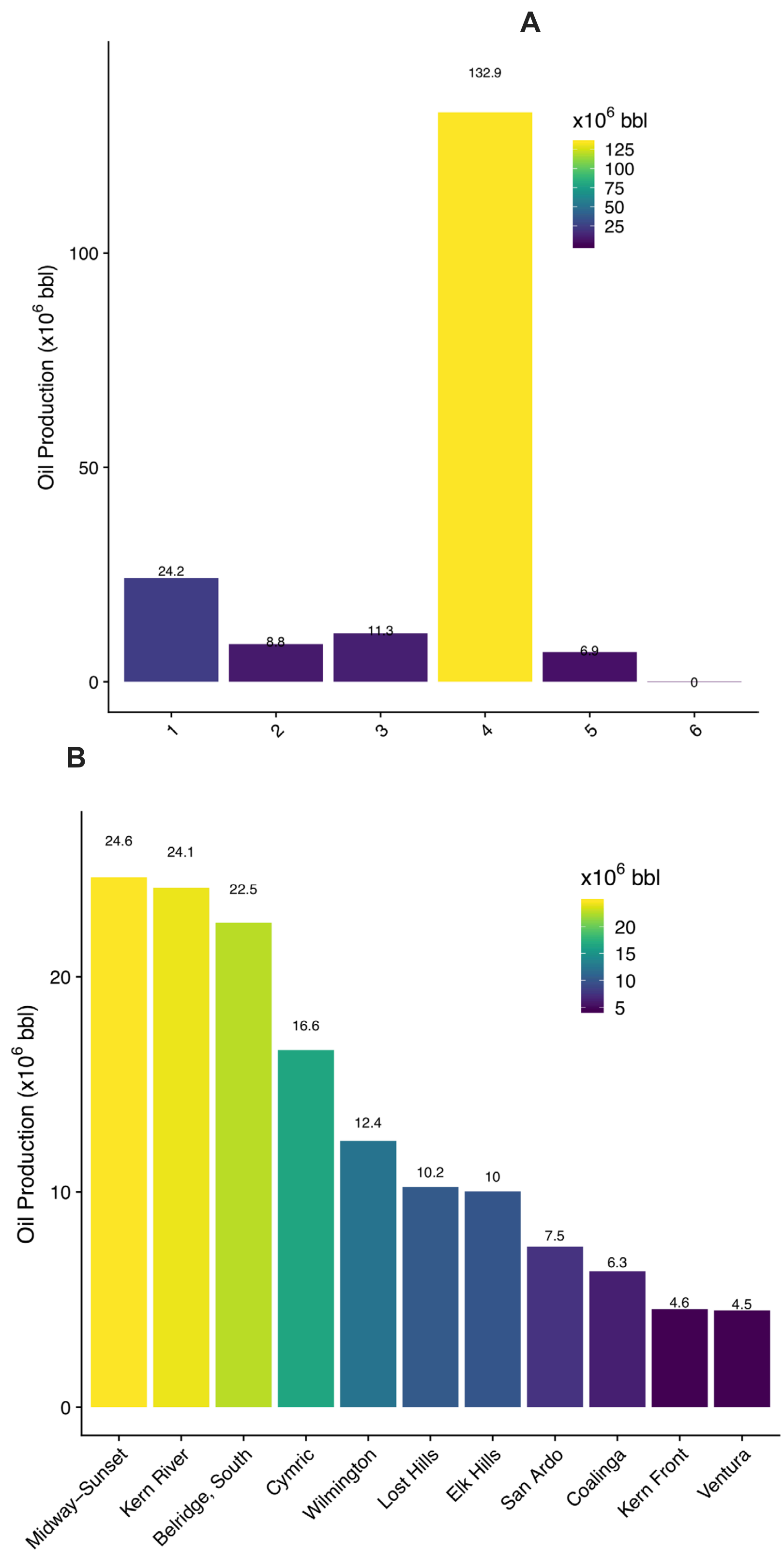
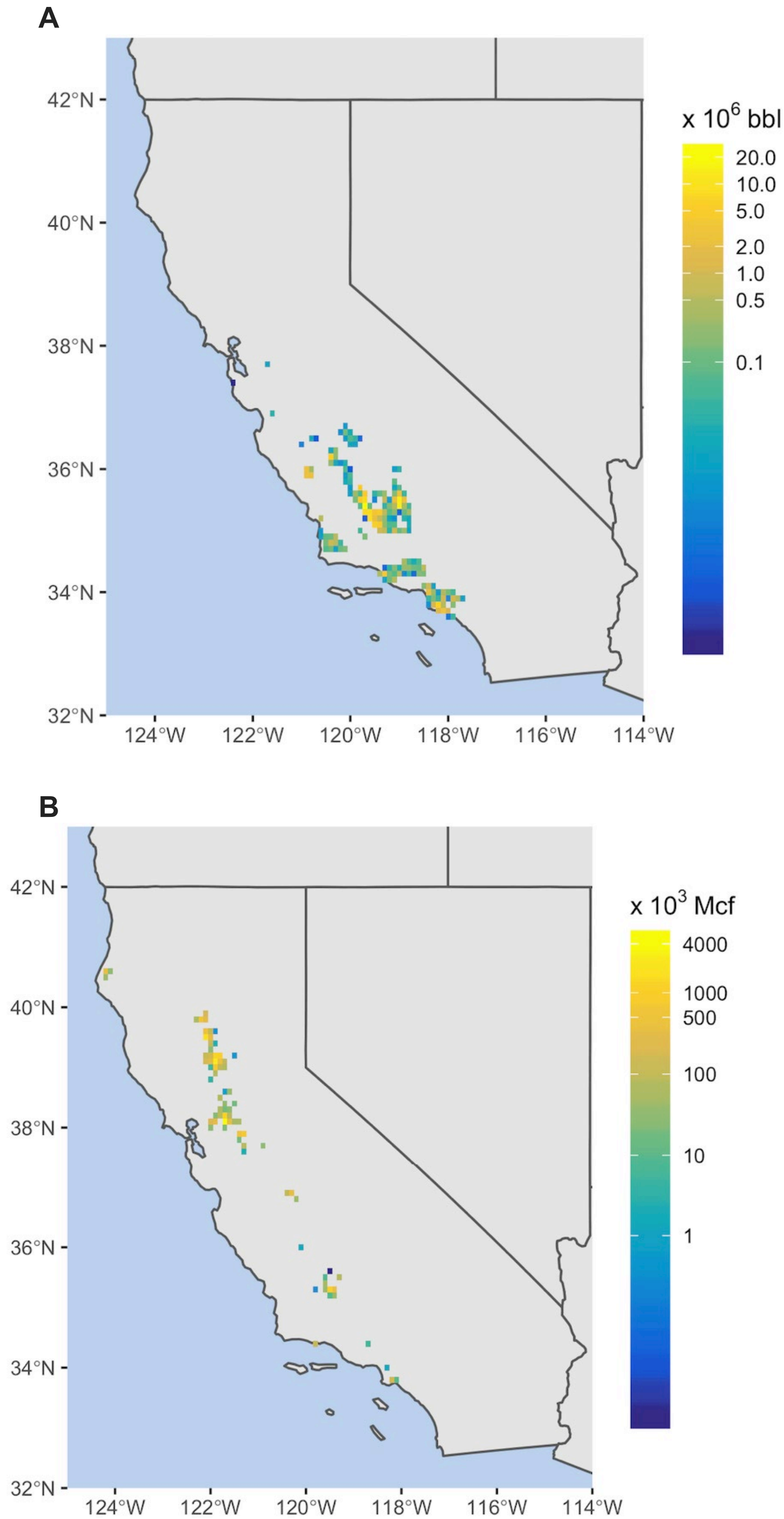
## A. Production



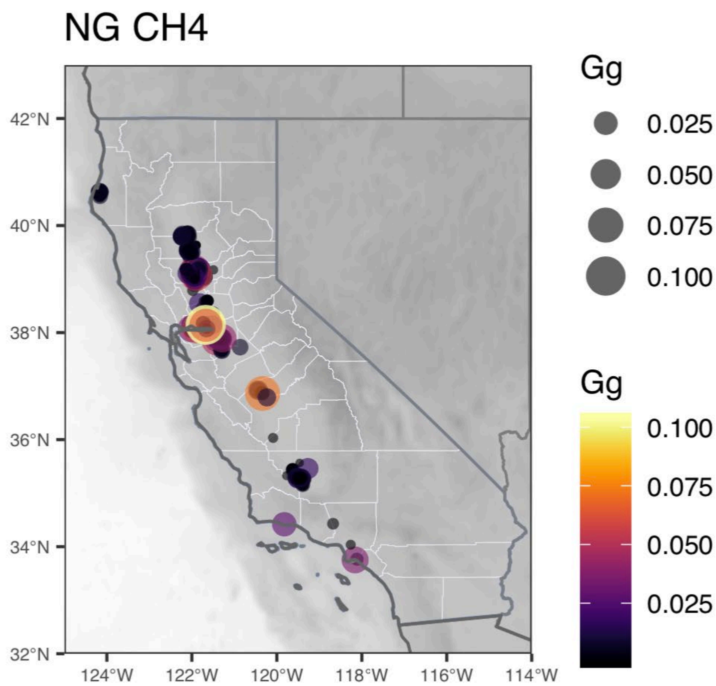

A1. Top 50 oil-producing wells in California.

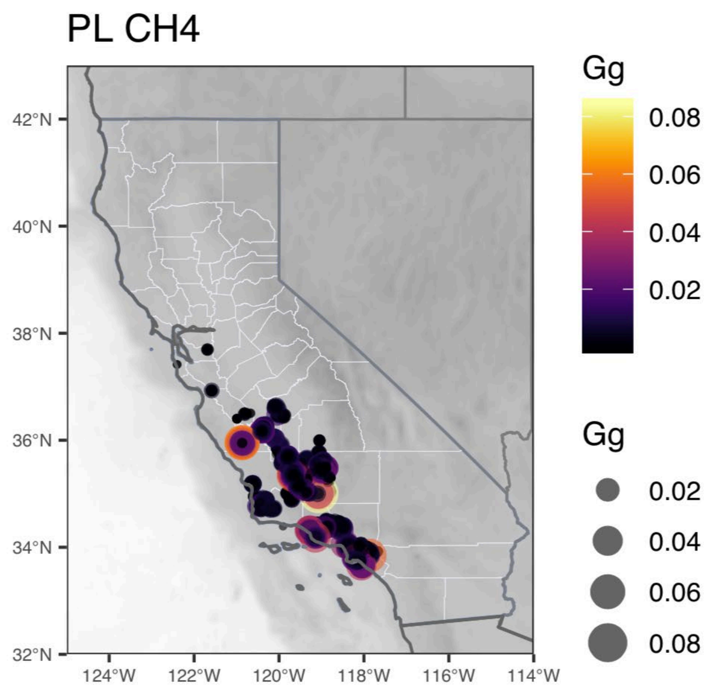



A2. (A) Oil production by DOGGR region and (B) Top 11 oil-producing fields for verification of the processed DOGGR database.

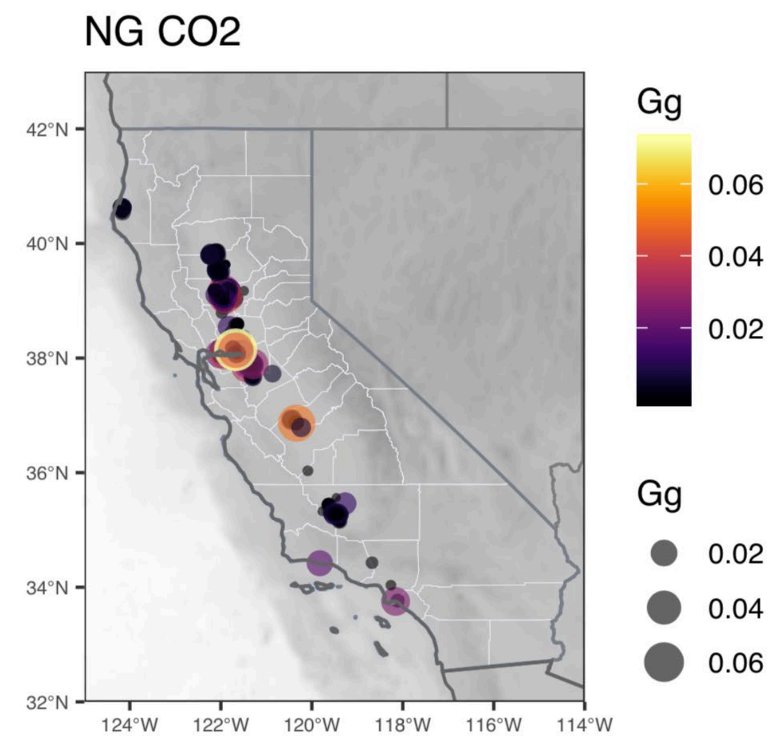


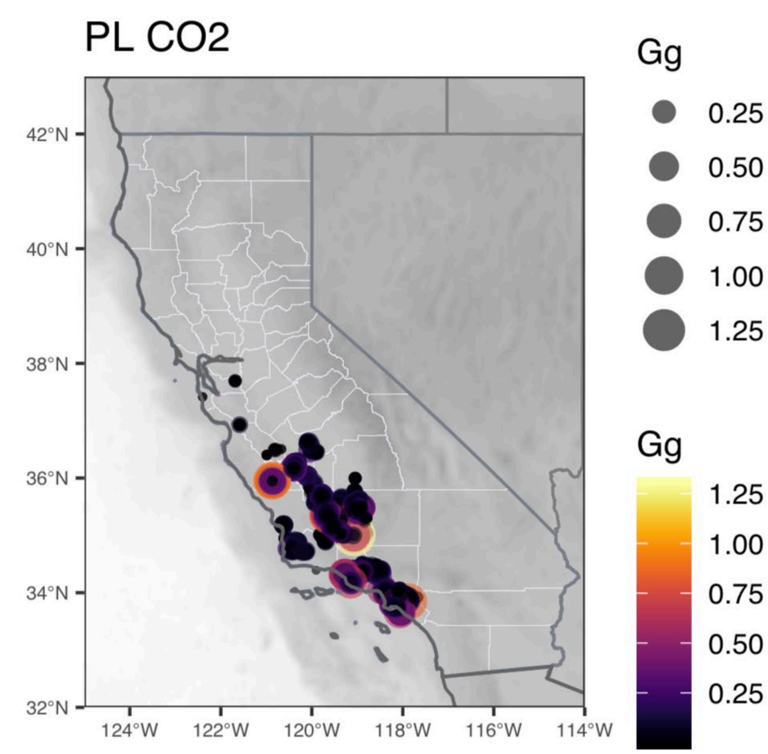

A3. Gridded oil production (units = $10^6$ barrel) for 2016 at 0.1° (~10 km). Gridded dry gas (from non-associated wells) production for 2016 at 0.1° (~ 10 km) resolution (units = $10^3$ Mcf; Mcf = $10^3$ cubic feet).



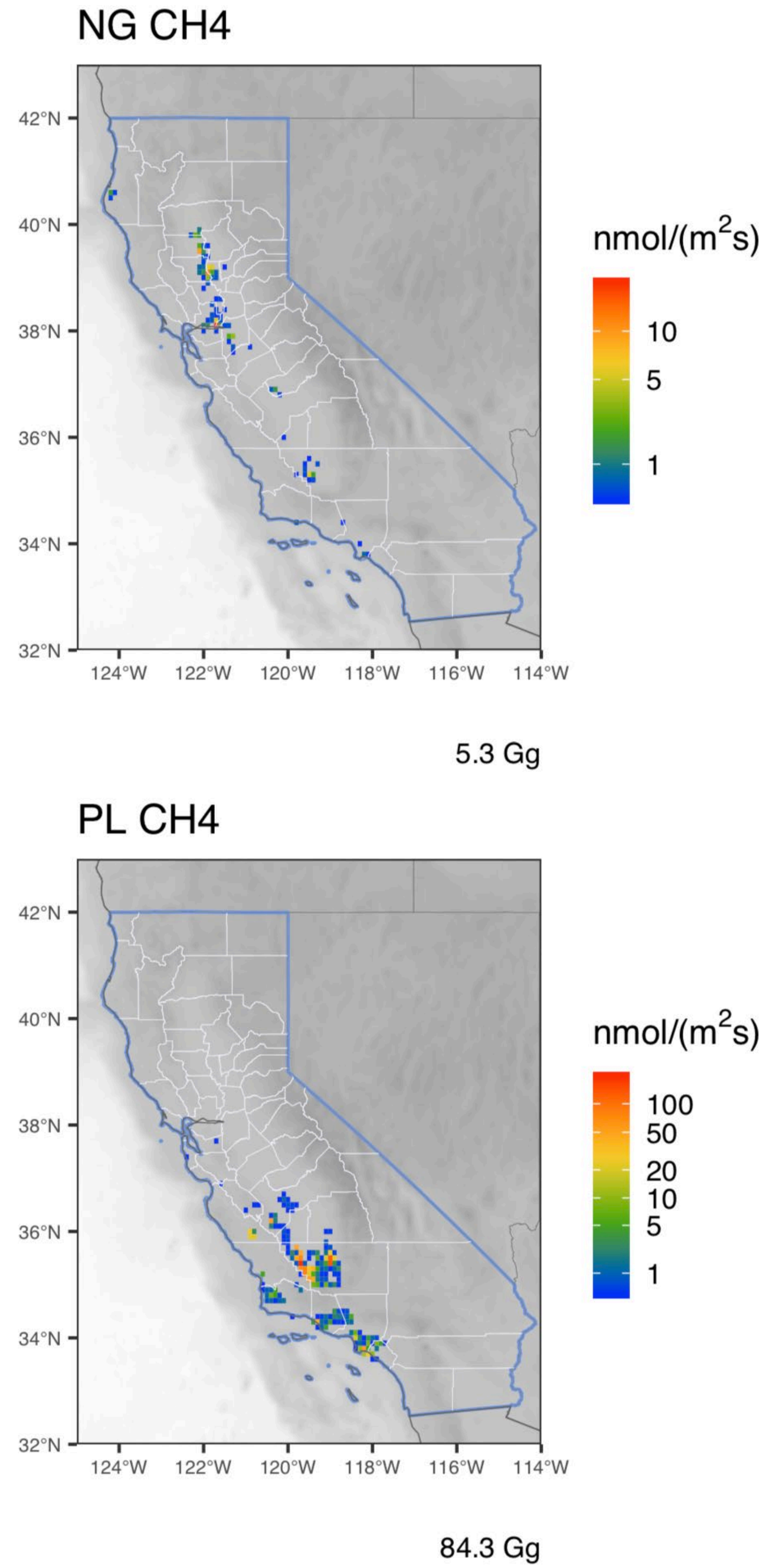




A4. Well-level $CH_4$ emissions (fugitive, flared, and vented) from the NG and PL systems.

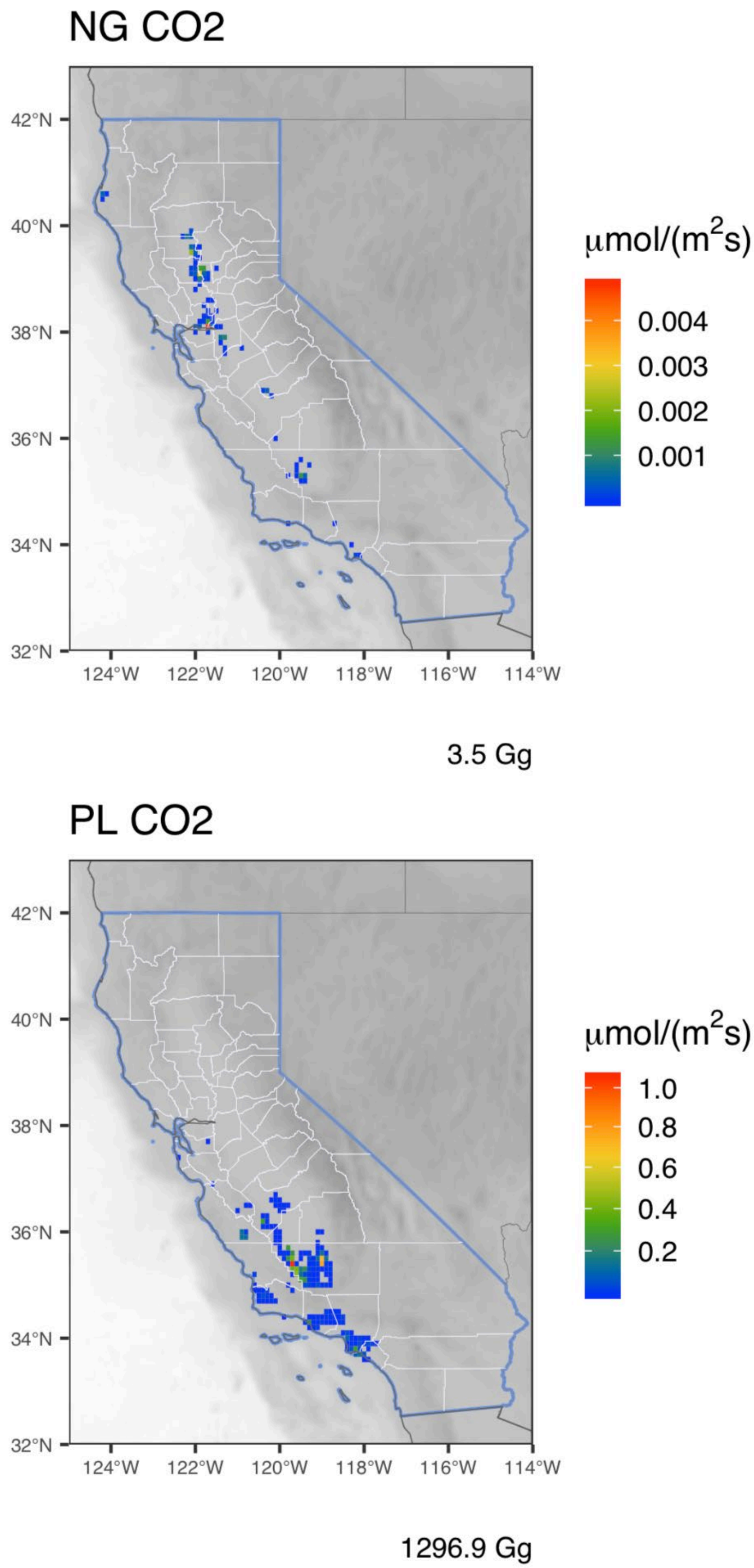


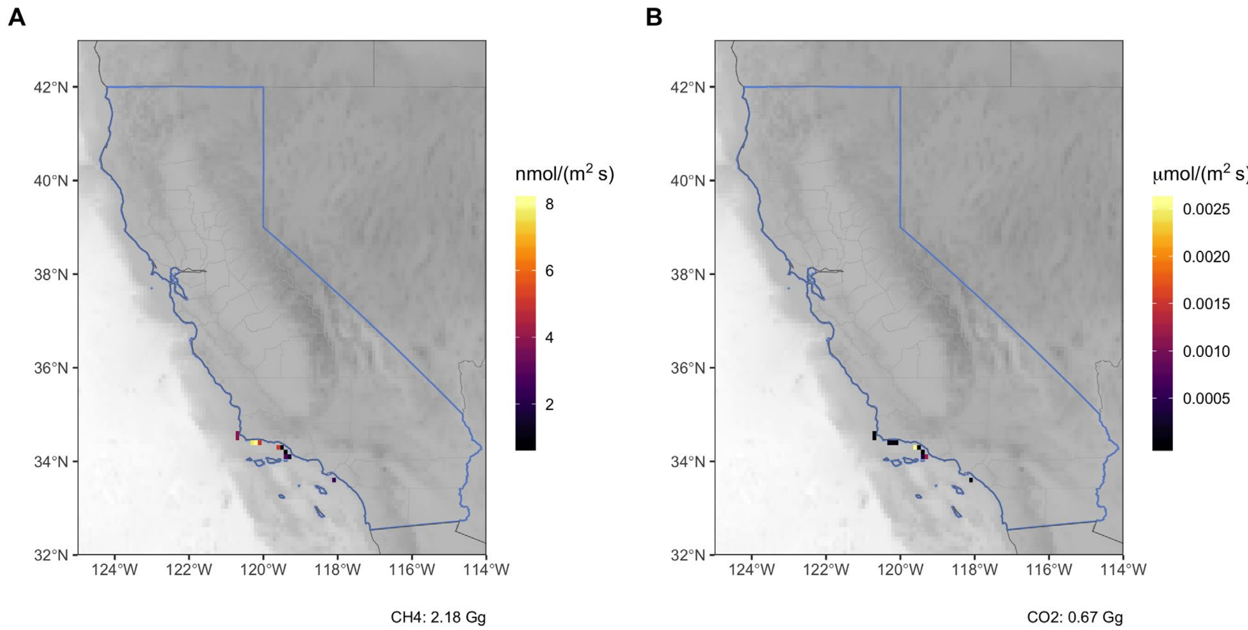

A5. Well-level non-combustion $CO_2$ emissions from the NG and PL systems.




A6. Gridded fugitive, flared, and vented $CH_4$ emissions (0.1° × 0.1°) from the NG and PL systems.




A7. Gridded fugitive, flared, and vented $CO_2$ emissions (0.1° × 0.1°) from the NG and PL systems.




A8. Estimated offshore $CH_4$ and $CO_2$ emissions (0.1° × 0.1°).

Fuel consumption for oil and gas production and processing and estimated $CO_2$ emissions

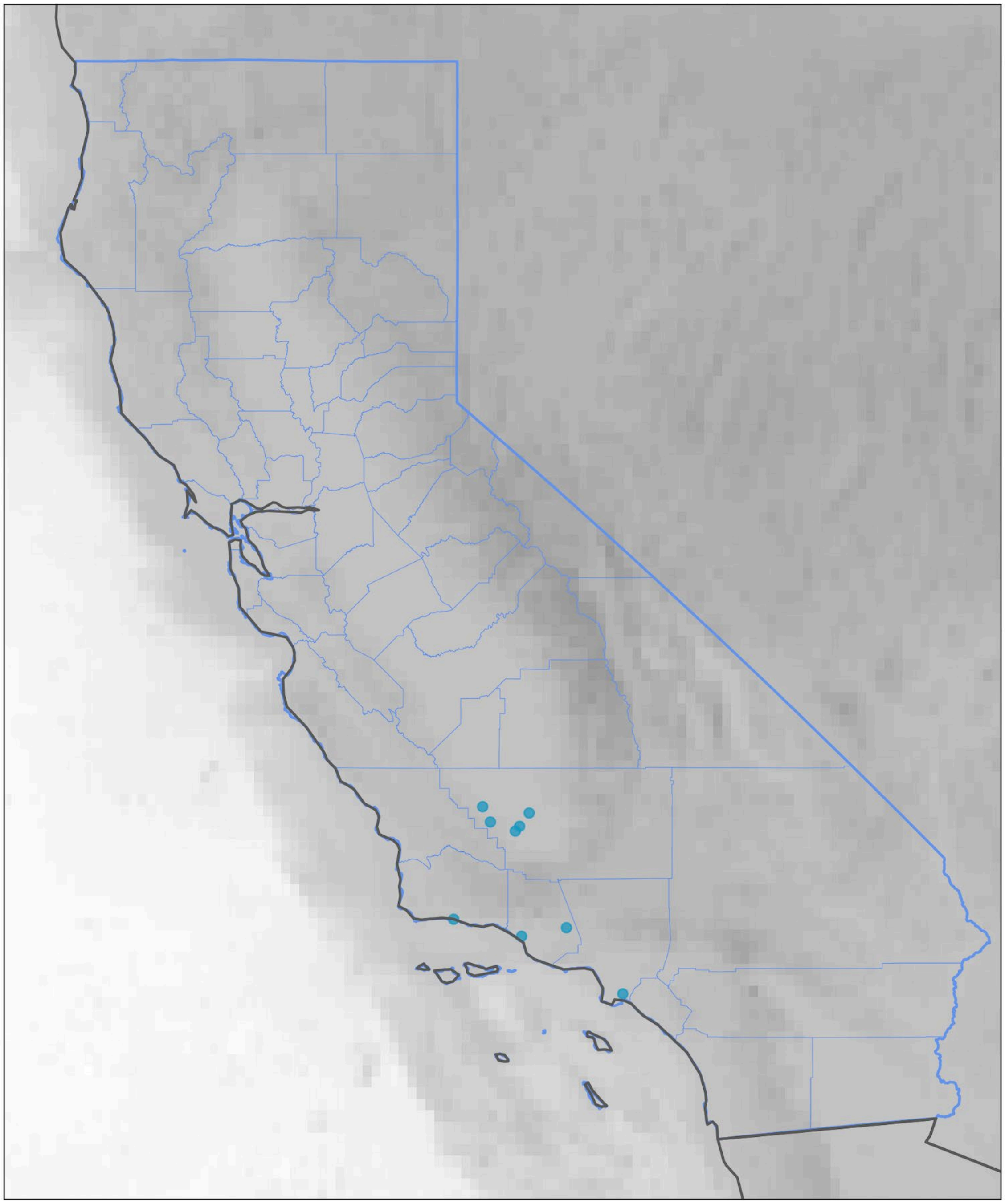
| Fuel Type | Consumption | Consumption Units | mmBtu* per gal / scf | kg $CO_2$ per mmBtu | kg $CO_2$ | Tg $CO_2$ |
|---|---|---|---|---|---|---|
| Distillate | 6.44E+06 | gal | 0.141 | 74.08 | 6.73E+07 | 0.07 |
| Natural gas | 2.72E+11 | scf | 0.001 | 53.06 | 1.48E+10 | 14.81 |
| Residual fuel oil | 0.00E+00 | gal | 0.145 | 74.02 | 0.00E+00 | 0.00 |
| Total | | | | | | 14.88 |

*mmBtu = one million British Thermal Units.

Fuel consumption for oil and gas production and processing and estimated $CH_4$ emissions

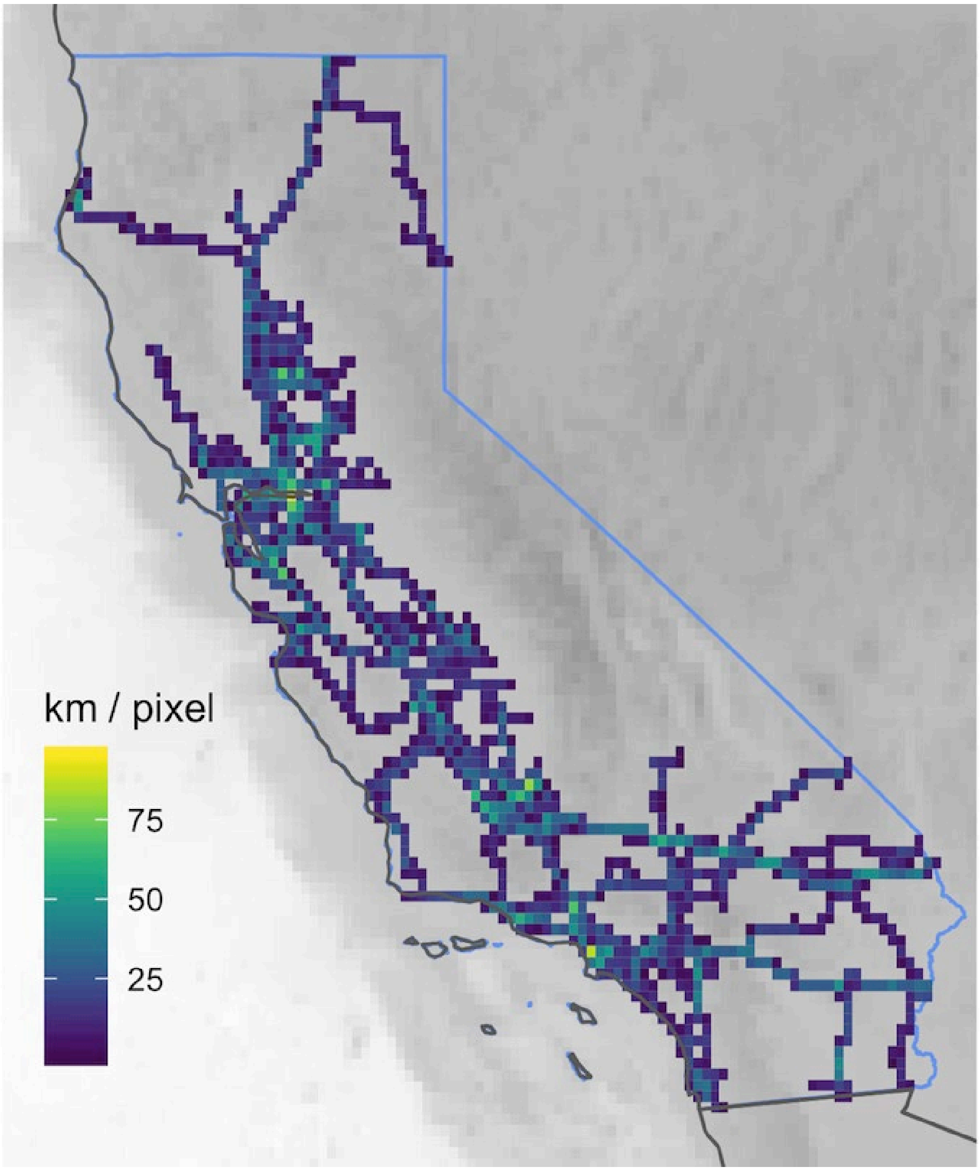
| Fuel Type | Consumption | Consumption Units | mmBtu per gal / scf | g $CH_4$ per mmBtu | g $CH_4$ | Gg $CH_4$ |
|---|---|---|---|---|---|---|
| Distillate | 6.44E+06 | gal | 0.141 | 3.0 | 2.72E+06 | 2.72E-03 |
| Natural gas | 2.72E+11 | scf | 0.001 | 1.0 | 2.79E+08 | 2.79E-01 |
| Residual fuel oil | 0.00E+00 | gal | 0.145 | 3.0 | 0.00E+00 | 0.00E+00 |
| All fuel | | | | | | 2.82E-01 |

## B. Processing

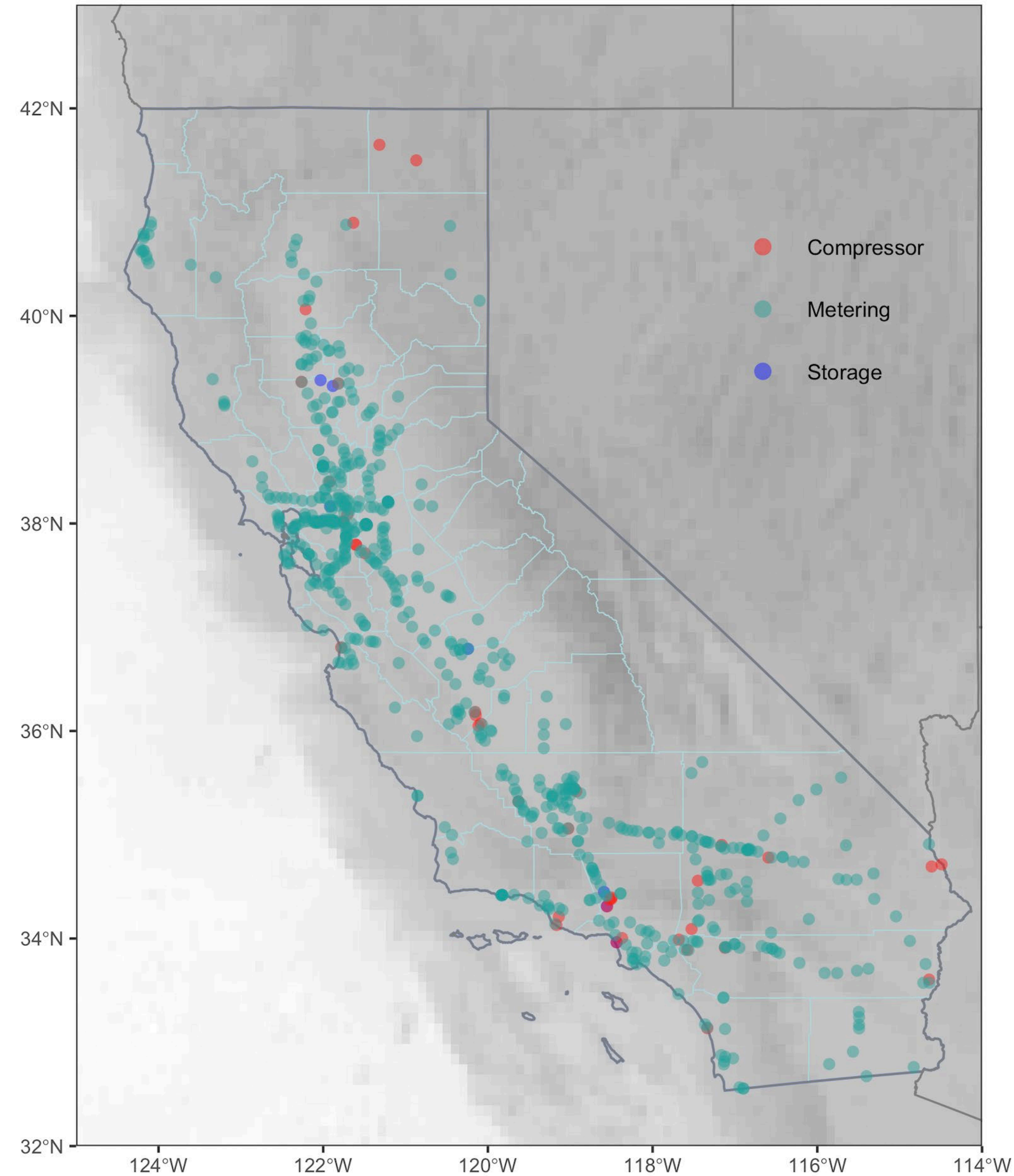


B1. Individual locations of natural gas processing facilities in California.

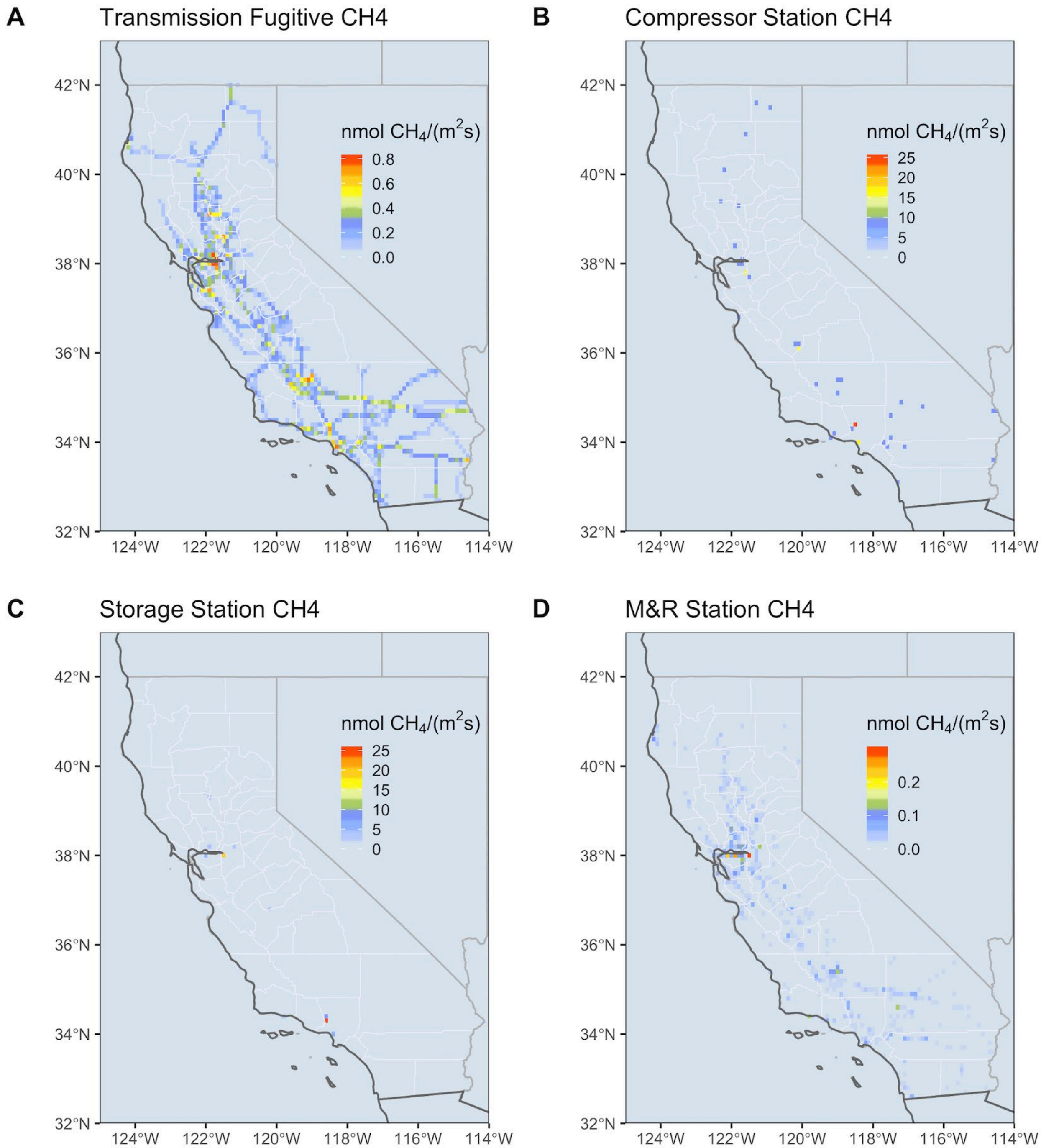
## C. Transmission




C1. Gridded map of pipeline length (km) at 0.1° (~ 10 km). Pipeline length is calculated for each of the 10-km pixels across California.

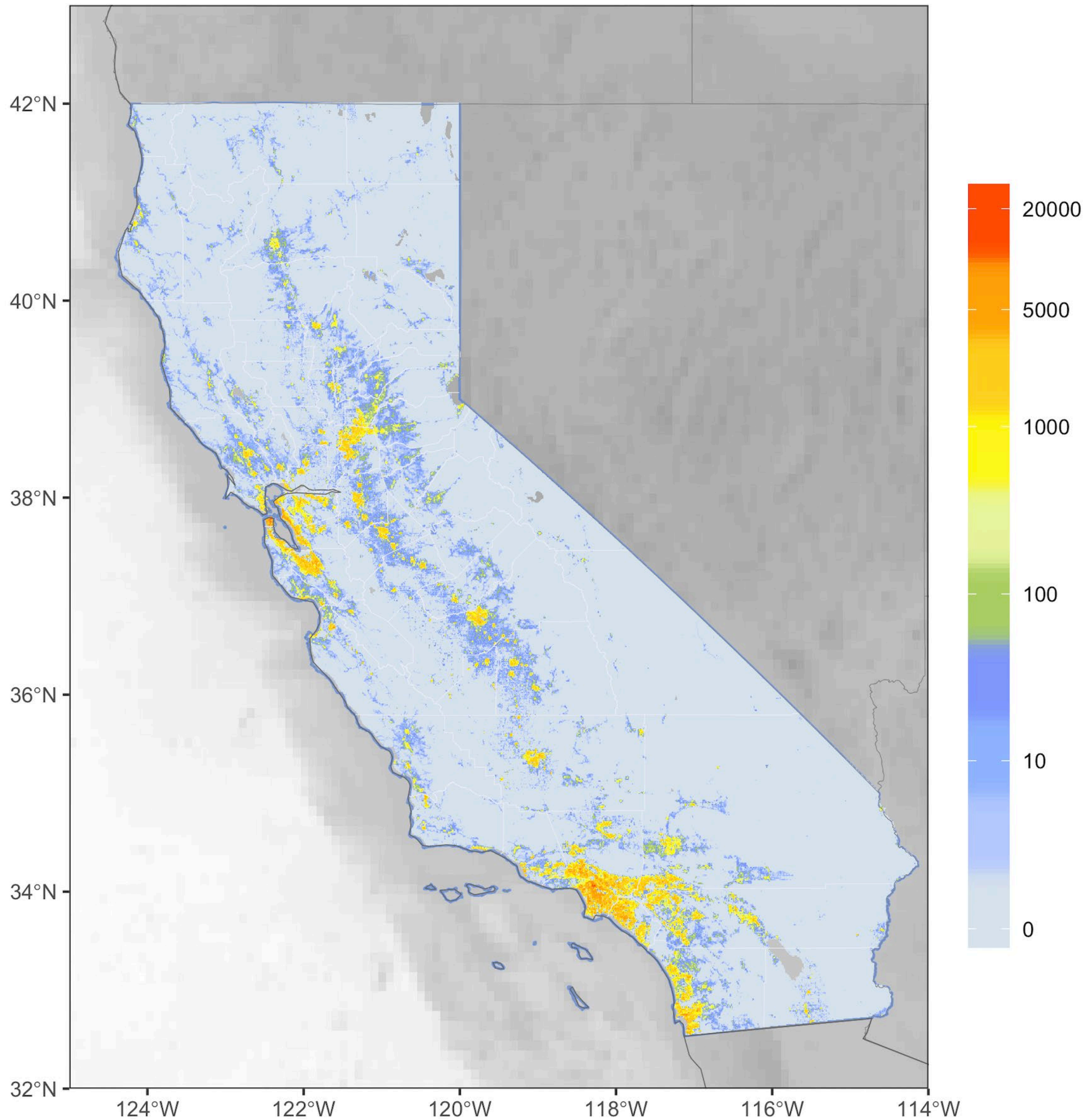



C2. Locations of individual compressor, metering and storage stations.




C3. Transmission $CH_4$ emission (fugitive, vented, and flared) maps by subsector. Emissions in (A) include all other fugitive, flared and vented emissions other than compressor, metering and storage stations.

## D. Distribution



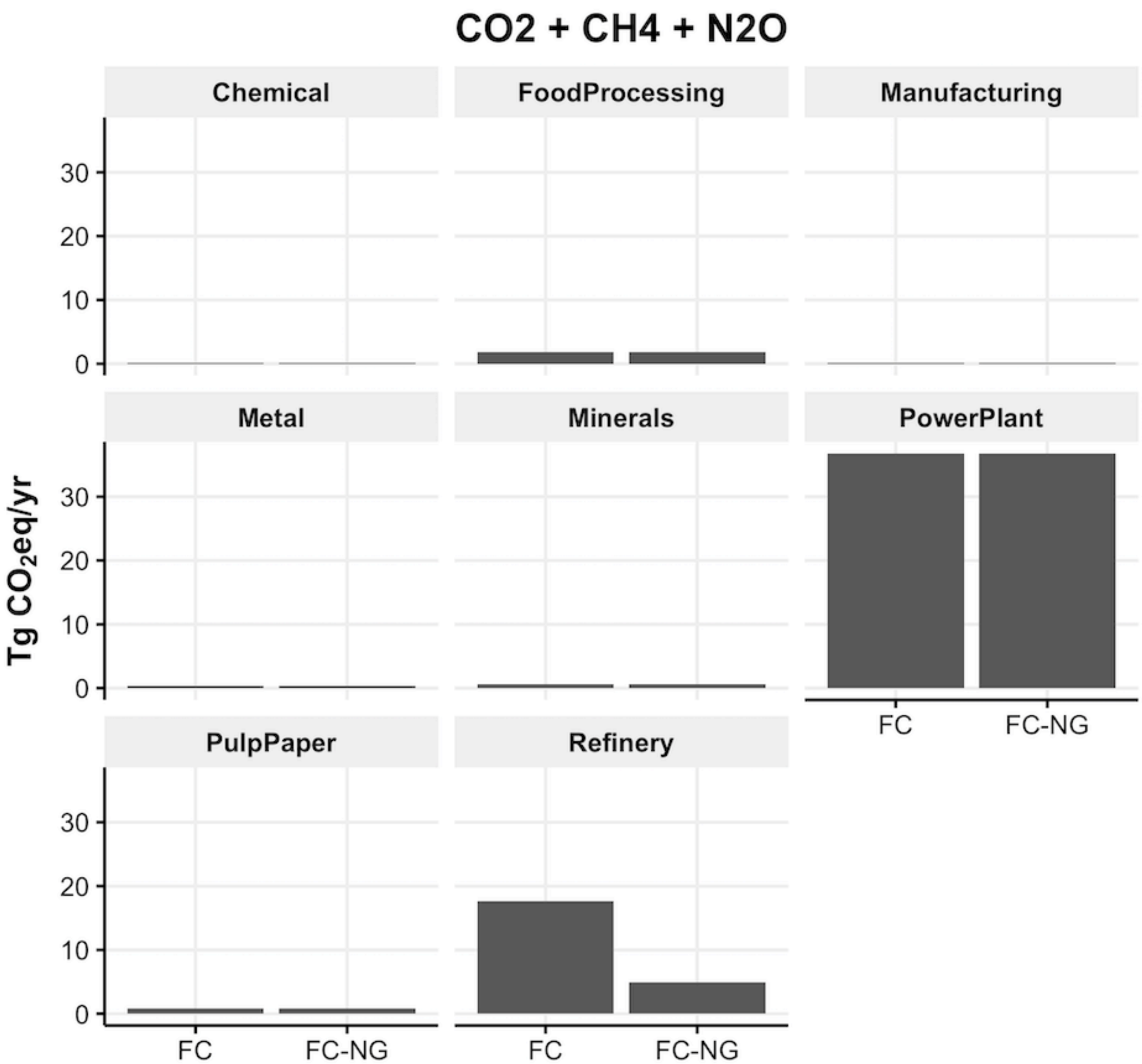

D1. Gridded population map (0.1°) of California for 2016. Population density is used as a proxy for natural gas distribution emissions.

## E. Consumption

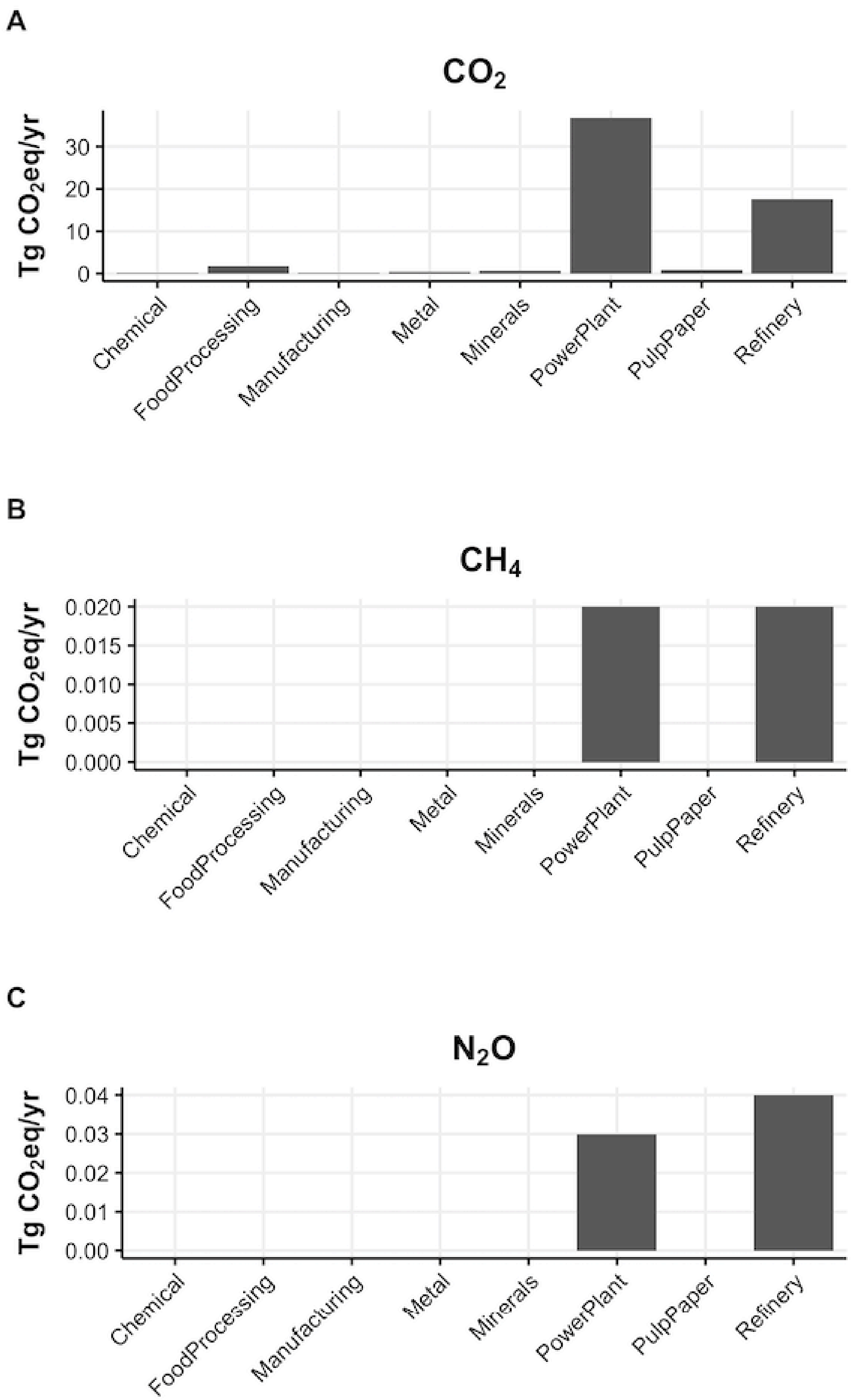
Summary of 2016 emissions for post-meter consumption based on EPA GHGRP

| GHG | Tg $CO_2$eq/yr* |
|---|---|
| $CH_4$ | 0.04 |
| $CO_2$ | 58.33 |
| $N_2O$ | 0.08 |

*Represents the total emission for each GHG from fuel combustion including natural gas. For included subsectors see Table 1 in the main text.




E1. Combined emissions for $CH_4$, $CO_2$ and $N_2O$ by fuel type from 2016 EPA GHGRP. The acronyms refer to fuel combustion (FC) of all fuels (including natural gas and petroleum products), and that solely of natural gas (FC-NG), respectively.




E2. Emission sums for fuel combustion by economic sector as designated in the EPA GHGRP.