Title
A Discussion on the Future of Natural Gas in California

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Publication Date
2018-06-01

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Issues with Emissions Quantification Boundaries, Potential of Renewable Natural Gas Sources, and Quantification of Lifecycle Fugitive Methane Emissions

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Abstract

California has long been a leader in climate change policy and is confronted with regulation to decrease greenhouse gas emissions 40% below 1990-levels by 2030 and a goal to reduce emissions 80% below 1990-levels by 2050. To reach these goals, there are options which the State is considering putting resources towards now in order to meet these goals in the future. This paper focuses on the question of the future of natural gas in California; particularly, how leakage from the natural gas system might increase the climate change impacts from the use of the fuel depending on how boundaries are drawn in the analysis, and gives insight into the options California is considering to reducing emissions from the natural gas segment.

The rate of leakage of methane from natural gas extraction is likely higher than assumed in national inventories. A lifecycle leakage rate for natural gas delivered to California of 3.6% [2.4 – 4.3]% was found through a literature review. This rate of leakage is detrimental to the climate and as such it is imperative the State looks towards decarbonizing the natural gas system from all angles. The State has decided to promote strategies such as Renewable Natural Gas (RNG) within Cap-and-Trade, though there are complications in using multiple methods of emissions accounting that will be discussed in this paper. As technologies are in the piloting phase, these complications and discrepancies are not particularly detrimental, but as these technologies start to scale, the accounting methods used may overestimate reductions under Cap-and-Trade. Finally, this paper discusses current issues involved with decarbonizing the natural gas sector from both a supply and land competition perspective. California must decide between heavily subsidizing emerging technologies in low-carbon gas technologies such as power-to-gas and hydrogen pipelines, or heavily subsidizing end use electrification and grid updates as to ensure climate change mitigation options do not cause equity issues; as such, issues such as emission reduction accounting under Cap and Trade and supply potentials are of utmost importance to understand.

Introduction

Methane is an extremely powerful climate pollutant. The IPCC quantifies methane to warm the atmosphere 36 times more per gram of the pollutant than carbon dioxide when analyzed over a 100-year timeframe. This timeframe is used to compare all greenhouse gases, as to understand long-term climate impacts. However, methane historically has survived in the atmosphere for closer to 12-years, and as such the warming potential is increased over its actual lifespan. While a 12-year global warming potential is not available through the IPCC, a 20-year timeline is analyzed over which methane warms the planet 86 times more per gram of the pollutant than carbon dioxide (IPCC 2013). Methane is primarily oxidized by the hydroxyl radical. Essentially all methane is converted into formaldehyde before being converted into carbon dioxide, where is stays in the atmosphere for centuries more. Methane is the primary component of natural gas and, when leaked, is released to the atmosphere as methane, but when combusted for end use or flaring, is released to the atmosphere as carbon dioxide. As climate change continues to impact communities across California and the world, society may need to consider analyzing emissions based on their actual atmospheric lifespans as opposed to analyzing long-term climate impacts using a global warming potential over 100-years.

California's primary source of energy comes from natural gas, which comprises 51% of the building energy sector and 31% of energy use across all sectors (including transportation) (EIA 2015a, EIA 2015b). California produces only about 9% of the natural gas used by the state and therefore imports the majority of the natural gas used (EIA 2016a). The California Greenhouse Gas Inventory (CA GHGI) and correlating Cap-and-Trade system currently only addresses in-state emissions with the exception of direct electricity imports, and therefore does not capture the extraction, production, and transmission emissions from the 91% of natural gas that is imported. Depending on how much natural gas leaks before arriving at the end user for combustion, this could lead to a substantial increase in emissions from the use of the fuel. This method of greenhouse gas accounting, termed an “end use method” or “production method” has merit – if each state accounts for and reduces the emissions that occur within their boundaries, where they ultimately have jurisdictional authority, there would be no need to assess emissions outside of state bounds. However, energy is inherently cross-jurisdictional and methods California is looking to employ to reduce emissions may not correspond with this accounting methodology.

Regardless of what the State decides regarding the development of RNG, understanding how much methane leaks from natural gas systems is of importance to greater climate change policy. Studies have revealed that if 2% of natural gas leaks before being combusted for end use, to the climate benefit from the use of natural gas instead of coal is negated (Wigley 2011). Additionally, understanding lifecycle emissions from natural gas systems could lead to more productive means of greenhouse gas mitigation due to the high global warming impact of methane over its short lifespan. Reductions of methane and other short-lived climate pollutants could prove to be an effective way to slow the rate at which humans are changing the climate and potentially put off the triggering of larger momentum feedbacks or nonlinearities in the climate system.

This paper aims to address multiple dilemmas when it comes to reducing emissions from natural gas. **Section 1** discusses how boundaries are set for California’s Greenhouse Gas Inventory and Cap and Trade as compared to methodologies for the Low Carbon Fuel Standard and discusses how they promote or inhibit certain approaches to greenhouse gas mitigation. **Section 2** discusses how these emissions could be mitigated by the use of RNG and other low-carbon fuels, and details current issues with the emission reduction potential. **Section 3** attempts to bring together the latest research on methane leakage from natural gas systems that deliver the fuel to California. Finally **Section 4** concludes with policy opportunities for the State.

Section 1: Current Issues with Greenhouse Gas Accounting and Boundary Setting

Greenhouse gas mitigation strategies can be shown to have different emissions reductions depending on the boundaries of the greenhouse gas accounting method. Emissions in California are quantified similar to most inventories, using a “production-based” methodology, where emissions are attributed to each segment of the production line. For natural gas, the end-use combustion emissions are attributed to the end-user (residential, commercial, or industrial energy use). Fugitive emissions from any in-state processes (transmission, distribution, storage, compression and the emissions from extraction and processing for ~9% of demand) are attributed to the industrial sector. The remaining 91% of extraction, processing, and transmission process emissions are excluded from greenhouse gas accounting as it occurs outside of state lines. **Figure 1** below shows a diagram of generally how emissions quantification is divided or excluded.

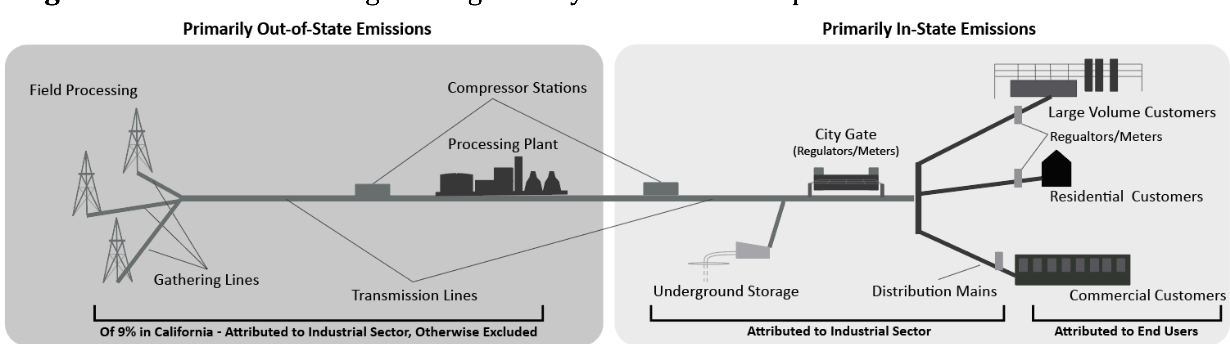


Figure 1: Lifecycle of Natural Gas with Emissions Boundaries

While a production-based inventory is a theoretically sound accounting mechanism from a broad perspective as discussed earlier, there can be misunderstandings when it comes to calculating state- or sector-specific emissions reduction potential. For the case of RNG, methane is captured from sources that would typically emit the methane to the atmosphere and processes the methane into pipeline-quality natural gas to transport to the customer. Emissions from end-use combustion remain the same as do fugitive emissions from the in-state distribution of the gas. The real benefit to the use of RNG is seeing a reduction in methane emissions at the original source (landfills, wastewater treatments plants, dairies, etc.) and also reducing methane emissions associated with extracting fossil natural gas.

As shown in **Figure 1,** the majority of emissions calculated by California and within the Cap and Trade system come from the downstream processes. Emissions reductions can be seen from in-state methane producing sectors, though this opportunity is fairly limited. To put this in context, **Figure 2** shows California's greenhouse gas emissions in terms of natural gas. Natural gas combustion emissions comprise 32% of the State's greenhouse gas emissions, which, using RNG, will not be eliminated. Fugitive emissions from in-state natural gas transportation and the limited in-state production contributes to 1% of the State's greenhouse gases, which may be in part reduced through RNG though the majority of estimated fugitives from transporting the gas would need to be reduced from other measures. The methane-producing industries in the state (landfills, composting, WWTPs, dairies) have the potential to be almost fully avoided using RNG, though only constitute 8% of the state's greenhouse gas emissions.

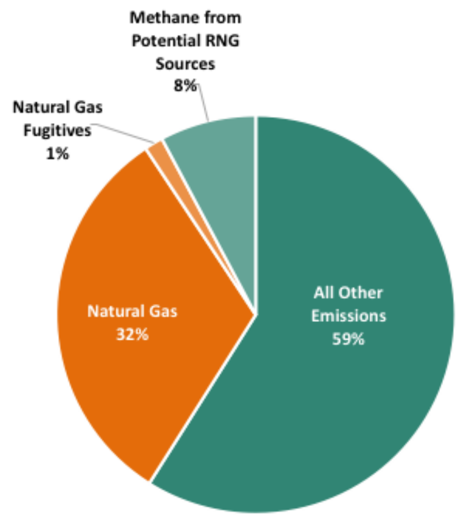


Figure 2: California GHG Emissions

The California Air Resources Board (CARB) currently exempts any RNG use under Cap and Trade. What this does is essentially gives the use of RNG an emission factor of zero for end-use combustion, and allows utilities to not pay allowances on the use of the fuel. They then give additional offset credits to the anaerobic digestion source, for example, the dairy where the methane was captured for the fuel. This was done as a way to promote the use of RNG as the State is still piloting programs where methane can be captured from other sectors. With the amount of RNG currently used in the state, the discrepancy caused from the inaccuracy of calculating the emissions reduction will likely not cause too much of a difference with respect to credits and value pertained from RNG use under Cap and Trade. This is likely true even if the maximum RNG was created from in-state methane capture sources from existing sectors, as that potential is such a small portion of California's demand (as discussed in **Section 3**). Instead, where this will start to matter is if utilities decide to increase RNG use by importing additional biomethane or planting energy crops for gasification as with both the scaled use as well as primarily seeing out-of-state reductions, using a zero carbon intensity for RNG end use will no longer be an acceptable rough estimate of emissions and the use of RNG in those cases might be given a higher mitigation monetary value through Cap and Trade allowance exemptions than would be accurate.

The Air Resources Board has already faced this issue with the use of biofuels for the transportation sector and had to start using a lifecycle emissions accounting system for the Low Carbon Fuel Standard. A lifecycle emissions accounting system takes care to include all emissions from the extraction/production of the fuel through the final end use/tailpipe emissions, and attributes all emissions per unit to a unit purchased of the fuel. If the state does start to employ energy crop gasification technologies and import biomethane, it is likely that CARB will have to move towards a lifecycle accounting methodology for decarbonized gas as well. To note, where RNG has seen a steady rise due to market forces surrounding greenhouse gas regulation is in the transportation sector (Jaffe 2016). This is likely attributed to the fact that the Low Carbon Fuel Standard uses a lifecycle accounting method to quantify greenhouse gas emissions as it provides an economic incentive, through a credit, to both displace petroleum fuel and capture and destroy methane emissions from other sectors. Additionally, it allows for out of state avoided methane emissions to be counted as long as the RNG is physically entered into a pipeline connected to California and used as a feedstock that produces a vehicle fuel (ARB 2016).

Section 2: Renewable Natural Gas Potentials for California

RNG adoption to date has been limited to areas where it makes economic sense without the push from Cap-and-Trade, or to the transportation sector due to the credits received from the lifecycle analysis method associated with the Low Carbon Fuel Standard. An example of an area where RNG makes economic sense without incentives would be methane from a wastewater treatment plant being captured and used to power that same wastewater treatment plant. In fact, of the 90.3 – 116 billion cubic feet per year (BCF/y) of anaerobically digested potential RNG supply within the state, California already uses 37 BCF/y (Parker 2017, ICF 2017).

When looking at RNG potentials, let us first analyze anaerobic digestion sources. These are the most environmentally preferable methods as it includes the capture of methane which would otherwise be released to the atmosphere and therefore adds a double benefit to the reduction of extracting fossil gas. **Table 1** looks at a range of RNG potential supplies found in recent studies. These estimate RNG from California resources can produce 4 – 5% of California's natural gas demand (Parker 2017, ICF 2017). Brining in the potential from energy crops, using California-only supply we can increase the RNG potential to 7-8% of California demand. Using all of the US supply potential of energy crop RNG, there is quite a range in the literature, spanning from 28 – 398% of California demand. While the Department of Energy (DOE) does estimate the higher end of energy crop potential, it is important that the state considers the competition for such fuels if it decides to take that path. Specifically, that the use of land to grow energy crops may increase the price of food or even crowd out food crops (Rathman 2009). Additionally, energy crops may be better used for hard to electrify fuels such as diesel and jet kerosene. A California-specific study found that if all the sustainable biomass, 94 million tones in this study, were used for the transportation sector, California would still fall short of cutting transportation emissions by 32%, indicating a need to electrify the transportation sector as well (Wei 2013). This indicates the need to look at these options from an economy-wide perspective and understand how mitigation options in one sector could affect the potential to mitigate in others.

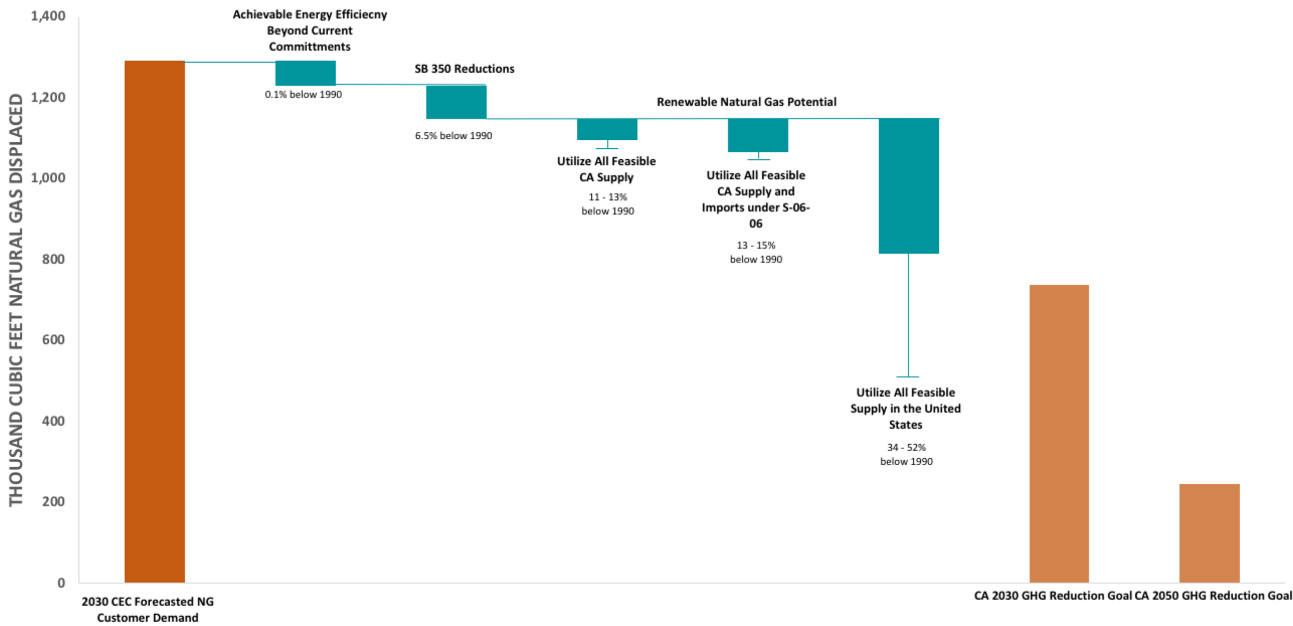
Table 1: Potential RNG Supplies from Anaerobic Digestion and Energy Crops

Study	Percent of CA Demand that can be supplied by Anaerobic Digestion Sources	Percent of CA Demand that can be supplied by Digestion plus Energy Crop Gasification
California-only Supply		
Parker et al 2017 (Arizona State and Davis)	**4%** [90.3 BCF/y; **1.7%** 37.3 BCF/y already used]	N/A
ICF Study (incorporates AGF, & DOE in range)	**5%** [101 - 116 BCF/y]	**7 - 8%** [145 - 181 BCF/y]
Using Full United States Supply		
Parker et al 2017	**15% - 39%** [333 BCF/y Technically Feasible; 855 BCF/y Gross Potential]	N/A
AGF	**18 - 48%** [390 - 1040 BCF/y]	**28 - 72%** [610 - 1558 BCF/y]
NREL	**35%** [756 BCF/y]	N/A
DOE	**10-26%** [212 - 562 BCF/y]	**46 - 398%** [1000 - 8668 BCF/y]

Figure 3 on the following page then shows the fossil natural gas that can be displaced through energy efficiency as well as three RNG scenarios: using all CA demand, using all California demand plus the maximum

amount California can import under S-06-06, and finally using all of the potential US supply for California demand. The maximum displacement of fossil gas using captured methane sources, under S-06-06 limitations, and including energy efficiency reductions from SB 350 as well as any additionally achievable reductions considered by the CEC to be feasible by 2030, would be 13 – 15% below 1990 levels.

Figure 3: California Fossil Natural Gas Displacement Potential using Energy Efficiency and RNG



Section 3: Lifecycle Leak Rate Estimation of Natural Gas Supplied to California

As analyzing lifecycle emissions from the energy sector may be an analysis direction California choses to go, this paper brings a first attempt at estimating a lifecycle leakage rate from natural gas that is consumed by California end users. The need for an analysis of lifecycle methane leakage from natural gas that is imported to California has been documented through AB 1496 which became law in 2015 requesting the California Energy Commission (CEC) to do such analysis. While the CEC has published their findings from in-state leaks, an analysis has yet to be completed for imported gas. As such, another bill, AB 2195, has been proposed which would require the state to quantify and report an inventory of lost gas from natural gas imported to the state from out-of-state sources.

While more directed research is needed in this area, this section attempts to bring together the latest research on methane leakage along the lifecycle of natural gas systems specifically supplying California demand. It is, of course, recommended that methane leakage remain an active area of research and should undergo more coordinated efforts to understand lifecycle leakage nationally, as well as leakage in regions that supply certain markets as to allow for incorporation into greenhouse gas reduction programs. This type of research will soon be necessary to guide the State in transitioning from calculating in-State emissions to calculating lifecycle emissions from the energy sector within the CA GHGI and Cap and Trade markets. However, regardless of the pathway to decarbonization California chooses, a greater understanding of lifecycle emissions of natural gas will be necessary for the energy-sector implementation of RNG as well as to hone in on the most productive means of greenhouse gas mitigation. The remainder of this paper will be focused on bringing together the latest research on fugitive methane emissions from natural gas systems that supply California's natural gas demand. While understanding full lifecycle emissions must include more than just fugitive emissions, the fugitive emission aspect is generally the least accurately quantified.

Emission Factor Background

Lack of understanding and accuracy in emission factor estimations of natural gas has led to a profound discrepancy between atmospheric measurements of methane concentrations and what is reported in our greenhouse gas inventories. On a national scale, atmospheric measurements have found that methane levels increased 35% from 2002 – 2014 (Turner 2016). Using this metric, by 2014 the US Greenhouse Gas Inventory (US GHGI) would underestimated methane emissions by approximately 24 million metric tons of methane, or 84% (US EPA 2016a, Turner 2016). If we include this to the US GHGI, the nation's greenhouse gas emissions would increase by 25%. Further, if using a GWP over 20 years, the entire US GHGI would increase by 55%.

While the unaccounted-for source of additional methane in the atmosphere has been argued, NASA recently confirmed that the increase in methane emissions is linked primarily to natural gas extraction (Worden 2017). This conclusion generally agrees with changes in methane-producing industries over the same time period as well, favoring natural gas production as likely the main emitter. Between Turner's study years of 2002 – 2014, natural gas production increased 30% (EIA 2016b), livestock production increased 9% (DOA 2016), and compost, wastewater treatment plants, and landfill emissions decreased by 2% (US EPA 2016b).

The U.S. Environmental Protection Agency estimates leak rates of methane from natural gas along the lifecycle of the gas to be approximately 1.4%, though recent scientific studies using a variety of techniques including air campaigns, literature reviews, bottom-up studies, remote sensing, and mass-balance approaches have estimated leak rates on a national scale to be between 2.0 – 12% indicating large unknowns and likely regional differences (Burnham 2011, Brandt 2014, Howarth 2012, Miller 2013, Coulton 2014, Howarth 2015).

Method

This paper brings together the best-available science to estimate the methane leak rate along the lifecycle of the natural gas that is delivered to California for end use. The studies selected are basin-specific, peer reviewed studies of regions which most closely match the basin in which California pipes in gas from. Natural gas fugitive emissions did not become an area of very active scientific research until the fracking boom. As such, there are limited peer-reviewed first-hand studies on the subject, especially from basins serving California. Regardless, at least one peer-reviewed primary study was found for each basin, the exception to this being only the Permian basin in which only a literature review by Carnegie Mellon was found which differentiated emissions to the particular basin. In the case where the basin had multiple studies from multiple years, the most comprehensive primary research was used. In some cases, older studies were verified using different methods of study. All studies are listed in **Appendix 1.** A summary of the leak ranges, percent of California demand supplied by the basin, and the study chosen is shown in **Table 2**. Leak rates from each production site was applied to the portion of gas that comes from each pipeline serving the stated basins. Proportion of gas supplied by each pipeline and correlating basin was found from utility reports to the 2017 California Gas Report. Emissions found from out-of-state basins were then added to the recent comprehensive review done by the CEC to estimate natural gas methane leaks within the California.

How Natural Gas Enters California

The California Gas Report gives the quantity of gas supplied to each utility by the pipeline. Basins served can be approximated by the quantity from each pipeline. **Table 2** below gives a summary of the pipeline quantities and basins served per the California Gas Report.

Table 2: Quantity of Natural Gas Supplied to California by Pipeline

Pipeline (MMcf/day)	California Sources	El Paso	Trans Western	GTN	Kern River	Mojave	Other	Ruby	Total
Southern California Gas Company	123	866	427	176	816	0	100	0	2511
Pacific Gas and Electric	33	238	184	1155	30	0	15	594	2249
Other Northern CA	12	0	0	0	0	0	13	37	62
Non-Utilities Served Load	429	0	0	0	697	14	0	0	1140
San Diego Gas and Electric	13	96	52	22	101	0	12	0	296
Southwest Gas	23	0	0	0	0	0	13	0	38
Totals	**633** (10%)	**1200** (19%)	**663** (11%)	**1353** (21%)	**1644** (26%)	**14** (0.2%)	**153** (2%)	**631** (10%)	**6296**
Basins		Permian, San Juan[1]	Permian, San Juan, Anadarko[2]	Western Canada, Rocky Mountain[3]	Southwest Wyoming[4]	Permian, San Juan[5]		Rocky Mountains[6]	

1. http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2015%20Summer%20Prep/EPNG-Kinder%20Morgan%20Summer%20Prep%20-%202015.pdf
2. https://www.energytransfer.com/ops_interstate.aspx
3. http://www.gastransmissionnw.com/index-archive.html
4. http://www.kernrivergas.com/About-Us/Overview
5. https://www.kindermorgan.com/business/gas_pipelines/west/EPNG_MP/
6. https://www.kindermorgan.com/pages/business/gas_pipelines/west/Ruby/default.aspx

Production Leak Rates from Basins that Deliver to California

Several interstate pipelines bring the remaining needed natural gas into California from the Southwest, the Rocky Mountain region, Western Canada, and the Western region with the most recent pipeline addition flowing from Wyoming (EIA 2018b). **Table 3** page outlines the leak rates of production sites that have been studied and supply California. The percent of gas flowing to California from each basin was found through utility reporting (California Gas and Electric Utilities 2017), with the exception of Western Canada which was found through EIA international gas imports data (EIA 2018c). Similarly, California well-leaks were assigned a corresponding portion of the 10% of the end use they supply based on each basin's total production. The primary studies used and any studies not used to determine the amount of methane leakage as a percent of basin production is disclosed in the "Leak Rate Source and Notes" column.

Table 3: Leak Rates of Production Zones Supplying California

	Portion of California Supply	Leak Rate Used (% of production)	Leak Rate Source and Notes	Total Production of Study Area (Billion Cubic Feet)
Permian	**13.0%**	2.2% [No Range]	**Presto (2017)** Carnegie Mellon Literature Review used as most specific to Permian Basin study found.	2,300
San Juan	**3.0%**	3.1% [2.6 – 3.5%]	**Kort (2014)** remote sensing study used – as range was given. Numbers corroborated by **Frankenberg (2015)** remote sensing study.	1,300
Anadarko	**13.0%**	1.6% [0.6 – 2.0%]	**Miller (2013)** aircraft and tower study used as range was given. Miller study looked at basins in Texas, Oklahoma, and Kansas and numbers found for each basin in the region approximated for Anadarko Basin. Numbers corroborated with **Presto (2017)** literature review.	1,500

Western Canada Montney Basin	**0.01%**	0.6% [no range]	**Atherton (2017)** vehicle-based survey study used. Only study of the region found.	951
Rocky Mountains Denver-Julesburg Basin	**31.5%**	4.1% [1.1 – 5.6%]	**Petron (2014)** airborne study was used as numbers were verified and honed-in-on in this study from the **Petron (2012)** study. However, the range includes the **Robertson (2017)** vehicle-based study. The **Robertson (2017)** study was not fully used because it was not as thorough as the Petron studies. The Zavala-Araiza study was not used either as it did not entail its own primary research.	600
Southwest Wyoming Pinedale Basin Upper Green River Basin	**26.0%**	0.38% [0.12 – 0.86%]	**Brantley (2014)** vehicle-based study used for Pinedale Basin and **Robertson (2017)** vehicle-based survey used for Upper Green River Basin. Midpoint approximated leak rate used for both basins, and range encompassing both studies used.	516
California	**10.0%**	*See Table 3*		
Other	**2.0%**	*Unknown mix – use emissions from remainder of supply*		

A weighted average of the leak rate per the portion of California supply by basin, would give a leak rate from out-of-state basins of 2.2% [1.0 – 2.9%].

Emissions in California

The California Energy Commission recently compiled a study in partnership with the Lawrence Berkeley National Lab to reconcile emissions inventories with atmospheric greenhouse gas measurements in terms of natural gas fugitive emissions, as there has been a large discrepancy both in California and nationally by reporting much lower methane emissions than what is measured in the atmosphere. **Table 4** gives a summary of the emissions determined by the study and the correlating leak rates – percent of production for in-state production leaks, and percent of consumption for all transportation processes in-state.

Leak rates from non-associated production are applied to 10% of the California's demand and is used within the leak rate estimation from production sites. Leak rates from associated wells are listed as an informational item only, as it can be easily argued that emissions from associated production would be primarily attributed to oil production. However, this study could be made better by attributing a certain portion of associated emissions to natural gas depending on the proportion of natural gas to oil supplied from the associated wells.

Table 4: Leak Rates from all in-State Natural Gas Sources

Process	Emissions Estimation [MT CH4/year]	Leakage Rate
Wells – Associated	172,000	5.2% [4.1 – 6.3%]
Wells – Non-associated	28,000 [20,000 – 36,000]	1.8% [1.3 – 2.3 %]
Processing	15,000	0.3% (Both associated and non-associated)
Transmission (Pipelines, Compressors, Metering)	30,000	0.07%
Storage Facilities	9,000	0.02%
Distribution Lines	288,000	0.68%
Residential Meters	130,000	0.31%
Total (Non-Extraction)	**472,000**	**1.4%**

Note: the CEC did scale up their leakage rate estimate for associated wells to include methane leak emissions found in the atmosphere attributed to natural gas that was not accounted for in the CA GHGI. However, for non-associated wells, the CEC did not scale the leak rate in the same way, and opted to disclose a leak rate as provided in the CA GHGI.

This paper estimates a lifecycle leakage rates attributed to natural gas end-use by adding the leak rate of 2.2 [1.0 – 2.9]% from gas wells with leaks from in-state source phases including gathering, processing, storage, transmission and distribution, and residential meter leaks, which add up to a 1.4% leakage. These additions give a total lifecycle leak rate for the use of natural gas in California of 3.6 [2.4 – 4.3]%. This range excludes emissions from California Associated wells and is therefore thought to be in the lower range of estimates as California associated gas leaks were excluded.

Policy Opportunities

As the Obama-era Methane and Waste Prevention Rule – a rule which would have updated the industries three-decade-old venting and flaring rules to better account for losses recognizing technological advances through fracking (BLM 2018) - was dismantled, it is now up to the State to determine ways to reduce leakage of natural gas both in-state and from gas supplied to the state. The following are a non-exclusive list of options for the State to consider:

- **SB 1371 Amendment:** Require utilities to disclose the rate of leakage from leaks found under SB 1371 instead of allowing utilities to rely on emission factors which have repeatedly been estimated to be too low.
- **Incorporate Lifecycle Emissions Intensity in Energy Comparisons within Building Code:** Require a lifecycle emissions estimate to be used within Title 24 when comparing the environmental effects of gas versus electric appliances.
- **Cap and Trade Valuation:** Shift to using a lifecycle emissions calculation similar to the Low Carbon Fuel Standard for energy resources under Cap and Trade. Also consider using a global warming potential factor over 20-years instead of 100-years to help incentivize the reduction of short-lived climate pollutants.
- **Incentivize Heat Pump Water and Space Heaters:** As RNG and energy crops are not expected to reduce the use of fossil natural gas by a percentage large enough to reach SB 32 reductions, electrification of most end uses is likely the default decarbonization option. However, electrification retrofits, depending on the home, can be expensive. As such, the State should provide incentives, rebates, and other cost-reducing mechanisms to promote electrification.
- **Renewable Natural Gas Prioritization:** Due to the limited supply of biomethane for RNG, the State should work to prioritize the use of RNG in sectors that are hard to electrify, such as high-heat industrial and heavy-duty trucking.

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Appendix 1: Production Leak Rate Studies

Leak Rate Summary: Production Sites Providing for California Demand										
Study	**Study Year & Type**	**Leak Rate and Range**	**Leak Rate**			**Emissions Estimate Raw Data**	**Production**			**Study Notes**
			Low Estimate	**Author's Estimate**	**High Estimate**		**Million Cubic Feet**	**Raw Data**	**Data Entity**	
El Paso, Trans Western, Mojave Pipelines										
Permian Basin										
Presto (2017) Permian Basin	2015 Lit Review	**2.2% [no range given]**		2.2%			2,300,000	2300 BCF produced in 2015	Study	Lit Review by Carnegie Mellon
San Juan Basin										
Frankenburg (2016) San Juan Basin, Four Corners Region	2015 Remote Sensing	**3.1% [no range given]**		3.1%		0.59 Tg CH4/y		1.3 Trillion Cubic Feet production (or 19.2 Tg CH4) in 2009	Study	Super-emitters found 0.59 Tg CH4/y emitted Found primarily due to natural gas extraction, however coal mines are also in the area
Kort (2014) San Juan Basin, Four Corners Region	2003-2010 Remote Sensing	**3.1% [2.6 - 3.5%]**	2.6%	3.1%	3.5%	0.59 Tg CH4/yr [0.5 - 0.67 Tg]		1.3 Trillion Cubic Feet production (or 19.2 Tg CH4) in 2009	Study	0.59 Tg CH4/yr [0.5 - 0.67 Tg] Emissions persistent since 2003, indicate from established fossil fuels systems
Anadarko Basin										
Miller (2013) Texas, Oklahoma, Kansas	2007 - 2008 Aircraft and Tower Measurements with Transport Model	**1.3% [0.6% - 2.0%]**	0.6%	1.3%	2.0%	3.7+/-2.0 Tg CH4/y	9,111,399		EIA	Global: Aircraft analysis: 32.4 +/- 4.5 TgC/y for 2004 Regional Oil & Gas Emissions = 3.7+/-2.0 Tg C/y "Texas, Oklahoma, Kansas Region" split between Anadarko, Permian, Ft Worth, and West Gulf Coast Basins (see Fig 1) For purposes of this study - found leak rage over all three states and assumed same leak rate for the 2 basins that send gas to California
Presto (2017) Anadarko Basin	2015 Lit Review	**1.6% [no range given]**		1.6%			1,500,000	1500 BCF produced in 2015	Study	Lit Review by Carnegie Mellon
GTN and Ruby Pipelines										
Western Canada Basin										
Atherton (2017) Montney Basin	2015 Vehicle-Based Surveys	**0.6% [no range given]**		0.6%		111,800 MTCH4	951,174	26934233.26 thousand cubic meters	British Columbia NG Reports	Monteney Develoment Studiesd - approximately 55% of BC's gas production CH4 emissionestimate of 111,800 tonnes per year
Rocky Mountain Basin										
Zavala-Araiza (2015) Allocation based on Previous Literature	2011 Based on Allen et al	**0.6% [no range given]**		0.6%		3869 Mg CH4		629578 Mg NG	Study	Methane emissions allocaated to natural gas (separated from that allocated to oil) from Rocky Mountain Wells = 2175Mg (dry) and 1394 (liquids) Total Estimated Utimate Recovery = 363904 Mg (dry) and 265,674 (liquids)
Petron (2012) Denver-Julesburg Basin	2007 - 2009 Vehicle-Based Survey	**4.0% [2.3% - 7.7%]**	2.3%	4.0%	7.7%	251 (71.6 - 129.6) Gg/y				
Petron (2014) Denver-Julesburg Basin	2012 Airborne Study	**4.1% [2.6 - 5.6%]**	2.6%	4.1%	5.6%	19.3 +/- 6.9 tons CH4/hr				
Brantley (2014) Denver-Julesburg	2010 - 2013 Vehicle-Based Survey	**1.36% [0.97 - 1.95%]**	0.97%	1.36%	1.95%					
Presto (2017) Denver-Julesburg	2015 Literature Review	**2.6% [no range given]**		2.6%			600,000	600 BCF produced in 2015	Study	Lit Review by Carnegie Mellon
Robertson (2017) Denver-Julesburg	2014 Vehcile-Based Survey	**2.1% [1.1 - 3.9%]**	1.1%	2.1%	3.9%					
Kern River Pipeline										
Southwest Wyoming										
Brantley (2014) Pinedale	2010 - 2013 Vehicle-Based Survey	**0.58% [0.39 - 0.86%]**	0.39%	0.58%	0.86%					
Robertson (2017) Upper Green River	2014 - 2015 Vehicle-Based Survey	**0.18% [0.12 - 0.29%]**	1.1%	2.1%	3.9%					

Leak Rate Summary: California Processes										
Study	**Study Year & Type**	**Leak Rate and Range**	**Leak Rate**			**Emissions Estimate Raw Data [Gg CH4/y]**	**Production**			**Study Notes**
			Low Estimate	**Author's Estimate**	**High Estimate**		**Million Cubic Feet**	**Raw Data**	**Data Entity**	
Wells - Associated	2010	**5.3% [4.2 - 6.4%] for all phases of assocated production to distribution**	4.20%	5.30%	6.40%	172	193,800	3.69 Tg/year of 193.8 billion cubic feet associated production	CEC - Study	196Gg/3.69Tg = 5.3 +/-1.1% leaked from associated production. 4.7% for assiciated production only
Wells - Nonassociated	2010	**1.8% [1.3 - 2.3%]**	1.30%	1.80%	2.30%	28 [20 - 36]		1.58 Tg/year dry gas production	CEC - Study	only using bottom up estimate, not scaling per Peichel, ==> team got 1.8% leakage (28Gg/1.58 Tg production)
Processing	2010	**0.30%**		0.30%		15				
Transmission Pipelines	2010	**0.70%**		0.07%		30		42,475 Gg NG Consumption	EIA	Percent of consumption (2,328,504 Million Cubic Feet)
Storge Facilities	2010	**0.20%**		0.02%		9		42,475 Gg NG Consumption	EIA	
Distribution Lines	2010	**0.68%**		0.68%		288		42,475 Gg NG Consumption	EIA	
Residential Meters	2010	**0.31%**		0.31%	0.3%	130		42,475 Gg NG Consumption	EIA	