Gas Planning and Reliability in California

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Introduction

The State of California has set ambitious climate goals that require significant reductions in greenhouse gas (GHG) emissions across the state. Meeting these goals—which call for 40 percent reductions from 1990 emissions levels by 2030 and statewide carbon neutrality by 2045—will require deep and transformative changes across all sectors. The focus of this paper is on California's gas system, which is estimated to have contributed approximately 26 percent of statewide emissions in 2018 (CARB 2020).

California's gas system currently supplies gas for a diversity of critical uses across the state. Natural gas fulfills heating needs in residential households, serves industrial uses, provides baseload electricity generation, and enables the balancing of renewable energy in the state's electricity system (CPUC 2021a). Decarbonizing these end uses will take time due to their extent and complexity. In the meantime, California's gas system also faces increasing pressures from climate change (e.g., changes in demand, as well as thermal stress, flooding, and ground subsidence (Bruzgul *et.al.* 2018, Oruji *et.al.* 2019, AghaKouchak *et.al.* 2020)), public and regulatory scrutiny following safety-related incidents (CPUC 2020a), and concerns related to health impacts from indoor residential gas use (Zhu *et.al.* 2020).

In the building sector, electrification has been identified as a major strategy to reduce GHG emissions. However, even under a high-electrification scenario, millions of customers are still expected to rely on the gas system in 2050 (Aas *et.al.* 2020). Decarbonizing the electricity sector will require increasing reliance on renewable energy and large-scale deployment of electricity storage technologies, including for long-duration storage (Childs 2020). As these strategies are implemented, the safe and reliable operation of the gas system, as well as its affordability to customers (Sieren-Smith *et.al.* 2021), is of paramount importance.

In January 2020, the California Public Utilities Commission (CPUC) issued an Order Instituting Rulemaking (OIR) to establish policies, processes, and rules to ensure safe and reliable gas systems in California and to perform long-term gas system planning (R.20-01-007, see: CPUC 2020a). Tracks 1A and 1B of this rulemaking are underway and focus on reliability standards and market structure and regulations, respectively. Track 2 will focus on long-term gas policy and planning. The preliminary scoping memo for Track 2 identifies the goals of long-term planning for the state's gas system as ensuring that utilities maintain safe and reliable gas systems at just and reasonable rates under the state's climate policies (CPUC 2020a).

This white paper contains a preliminary discussion of issues related to gas system planning that may be relevant to Track 2 of the long-term gas planning OIR. Here, the goal is to synthesize the status of discussions about long-term planning for California's gas system, scope out key considerations and questions for stakeholders and regulators, and support the ongoing consideration of strategies for long-term gas planning in the state.

Other efforts have begun to explore options for long-term gas planning in light of climate goals. In particular, the State of New York also recently initiated a long-term gas planning effort (NYDPS 2021). The State of Colorado recently passed legislation aimed at reducing building emissions from gas heating by requiring gas distribution utilities to develop and implement clean heat plans (Colorado General Assembly 2021). Researchers and other interested parties, defined here broadly as anyone with an interest in long-term gas planning, have put forth considerations and recommendations for decarbonization efforts related to gas. This paper surveys these contributions and summarizes potential strategies proposed for long-term gas planning that could be applied to the California context.

This document is composed of sections that cover three categories of considerations for long-term gas planning (Table 1). Section I focuses on technical considerations for existing gas infrastructure in the state and forecasting needs for balancing future gas supply and demand. Section II reviews economic considerations related to overall gas system economics and customer rates. Section III reviews other considerations, including continued GHG emissions and overall planning processes. Potential paths forward are offered in Section I, while Sections II and III focus on synthesizing existing stakeholder proposals for specific issues related to the gas system. In all sections, the goal of this white paper is to identify key options, considerations, and questions for regulators and stakeholders going forward.

Table 1. Categories of technical, economic, and other considerations related to Phase 2 of the Long-Term Gas Planning Rulemaking.

I. Technical considerations	II. Economic considerations	III. Other considerations
A. System condition and needs for reliable operations B. Balancing gas supply and demand in real-time and planning for the long-term C. How to "prune" the gas system?	A. Strategy for continued system investments and operations and maintenance (O&M), including those related to safety B. Stranded assets and cost allocation among customers C. How to "prune" the gas system in the most cost-effective way?	A. Continued GHG emissions B. Alignment of planning processes to broad objectives

I. Technical considerations for the safe and reliable operation of the gas system

California's gas system supplies gas to residential, commercial, industrial, and electric generation customers. Gas supply comes predominantly from out-of-state via transmission pipelines, which carry gas to customers, storage fields, and between the two (Appendix A).

The California Public Utilities Commission has regulatory authority over the transportation, storage, metering, procurement for core customers, and billing of gas in the state (CPUC 2021a).[1] The infrastructure for these activities includes transmission pipelines, which bring gas in from out of state or move it long distances; distribution pipelines, which move gas from the transmission system to most end use customers; compressor stations, which move gas along within pipelines; regulator stations, which enable pressure reductions for smaller pipelines; valves, which enable the closure of a given pipeline for maintenance, safety, or disuse; gathering lines, which take gas from the wellhead to transmission lines; and storage facilities which hold gas for later use.

[1] For a history of CPUC decisions related to the natural gas system, see St. Marie & Zafar 2015.

The state's gas transmission infrastructure is primarily operated by investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E) in the north and Southern California Gas Company (SoCalGas) in the south. Other gas utilities—including San Diego Gas and Electric (SDG&E), Southwest Gas, and publicly-owned utilities the CPUC does not regulate—rely on that transmission infrastructure to serve their own distribution customers. SoCalGas procures gas supplies for SDG&E core customers who take utility procurement, but other wholesale customers conduct their own procurement of gas supplies. PG&E and SoCalGas also serve their own distribution customers (Table 2).

Interstate transmission pipelines bring in more than 90 percent of the gas consumed in California, while the remainder is extracted in-state via gas production wells. Gas from production sites is processed and compressed prior to its introduction into either the pipeline system or storage reservoirs (used to meet fluctuating daily and seasonal demand), and additional compressor stations sited along pipelines are designed to keep gas flowing (AGA 2015, EIA 2020a). California has 12 underground gas storage facilities (Table 3).

Different types of customers benefit from different parts of the gas system. The majority of gas utilities' customers are considered core customers. These are primarily residential and small commercial customers who receive gas from the utility's distribution system and use gas largely for heating and cooking. Transmission pipelines bring gas to citygate stations that prepare it for delivery to core customers by adding odorants, reducing the pressure, and measuring gas volumes (AGA 2015). Then, distribution pipelines carry that gas to neighborhoods. Small-diameter service lines branch off from distribution mains to bring gas to individual customers (AGA 2015).

Noncore customers—including larger commercial, industrial, and electric generation customers—may use the distribution system or receive their gas directly from the transmission system. Although far fewer in number than core customers, noncore customers consume 65 percent of the gas delivered by California's utilities (CPUC 2021a). Noncore customers burn gas to drive industrial processes as well as for larger-scale heating. These customers purchase larger gas volumes and pay lower overall rates than core customers per unit of gas consumed. These lower rates are due in part to lower reliance on the distribution system (*i.e.*, their rates are designed to recover costs only for infrastructure that they use, not also distribution system costs, see Section II) as well as lower reliability standards (*i.e.*, in the case of insufficient gas supplies, noncore customer service is curtailed first), and economies of scale because larger customers consume more gas in proportion to the cost of the facilities to serve them.

Within the PG&E and SoCalGas service territories, approximately one-quarter to one-third of each utility's gas throughput serves their own core customers, less than 20 percent is sold on the wholesale market (including internationally) or to other gas utilities (much of that is then delivered to core customers), and the remaining amount serves noncore customers (Figure 1). (Seasonal variations in gas usage by customer class are discussed further in Section I.B.)

Only about 80-85 percent of the gas volumes consumed in California are delivered over utility pipeline systems. The remainder is delivered to high-volume customers, such as electric generators and industrial facilities, via interstate pipelines or directly from California producers. The CPUC does not have regulatory authority over those pipelines or deliveries. The CPUC also does not have regulatory authority over the production of gas (CPUC 2021a).

The reliable operation of California's gas system depends on being able to meet customer demand for gas in real time and into the future. Key questions that should be considered are therefore: how much gas customers will demand; when, both seasonally and hourly, will they need it; where the demand will be located; where will the gas supply come from; and how will it get to where it is needed.

Table 2. Overview of regulated gas pipeline infrastructure in California*

Gas utility	Transmission pipelines** (mi)	Distribution pipelines** (mi)		Customer meters*** (millions)
		Mains	Services	
PG&E	6,504	43,509	33,946	4.5
SoCalGas	3,341	51,424	50,546	5.9
SDG&E	218	8,236	7,074	0.88
Southwest Gas	0.1	3,202	2,534	0.2

*This table is meant to provide a sense of scale of utility gas pipeline infrastructure, not to be fully comprehensive. Other regulated gas infrastructure exists, including gas storage facilities.
**Pipeline data from PHMSA 2020.
***Customer meter data from CPUC 2020b (PG&E), CPUC 2019a (SoCalGas and SDG&E), and CPUC 2021b (Southwest Gas). Southwest Gas serves customers in three separate territories in Southern California, Northern California, and South Lake Tahoe.

Table 3. Overview of gas storage fields in California

Operator	Storage Field
PG&E	Gill Ranch,* Los Medanos, McDonald Island, Pleasant Creek***
SoCalGas	Aliso Canyon, Honor Rancho, La Goleta, Playa Del Rey****
Independent operators**	Gill Ranch,* Kirby Hills, Lodi, Princeton, Wild Goose

*Gill Ranch is owned partially by PG&E (25%) and partially by an independent operator (75%) (Long *et.al.* 2018, CPUC 2021a).
**See CalGEM 2019 for more information.
*** Pleasant Creek is slated to be sold or closed. Decommissioning is expected to begin in January 2022 if the facility has not been sold by that date.
****SoCalGas fields previously included Montebello, which was closed in 2003.

Figure 1. Recorded average daily gas sendout by PG&E and SoCalGas from 2015 to 2019 (data from: California Gas and Electric Utilities 2020, tables 24 and 32).

A. System condition and need for reliable operations

Gas utilities have been providing gas service to customers in California since the early 20th century (SoCalGas 2021, PG&E 2021a). Today's gas infrastructure encompasses thousands of miles of pipelines and a dozen gas storage fields (Table 2, Table 3, Appendix A).

Utilities make a variety of decisions and take actions to maintain and operate the system with the stated goals of preserving safety, reliability, cost-effectiveness, and compliance with local, state, and federal requirements. These activities include: preventative inspection and maintenance, corrective and supportive maintenance, pipe replacement and repair, leakage surveys and repairs, corrosion control measures, valve maintenance, meter accuracy monitoring, and tracking and marking pipe locations to avoid damage from digging (CPUC 2020b, CPUC 2019a). These activities contribute to infrastructure readiness—defined here as the ability of gas infrastructure to perform reliably, safely, and predictably to serve demand when needed. To perform these activities, regulated utilities request funding through the CPUC on behalf of ratepayers who rely on the gas system.

For decades, the CPUC's mandate has been to ensure that gas utilities provide safe and reliable service at just and reasonable rates. Current processes for approving funding authority for infrastructure investments were designed under this mandate to balance safety, reliability, and cost-effectiveness goals. Recently, these processes were modified to better prioritize safety investments. Now, the CPUC's mission has expanded to include meeting—and supporting efforts to meet—California's climate goals. The task of how to incorporate climate goals into the decision-making processes related to gas infrastructure has prompted a re-thinking of existing processes to understand how they might balance between these objectives, and how they might need to be modified for today's world. The CPUC's long-term gas planning OIR (CPUC 2020a) is intended to provide a forum for this work.

Most investments for gas infrastructure maintenance and operations are currently proposed and decided through the CPUC's general rate case (GRC) proceedings.[2] GRC proceedings are designed to review each utility applicant's particular vision for its activities and determine an appropriate total revenue requirement by balancing safety, reliability, and cost-effectiveness goals in near- and long-term system planning. Considering many specific activities within the same process enables prioritizing investments to meet stated goals. In concert with the GRC, utilities evaluate the condition of specific infrastructure assets through integrity assessments for gas transmission, distribution, and storage as regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA 2021). System risks are broadly assessed via the CPUC's Risk Assessment Mitigation Phase (RAMP) and Safety Model Assessment Proceeding (S-MAP) filings, with a focus on quantifiable safety threats (CPUC 2021c). Beyond the GRC, gas infrastructure investment decisions have typically occurred only following high-visibility accidents or service disruptions such as the San Bruno pipeline disaster and Aliso Canyon gas storage leak (CPUC 2020a) or for specific large and/or complicated infrastructure projects (*e.g.*, CPUC 2016).

However, there are currently no clear guidelines for aligning these investments with California's long-term climate goals. This limits the current GRC process' usefulness for system-level planning for a declining throughput future. For example, safety-related investments are often made on an as-needed basis without review of which projects or alternatives would best fit within the long-term vision for the system. Issues discovered via integrity assessments are corrected, but the information provided is not currently well-integrated into system-level investment or planning decisions. Little broad visibility therefore exists into the current and ongoing health of the gas infrastructure system. This lack of visibility makes it difficult for regulators and stakeholders to assess required investments for long-term gas system maintenance, and how these investments might fit with declining utilization of the gas system.

In the past, individual events have prompted re-evaluations and modifications of CPUC processes. For example, the San Bruno gas pipeline disaster prompted the addition of Pipeline Safety Enhancement Plan (PSEP) Proceedings, under which utilities are replacing some pipeline segments made of out-of-date materials. The RAMP approach was borne out of the need to create a risk-based decision-making framework, which is intended to provide a more quantitative process for balancing two of the Commission's mandates: safety and just and reasonable rates. RAMP applies a risk-based decision-making framework to safety-related activities considered within the GRC proceeding. Following the 2016 wildfire season, the CPUC, in concert with the California Legislature, required the development of wildfire preparedness plans (CPUC 2018). Recent events, including repeated gas system outages and limitations leading to price spikes, large changes to the gas and electric markets caused by renewable energy deployment and climate change, and the increased focus on decarbonization have underscored the need for updated gas system-wide

[2] PG&E's transmission pipeline and storage investments have historically been considered in the PG&E Gas Transmission and Storage (GT&S) proceeding but have been incorporated into PG&E's most recent Test Year 2023 GRC (A.21-06-021). Further discussion on rates and rate proceedings can be found in Section II.

planning. To help facilitate this and create a new long-term vision for California's gas system, the CPUC opened the long-term gas planning OIR (CPUC 2020a).

To assist in long-term gas planning, interested parties have proposed the need for a baseline assessment of the current system to evaluate existing and future needs and its interaction with changing demand due to factors such as energy efficiency and the growth of renewable generation (Gridworks 2021, Anderson *et.al.* 2021, Gridworks 2019, Bilich *et.al.* 2019). Such an assessment could enable a better understanding of the health of the gas infrastructure in California, the continued investment required to keep the system operating, and options for future scenarios of gas infrastructure operation and decommissioning.

To begin this effort, the CPUC is initiating a data request with PG&E, SoCalGas and Southwest Gas to gain greater visibility into gas system health, operations, and maintenance needs. This data request is intended to solicit gas system information to use as a baseline for making long-term planning decisions, including system investment and decommissioning. It includes information about pipeline health, testing, historical and planned investments and maintenance, customer utilization, and cost recovery. A summary of this data request can be found in Appendix B.

Key considerations and questions for regulators and stakeholders include:

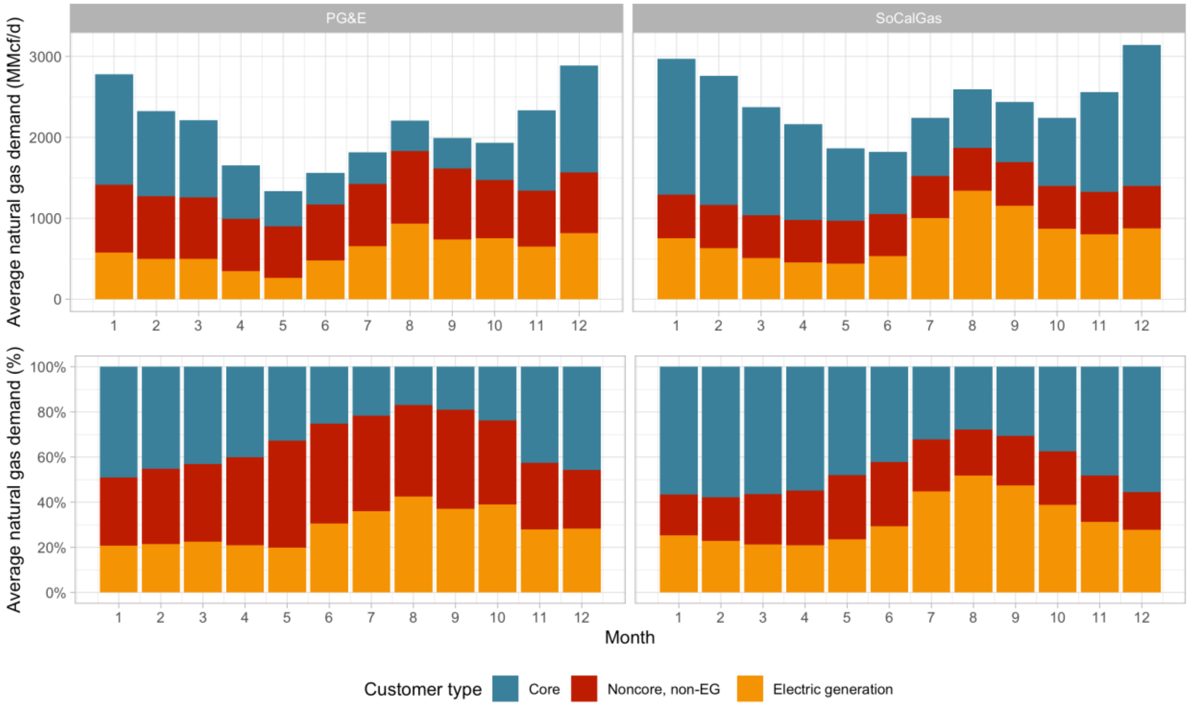
1. How can infrastructure information help guide long-term planning decisions?
2. Which infrastructure information in Appendix B is most relevant for long-term planning decisions, and how should it be prioritized for review and consideration?
3. Does Appendix B omit any key information?
4. What non-infrastructure information, such as population patterns, climate projections and/or weather forecasts, should also be a regular component of long-term planning?

B. Balancing supply and demand in real-time and planning for the long-term

Residential, commercial, industrial, and electric generation customers use gas at different times and for different end uses. Overall system demand peaks occur in the winter, driven by core residential and commercial demand for heating. Peak gas demand for electricity generation is attributable to peak summer electricity demand for cooling loads (Figure 2). Yet despite their seasonal differences, both core and electric generation customers follow similar daily demand patterns (with a morning and evening peak) due to residential use patterns and renewable resource availability. Industrial customer demand follows varying daily and seasonal patterns that depend on industry-specific characteristics.

This section discusses the primary near-term and future supply and demand balancing issues for gas system planning.

Figure 2. Average daily gas demand by month in 2020 (PG&E 2020a, SoCalGas 2020).



1. Real-time system balancing requires resiliency

Gas pipelines and storage fields supply residential, commercial, industrial, and electric generation customer demand without issue during normal system operation, which includes typical variations in supply and demand over time. However, maintaining reliability also requires the gas system to be resilient when unexpected or extreme conditions occur. While demand and supply disruptions are not new, future environmental conditions, infrastructure upkeep, and policy decisions will change how they occur and the system will need to adapt accordingly.

The CPUC requires the core acquisition departments of the gas utilities to purchase long-term, firm gas supplies, firm interstate and intrastate transportation capacity, and intrastate storage on behalf of core residential and small commercial customers. Noncore customers, including gas-fired electric generators, make their own gas purchase and transportation arrangements, frequently from marketers who purchase gas and capacity rights for resale. Numerous types of physical and financial market transactions over varying time periods are used by gas system participants and operators to match physical supply with hourly, daily, and seasonal demand and to hedge economic risks. Once purchase decisions are made, pipeline operators manage supply and demand in real time and aim to keep pipelines within safe pressure bounds. To do so, they take operational actions, such as changing regulators' set pressures, increasing compression, injecting into storage, and withdrawing from storage. These decisions control the amount of gas within the pipelines themselves, known as "linepack," and thereby the pressure within the pipelines. Operators allow linepack to vary within known ranges, essentially providing real-time storage (AGA 2015), but overly high or low linepack may lead to dangerously low- or high-pressure conditions. To avoid these, pipeline operators may also manage line pressure through Operational Flow Orders (OFOs), which impose financial penalties for customers if they use too much or too little gas relative to what they scheduled in the day-ahead market, or through not allowing additional gas onto the system during high system pressure events. However, disruptions to either demand or supply can stress system operators' ability to manage system conditions in real time.

a. Demand stresses

Stresses may occur on the system during periods of high demand. Such periods can occur on cold winter days with high heating needs, particularly in the morning and evening. They can also be caused by high gas demand from electricity generators on summer evenings or during periods of low-renewable weather conditions, such as cloudy and calm winter days or during fire season when smoke impedes solar generation (Long *et.al.* 2018).[3]

Two primary reliability standards inform system planning for PG&E and SoCalGas (Table 4).[4] Both utilities' systems are designed to enable the provision of gas services to all customers on a winter peak day but only to core customers on an extreme peak day (with the understanding that under these conditions other customers, including electric generators, would not receive gas service). Peak days are defined by weather conditions, which in turn are based on historical averages. That target amount of capacity is currently determined by each utility's estimates of how much gas customers would demand under those weather conditions as well as economic growth factors, energy efficiency programs, and enacted legislation.

If demand cannot be met, some customers would be curtailed under prescribed curtailment orders. For SoCalGas, curtailment would start with a proportion of electric generators, then other noncore customers, then the remaining electric generators, then finally core customers (SoCalGas 2016). For PG&E, customers receiving interruptible service would be curtailed first, followed by curtailments by contract price, which enables noncore customers to be curtailed before core customers (PG&E 2020b). As currently prescribed for SoCalGas, such curtailments should occur fewer than once in 10 years for any customer and fewer than once in 35 years for core customers. Yet each utility's ability to meet its reliability standards depends, in part, on correctly estimating (1) how frequently and intensely extreme weather conditions will occur in the future, and (2) how those weather conditions will translate into customer demand. Under-sizing the system may lead to higher risk of curtailing customers, while over-sizing may lead to unnecessary infrastructure investments.

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[3] California's increasing reliance on renewable electricity resources creates the potential for significant loss of electricity generation during "dunkelflaute" periods, or times when the sun and wind generate little power. Finding a carbon-free way to meet California's power needs during these "dark doldrums" is one of the challenges the state must overcome to meet its climate goals. Potential solutions include alternate generating sources, storage resources, and/or demand response.

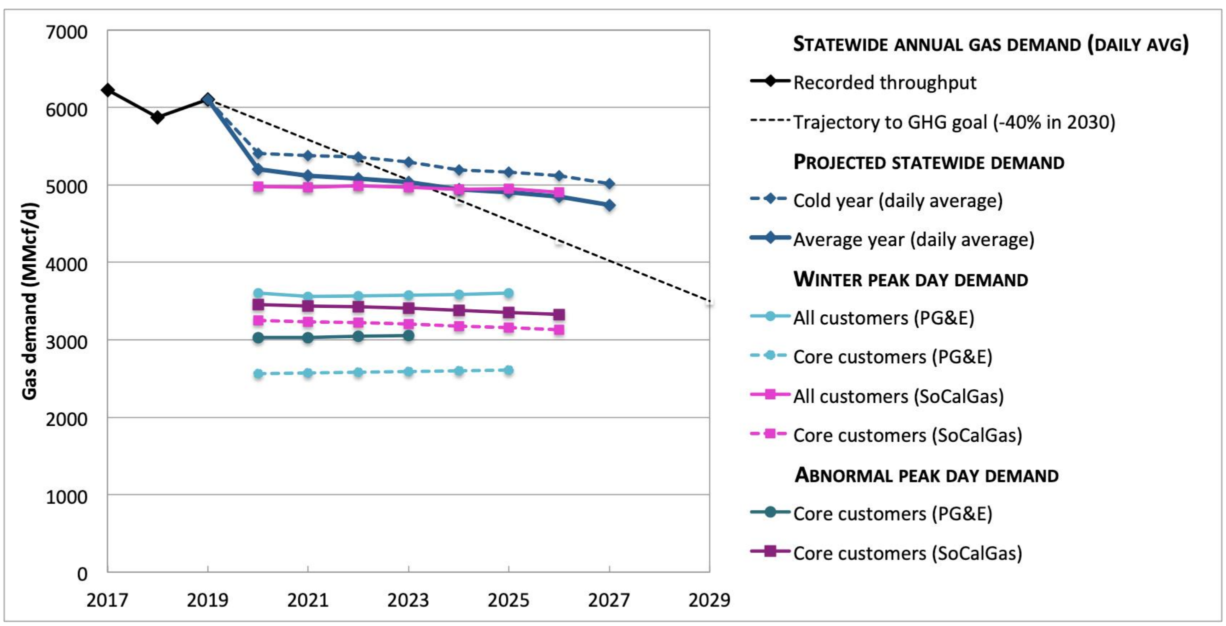
[4] These reliability standards are currently under consideration in Track 1 of the Long-Term Gas Planning Rulemaking, to which readers are referred for additional discussion (Spencer *et.al.* 2020, CPUC 2020a).

Table 4. Reliability standards currently used for gas utility system planning in California (California Gas and Electric Utilities 2020 and SoCalGas 2020).

Gas utility	Winter cold day standard*			Extreme peak day standard**		
	Specified planning standard	Estimated system composite temperature (°F)	Estimated total gas throughput in 2021*** (MMcf/d)	Specified planning standard	Estimated system average temperature (°F)	Estimated core gas throughput in 2021*** (MMcf/d)
Pacific Gas & Electric****	1-in-2		3,561	1-in-90	28.3	3,031
Southern California Gas	1-in-10	42.2 (SoCalGas)	4,967	1-in-35	40.5 (SoCalGas) 43.0 (SDG&E)	3,440

*Gas utilities plan their systems to provide service to all customers under these conditions.
**Gas utilities plan their systems to provide service only to core customers under these conditions.
***See Figure 3 for projections in additional years.
****PG&E also reports values for a 1-in-10 winter peak day in the California Gas Report, but this is not the standard used for planning. Specified planning standards for winter reliability differ for historical reasons (Reisinger 2020). Rather than an estimated system composite temperature, PG&E uses heating degree days (HDDs) to estimate gas system throughput.

Figure 3. Comparing statewide average and peak to utility-specific peak gas demand forecasts from the 2020 California Gas Report.



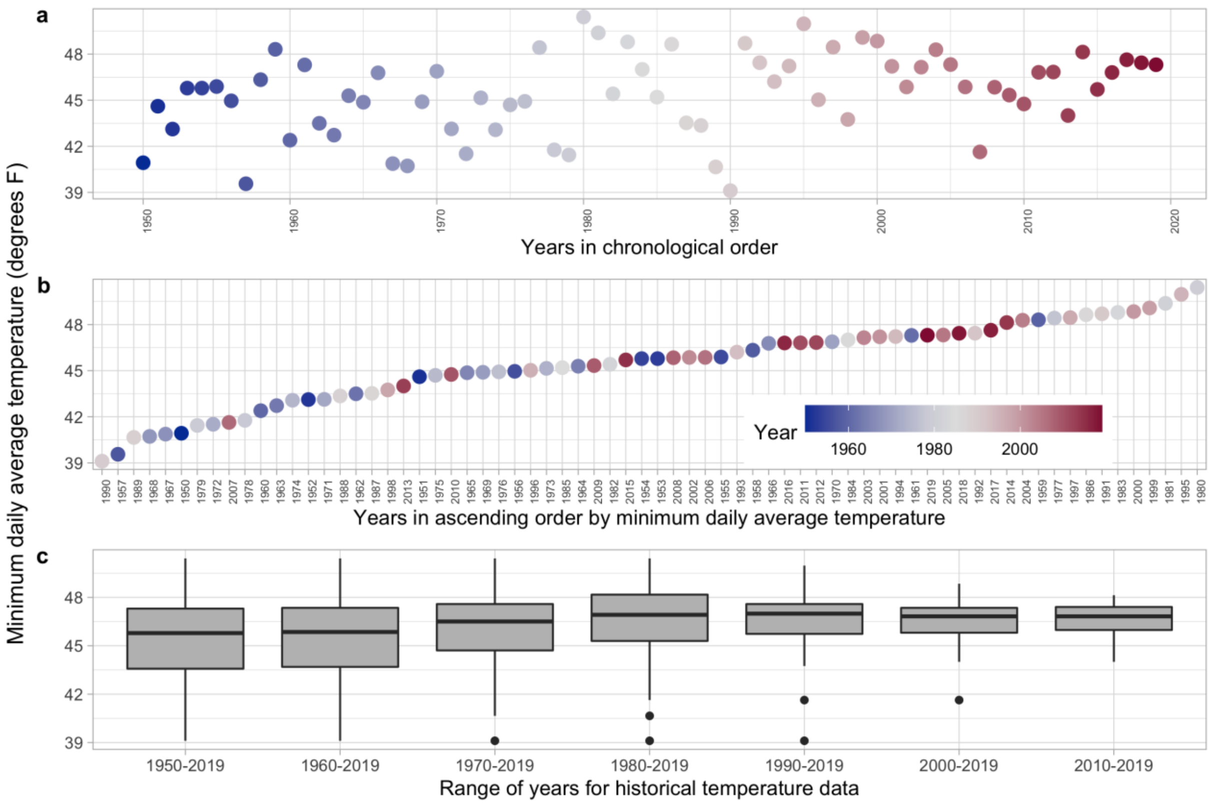
While statewide gas demand is projected to decline, on average, current projected decreases fall short of what is needed to meet California's emissions goals. Winter cold and abnormal peak day demands for each utility are projected to stay relatively steady, to the extent that winter cold demand for all customers in SoCalGas's territory may meet or even surpass statewide average demand (California Gas and Electric Utilities 2020).

The daily composite temperature and demand associated with each planning standard come from forecasts made by the utilities. Utilities currently predict which weather conditions will occur in the future by looking at historical data. For example, for the 2020 California Gas Report, SoCalGas calculated its estimated 1-in-10 and 1-in-35 peak day temperatures by calculating the 90th and 97th percentiles, respectively, of the annual minimum daily system average temperatures over the last 70 years (SoCalGas 2020, pp.316-323). SoCalGas also introduced a climate change adjustment that assumes heating degree days (HDDs)[5] will continue to decline at a rate of four per year, which is the average rate of annual warming within its service territory over the last 20 years (SoCalGas 2020, pp.314-315).

The prediction of temperature conditions representing 1-in-10 and 1-in-35 reliability standards is highly sensitive to the number of years of historical data included in the statistical analysis (Abdelaziz 2019, p.53). For example: the 90th percentile of the past 70 years of cold weather data will yield a colder planning day than if considering just the past 10 years, as the last 10 years were warmer than the previous 60 years (Figure 4). However, using a smaller range of data would also increase variability, leading to larger confidence intervals. Therefore, this white paper does not recommend just reducing the amount of data used in this prediction, but rather reconsidering what kind of data and what statistical approaches are necessary to make a best-effort representation of what future conditions are expected to be (including, potentially, types of cold weather conditions such as the Polar Vortex). Incorporating climate projections (discussed below in Sections I.B.2 and I.B.3) is key to this exercise. Choosing the appropriate analysis threshold and method for forecasting the trend is important to avoid unneeded system investment while preserving the desired system reliability.

[5] Heating degree days measure the difference between a reference temperature, typically 65 degrees Fahrenheit, and the daily average temperature for days that are colder than the reference temperature. For example, a day with an average temperature of 55 degrees F would be measured at 10 HDDs. A closely related analogue is cooling degree days (CDDs), which measure the difference between a reference temperature and the daily average temperature for days that are warmer than the reference (Franco 2018).

Figure 4. Historical temperature data used by SoCalGas in the 2020 California Gas Report for calculating peak winter day conditions.



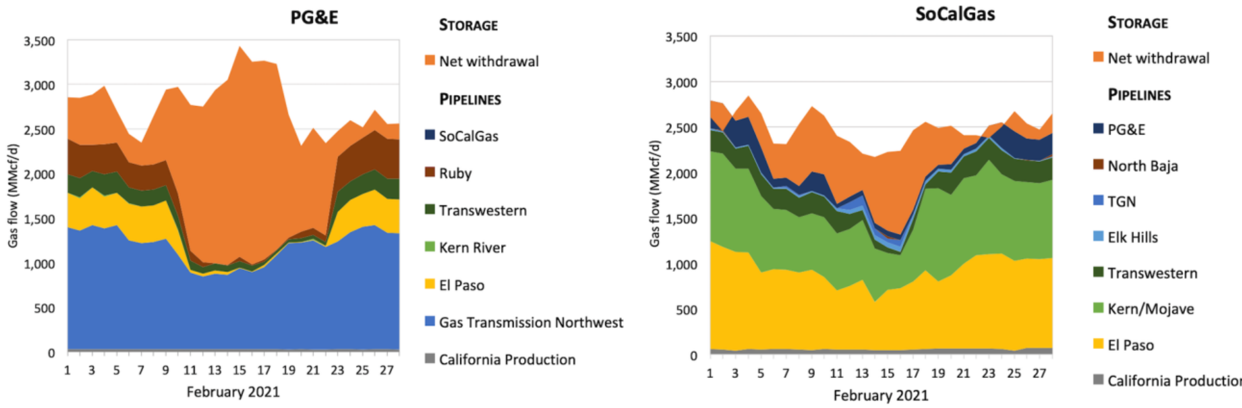
These temperature values were used to calculate system composite temperature for 1-in-10 and 1-in-35 peak days (SoCalGas 2020): (a) shows minimum daily average temperatures for years 1950-2019 in chronological order, (b) shows the same data plotted in ascending order by temperature, and (c) shows boxplots of all temperature data included by starting decade. Boxplots indicate the 25th, 50th (median), and 75th percentiles of the data by the lower, middle, and upper lines of each box, and whiskers show the furthest points within 1.5x the interquartile range. Additional points are shown as outliers. Using just more recent temperature data narrows the range of expected temperatures to warmer conditions.

b. Supply stresses

Meeting customer demand also requires access to the right amount of gas supply. Supply constraints (lower-than-expected supplies from typical sources that may drive up gas prices) or disruptions (an inability to receive the amount of gas supply to serve demand) may occur due to insufficient gas volume or inadequate infrastructure. California currently gets 85-90 percent of its gas from out-of-state, making it vulnerable to system shocks such as reduced gas imports due to extreme weather conditions in other parts of the country. A notable example of such a supply constraint occurred in February 2021 as a result of extreme winter weather conditions in Texas and the Midwest (Figure 5).

Similarly, pipeline and storage infrastructure are needed to move gas to and within service territories and deliver it to customers at the right time to meet demand. Infrastructure readiness and storage resource availability are therefore key issues to consider in gas system long-term planning.

Figure 5. Gas supply resources that met demand in PG&E and SoCalGas service territories during February 2021.



PG&E's imports from the south declined dramatically, and demand was supplied primarily by storage resources and pipelines from the north (PG&E data source: Pipe Ranger). SoCalGas has less storage capacity in its system relative to PG&E, but it still continued to rely on gas storage during this event (SoCalGas data source: Envoy). Notably, weather in California was relatively mild during this time, reducing SoCalGas's need to procure gas while supplies were constrained.

2. Planning for future changes to demand and supply should consider new conditions

Beyond resiliency to short-term stresses, the gas system will also need to adapt to changing conditions. While changes in future conditions should be assessed for their impacts on both supply and demand, the focus here is on demand impacts to enable continued discussion on how to plan for changing future use of the gas system.

a. Climate change and electrification will impact gas demand

Gas demand is highly sensitive to temperature (Abdelaziz 2019), and the distribution of hot and cold days in the future will be different than the distribution in the past. Climate projections for California are currently available via Cal-Adapt.org (CEC 2021a) and include heating degree days, cooling degree days, and local temperature predictions throughout California for a variety of climate models. The current winter peak day standards are intended to capture both an expected frequency of unusually cold weather as well as a tolerable reliability standard for gas disruptions given that cold weather. Climate projections can provide insight on the magnitude and frequency of cold days expected into the future. Climate projections beyond California—*i.e.*, for nearby regions such as the intermountain West that rely on the same gas supply sources—should also be considered to evaluate the potential for simultaneous regional demand and supply issues due to extreme weather.

California's greenhouse gas reduction goals have prompted growing attention on building electrification as a strategy to help meet state targets (Mahone *et.al.* 2018). Some local jurisdictions have already enacted building codes to limit gas connections in new construction, and researchers predict increased uptake of electric appliances relative to gas in both new and existing homes (Mai *et.al.* 2018). Electrification opportunities may exist in industrial and other sectors as well (Deason *et.al.* 2018, Stephens & Krishnamoorthy 2019).

b. *These conditions will have broad implications for the gas system*

Climate change and electrification will affect customer demand for gas in a variety of ways. Demand forecasting will need to account for the following impacts:

Reduced gas demand, on average: Residential customers and core commercial customers who primarily use gas for heating will likely use less gas on average as temperatures warm in California (Karas *et.al.* 2021). Residential electrification will also reduce gas use as new appliances are more efficient and may shift electric demand to periods more likely to be served by non-gas generation (Brockway & Delforge 2018). Reductions in gas usage will lead to lower utilization of gas infrastructure (Bilich *et.al.* 2019).

Shift in gas end uses: Where gas is still used by customers, the types of uses may shift. For example, residential customers may shift to electric heating faster than to electric cooktops, making remaining gas usage lower (and more predictable on a diurnal cycle) for utilities (Karas *et.al.* 2021). These shifts may cause the clear statistical relationships that have existed to date between temperature and gas sendout to weaken (Abdelaziz 2019), complicating the usage of 1-in-10 or 1-in-35 winter days for reliability standards.

Potential for increasing gas demands from electric generation: Electric vehicle adoption and building electrification may cause shifts in the total amounts and timing of electricity demand, which in turn may increase or decrease the demand for gas generation. Periods of low solar and wind conditions, such as during cloudy winter days and/or fire season, may prompt greater utilization of gas-fired electricity generators to serve load. Drought conditions may reduce the state's ability to rely on hydropower generation, potentially leading to greater demand for gas to serve reliability needs (see, *e.g.*, Hallahan & Micek, 2021). These trends will coincide with expected coal and nuclear plant retirements and increased reliance on renewable energy in the Western U.S., which together could increase gas demand for electric generation by 30 percent from 2018 to 2026 (Wood Mackenzie *et.al.* 2018), thereby increasing competition for the electricity production from gas-fired generators. The combination of these trends may also mean that gas demand shifts from core to noncore generation customers, with implications for rate recovery and system financing (to be discussed further in Section II).

Unclear impact on peak gas demand: Another key consideration is the relative balance between average and peak demand. While average demand for the gas system is expected to decline, the net impact on peak winter demand is less clear. Gas utilities forecast that peak demand may stay relatively steady (Figure 3, Long *et.al.* 2018), and more research is needed on climate change trends in cold months. If peak demand stays high, infrastructure will still need to be sized to meet that demand, even if declining average demands suggest some infrastructure may no longer be needed. Economic implications are discussed in Section II.

Shift in gas peak: As heating demand declines while electricity demands increase, it is possible that in the future the gas peak may shift towards the summer months (Karas *et.al.* 2021). Gas demands by electric generators would then be a greater driver of gas infrastructure utilization than core customer demand.

3. Gas system forecasting assessment and next steps

The near-term and long-term gas system trends described above prompt observations relevant to adjusting forecasting practices to ensure that California is planning for the conditions of the future, not those rooted in the past.

Current gas forecasting processes lag behind what is needed to truly represent changing conditions going forward. Specifically, today's forecasts do not sufficiently account for climate projections or the potential range and pace of electrification (Kenney *et.al.* 2021), both of which prompt consideration of how geographic and temporal uncertainty can best be integrated into gas demand forecasting. Further, current gas forecasts provide limited temporal and geographic granularity in overall system forecasts, which prevents detailed assessment of how changing weather conditions in California's climate zones may impact local demand and system conditions.

The following options for forecasting demand and supply and integrating those forecasts into the planning process are intended as starting points for conversations between regulators and stakeholders.

a. Increase transparency and substance of demand forecasting

The demand forecasting process merits revision to define true system needs. In designing new forecasting approaches, climate projections, electrification trends, and temporal and geographic granularity within utility service territories should be considered and incorporated. Utilities, regulators, and stakeholders could also evaluate how state emissions reduction targets should be accounted for in demand forecasts.

Key considerations and questions for regulators and stakeholders include:

1) How many years of historical weather data should be used to generate near-term predictions of extreme winter peaks? (See Section I.B.1.a.) What statistical approaches should be used to enable manageable confidence intervals in near-term predictions?
2) What level of spatial granularity is needed in local demand forecasts to assess the potential to retire certain gas infrastructure (see Section I.C for a discussion of infrastructure retirement) and/or implement non-pipeline alternatives to serve demand?
3) How should climate projections be incorporated into long-term gas system demand forecasts, acknowledging that uncertainty cannot be mitigated entirely? (See Section I.B.2.) See Box 1 for a potential approach.
    a. How should evaluations of future climate conditions assess the possibility of simultaneous extreme events in California and nearby regions (e.g., Texas, Oregon, Washington, and the rest of the Western U.S.) in either the winter or summer, given potential future weather patterns and California's reliance on gas and electricity imports?
4) What electrification assumptions should be used, and how should they be incorporated into gas demand forecasting?

a. Heating electrification may reduce the correlation between gas demand and peak winter days; how should this be tracked, and when should alternative approaches to reliability standards be considered? (See Sections I.B.1.a, I.B.2.)
b. Gas demand may shift from core to noncore electric generator customers. How should this trend be tracked in forecasts? (See Section I.B.2.) What level of granularity of customer types should be reflected in forecasts?
c. Given the state's vehicle electrification policies, what assumptions should be used to forecast refinery and upstream oil and gas production demand, including for refineries' hydrogen production?
d. Battery storage may mitigate some of the effects that electric generators' rapid ramping would otherwise create on the gas system. How should the potential for battery storage to serve this purpose be projected and tracked?

Additionally, it may be instructive to separate gas demand forecasting into bottom-up demand forecasts and scenario forecasts that project what is needed to meet the state's climate goals (Hopkins *et.al.* 2020, CEC 2021b). Under this approach, demand forecasts would incorporate existing policies and programs (e.g., local bans on gas in buildings, efficiency trends) to ensure the gas system meets reliability standards given expected customer demand. Embedded climate and market assumptions that currently rely on historical data should be weighted towards more recent trends. Separately, scenario forecasts would consider what it would take to align gas demand with the state's greenhouse gas emissions targets and climate goals. The gap between demand and scenario forecasts can then be instructive for policy- and decision-makers to assess where additional policies, programs, and market actions are needed to align current forecasted demand with the trajectory needed to meet climate goals (a similar approach is described in CEC 2021b).

b. *Increase transparency and reach of supply forecasting*

Supply forecasting processes, while not the focus of the present document, also deserve attention. In the near term, increased transparency of existing utility supply forecasting processes (*i.e.*, the supply forecasts in the California Gas Report) and their key assumptions would be helpful to enable stakeholders and regulators to evaluate long-term supply needs (Karas *et.al.* 2021). In parallel, the development of supply forecasting processes should be considered for fossil gas alternatives (e.g., biomethane, green hydrogen, synthetic natural gas, and carbon capture) (Gridworks 2021).

c. *Coordinate with the CEC IEPR forecasting process*

The California Energy Commission (CEC) releases its own gas forecast as part of its biannual Integrated Energy Policy Report (IEPR) (CEC 2019, CEC 2021b). While the electric demand forecasts published through the IEPR process feed directly into a wide variety of state planning processes, the gas forecasts relied on for planning currently come from the utility-published California Gas Report. It will take a substantial amount of work to modify and update the gas forecasting processes, as described above, and ideally this would occur in coordination with CEC researchers (Gridworks 2021). The CEC undertook a number of workshops through summer and fall 2021 that addressed gas demand forecasting in the IEPR. Additional discussion about gas demand forecasting can occur in the Long-Term Gas Planning OIR proceeding as well as in continuing CEC forums.

Box 1. A possible approach to incorporating climate projections into energy demand planning, adapted from Brockway & Dunn (2020).

i. Select climate models and emissions scenarios.*

ii. Identify geographic region(s) of interest and upload to Cal-Adapt. Identify appropriate climate variables and temporal aggregation (e.g., average daily temperature, annual heating degree days) and download the climate projections for the region(s) of interest.

iii. Run existing demand forecasting models with the downloaded climate projections for all relevant climate models and emissions scenarios (e.g., eight times if using four climate models and two scenarios) and determine range of outcomes across all projections. Each projection will produce a point estimate in time, and the range of outcomes can be considered as the range of plausible futures. Plot range of outcomes in box-and-whisker plots for each relevant time horizon (e.g., year).

iv. Decide which percentile threshold (e.g., 10^{th}, 50^{th}, 90^{th}) of the demand forecast outputs should be used for planning decisions. Effectively, this amounts to determining a level of acceptable risk in terms of how much demand to plan for given how much demand may exist within the range of plausible futures.

v. Assess existing demand forecasting models to identify embedded assumptions that may be weather dependent; propose modifications to existing models, and iteratively rerun demand forecasts.

* Climate models incorporate varying assumptions about how atmospheric processes could evolve in response to existing and continued greenhouse gas emissions and therefore represent different plausible futures. Since we don't know which future is correct, a single climate model should not be used to make predictions. Instead, a set of climate models should be used to represent a range of plausible outcomes. In California, 10 models were selected as "priority models" for water resource planning in 2015 because they accurately characterized regional precipitation trends. Of these, four models covering a similar range of temperature and precipitation outcomes were selected to support the Fourth Climate Assessment and were recommended by the CEC in 2017 to use for energy sector planning. Emissions scenarios describe how greenhouse gas emissions might evolve in response to continued fossil fuel use and climate policy and form an important input into climate models. Emissions scenarios that have been used in California for planning include representative concentration pathways (RCP) 4.5 and 8.5 (Brockway & Dunn 2020).

C. How to prune the gas system?

The key issue in long-term gas planning for California is how to transition away from fossil gas to reduce GHG emissions while still providing safe, reliable, and affordable gas service for remaining customers until alternatives are in place. The issues discussed in Sections I.A and I.B are intended to provide sufficient technical insight on system health, operation, and demand to initiate consideration of strategies towards this goal. However, some potential options for paths forward can be evaluated.

1. Transmission versus distribution?

Transmission pipelines carry gas long distances at high pressures, while distribution pipelines deliver gas to most end-use customers. Researchers and other interested parties have focused on the distribution system as a likely initial target for gas system transition and decommissioning (Payne 2020, Velez 2021, Gridworks 2019). Indeed, a focus on distribution means that relatively fewer customers would be impacted per infrastructure segment, and reliability impacts would be localized rather than affecting the system as a whole. Moreover, since distribution makes up the vast majority of pipeline miles (Table 2), removing some of those pipelines from service represents a significant opportunity for cutting costs.

However, insights about transmission system topology, connectivity, and pipeline utilization may inform where de-rating[6] or decommissioning efforts could eventually occur on the transmission system (Aas *et.al.* 2020, Velez 2021, Gridworks 2019). It will be critical to establish criteria for when core and noncore customer demand has declined sufficiently that portions of the transmission system can be de-rated or dismantled. Modeling studies that evaluate pipeline operations under demand reduction scenarios should be run to identify potential de-rating or decommissioning opportunities as demand declines.

Key considerations and questions for regulators and stakeholders include:

1. What criteria should be used to determine when declining demand can enable transmission lines to be taken out of service and/or de-rated to distribution lines?
2. System redundancies may boost reliability and resiliency, including enabling continued gas service during maintenance. However, maintaining redundant lines also requires higher continued investments in the gas system. How should the tradeoffs of maintaining potential redundancies be evaluated in the context of system de-rating/decommissioning?
3. Should portions of the gas system under consideration for decommissioning or downrating continue to be held to the same reliability standards as the rest of the system?

2. Pruning the gas distribution system

In considering options for gas system transition, Payne (2020) outlines an approach to evaluate potential paths forward. Four potential regulatory paths towards transitioning away from the gas distribution system are proposed, and their advantages and disadvantages (summarized from Payne 2020, unless otherwise indicated) are discussed. These paths are summarized in Table 5.

[6] De-rating means operating a line at a lower pressure that enables it to be reclassified as a distribution line (PG&E 2019). This reclassification may reduce costly operations and maintenance requirements associated with a particular line. However, there currently isn't a clear regulatory path for de-rating a pipeline from transmission to distribution. See Ordering Paragraphs 4, 5, and 6 of D.18-06-028: [217013446.pdf (ca.gov)](217013446.pdf (ca.gov)).

Table 5. Options for transitioning away from the gas distribution system (Payne 2020).

Approach	Advantages	Disadvantages
All at once: Fully maintain the system until a specified target date, then decommission the full system	1. Avoids bias in selecting which locations to target first 2. Administratively simple and easiest to communicate	1. Requires costly continued investment 2. Incentive for continued gas use 3. Potentially greatest impact on residential customers who do not transition in time; high costs to transition all at once 4. Maintaining energy reliability during a wholesale transition would pose considerable logistical challenges*
Geographic priority: Prioritize system sections for decommissioning according to selected criteria	1. Most economical if criteria for decommissioning are based on avoiding new capital investment 2. Fewer large-scale impacts on customers who do not transition in time 3. Existing analogs (e.g., abandonment proceedings where utilities request to be released from their duty to serve customers within an uneconomic part of their system) may provide an initial framework to implement this approach	1. Requires difficult decisions about prioritizing system sections for decommissioning that will impact infrastructure and customers, which may entail tradeoffs between minimizing total costs and helping those customers with the greatest need* 2. Upfront transition costs required for customers*
Usage type priority: Prioritize transition for gas uses that are easiest to electrify	1. Economic substitutions for easy-to-electrify uses are available; can invoke market and/or permitting rules to prevent sales or installation after a certain date 2. Rising rates due to reduced gas sales will incentivize consumer switching to available non-gas alternatives for non-prioritized uses and drive technological innovation for other appliances, assuming rates for non-gas alternatives are lower 3. Potential to avoid captive ratepayers if customers can switch to cheaper alternatives when costs grow too high; analogs exist: e.g., landlines to cellphones	1. Potential for enforcement challenges 2. Requires proactive coordination with customer-facing professionals (e.g., HVAC installers) 3. Upfront transition costs required for customers 4. Landlord/tenant split incentive could pass greater costs to renters 5. Remaining dispersed gas demand may make it harder to decommission lines* 6. High gas rates may impact most vulnerable customers*
Restrictions based on source: Invest in renewable gas or hydrogen options	1. Enables continued use of some sections of the gas system, potentially reducing stranded asset risk* 2. May provide options for hard-to-electrify industrial customers* 3. May provide reliability benefits for critical customers, e.g., hospitals, during events such as public safety power shutoffs*	1. Scalability may be limited 2. Expensive 3. Retains potential for methane leaks 4. Existing pipelines may require upgrades to be used for hydrogen

*Not mentioned explicitly in Payne 2020 but proposed here as additional potential implications.

In the context of the gas transition in California, it may be instructive to consider each of these options as discrete paths that could be combined into a multi-prong strategy. Each option is discussed below.

All at once: To our knowledge, this approach has not yet been proposed by interested parties for consideration in California. The costs of fully maintaining the gas system prior to the target date, potential shortages of equipment and installation and permitting labor, and the difficulty of electrifying some gas customers (e.g., industries that require high heat processes) likely make this option undesirable as described. However, elements of this approach could be considered. Specifically, regulators may want to consider setting a target sunset date for portions of the gas system, which would follow implementation of gas alternatives. This sunset date would act as a marker in time for the gas system transition and provide a clear goal for stakeholders to work towards. Moreover, the sunset date could be staggered across the state to alleviate logistical shortages and make progress while accounting for hard-to-electrify customers. One challenge to using sunset dates is current uncertainty about the speed and magnitude of potential developments such as electrification, legislative changes to the obligation to serve, breakthroughs in long-duration storage, and the availability of renewable gas and/or green hydrogen.

Geographic priority: This approach, referred to as "piecemeal" in Payne 2020, requires detailed infrastructure assessments to evaluate the health and usage of the gas system and prioritize sections for decommissioning. While a challenging technical undertaking, this approach carries the potential to identify opportunities for infrastructure retirement that will avoid significant system investment while impacting relatively few ratepayers in the near term (Aas *et.al.* 2020, Lamm & Elkind 2021). This exercise will necessitate a more thorough understanding of the gas system than is available today, and the data request described in Section I.A is intended to initiate this process. Such an analysis will also be supported by a parallel effort at the CEC (CEC 2020). Moreover, interested parties have expressed support for related paths forward (e.g., targeted electrification in areas with assets that are fully depreciated or in need of significant maintenance is proposed by Velez 2021, Gridworks 2019, and Hopkins *et.al.* 2020 and will be discussed further in Section II).

Usage type priority: Pursuing this approach, referred to as "restrictions based on use" in Payne 2020, would require a detailed assessment of gas uses and their available alternatives as well as decisions about which uses to prioritize for electrification. Interested parties have demonstrated support for elements of this path through proposals to evaluate residential gas end uses and consider applying different rate structures to these uses (Table 6, to be discussed further in Section II). Of these, baseline and preferential uses have the most market-ready alternatives to gas technologies and could be prioritized for electrification. Some policies already differentiate by end use: some jurisdictions that have passed or are considering gas bans have included exemptions for preferential or luxury uses (Gough 2021). Notably, use-based restrictions do not enable decommissioning of gas pipelines but could support a customer-oriented behavioral transition that helps move in that direction. This approach may allow more customer choice than a geographic priority approach. Moreover, building electrification has been proposed as a mechanism to allow consumers to opt out of paying rising gas system costs by reducing their reliance on the gas system (Aas *et.al.* 2020).

Table 6. A possible categorization of residential gas uses (adapted from Velez 2021, Gridworks 2019).

Gas use	Examples	Alternatives to gas
Baseline	Space heating, water heating	Electric heat pump space and water heaters
Preferential	Cooking	Electric or induction cooktops, electric ovens
Luxury	Gas fireplaces, pools, saunas, etc., and infrequent gas use in vacation homes	

Restrictions based on source: Alternative gas options, including biomethane, renewable gas, and green hydrogen, are costly and available only in small quantities. More work is needed before they could substitute for fossil gas on a large scale (Aas *et.al.* 2020, Mahone *et.al.* 2018). Barring significant development of supplies, restricting fossil gas use in favor of alternative gas options may in practice amount to a proposition similar to near-total decommissioning of gas uses (Anderson *et.al.* 2021), except with some hard-to-electrify uses ultimately relying on gas-like alternatives.

Importantly, no matter which option or combination of options is selected, all paths challenge the current understanding of utilities' obligation to serve in the context of gas provision. There is no path forward to transitioning away from the fossil gas system where it will be possible for gas utilities to continue to provide fossil gas service to all customers who want it for any desired use. Moving forward with any of these options would therefore require clarification of how utilities' obligation to serve as we know it would need to change (Wallace *et.al.* 2020, Lamm & Elkind 2021).

Based on the discussion above, a potential approach to begin pruning the gas distribution system could incorporate elements from all four pathways considered. This approach relies on identifying and pursuing low-hanging options for transitioning away from the gas system in parallel with technological development of alternative gases for select end uses, followed by a target sunset clause that establishes a timeline for the transition, subject to electrification rates and other developments. An example of such an approach is provided here to prompt discussion among stakeholders and regulators (Figure 6):

1. Evaluate the health of the current gas system, with particular attention paid to infrastructure safety, reliability, and required investment to keep infrastructure in operation (Anderson *et.al.* 2021). Devise an approach or metric to prioritize pipeline sections for decommissioning, beginning with the distribution system, that incorporates an assessment of the health of the system and the impact on customers. The goal is to prevent avoidable investment in the system, while decommissioning infrastructure that may pose safety risks and providing case studies for future decommissioning. Further, create clear criteria for determining when it may be acceptable to de-rate or decommission transmission pipelines as well as a clear regulatory process for de-rating.
2. In parallel, establish programs and incentive mechanisms to prioritize a transition away from relatively easy-to-electrify baseline and preferential gas end uses for residential and small commercial customers, with particular attention paid to vulnerable and middle class communities, including renters. These could incorporate assistance with any electrical upgrades needed to enable new appliances. The goal would be to steer continuing residential payments for gas services to users who may choose to keep gas appliances even as rates increase, rather than those who would be forced to pay high rates for baseline heating

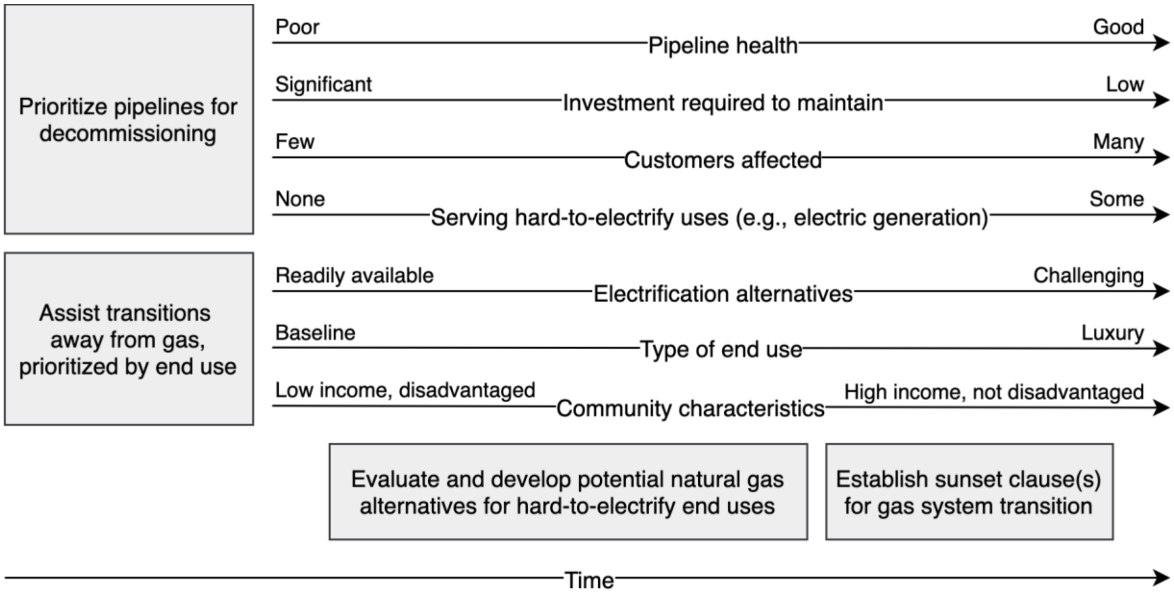
because they cannot afford to replace gas appliances. Increasing market costs may then further drive adoption of gas alternatives.

3. In parallel, continue to evaluate and develop the potential for gas alternatives, such as biomethane and green hydrogen, for supplying hard-to-electrify end uses, including industrial uses.
4. Finally, establish sunset clauses that specify a timeline for when staggered decommissioning will occur on the gas system, with potential exceptions and/or extensions for any fossil gas alternatives developed in (3) and/or infrastructure serving electric generation or hard-to-electrify end uses.

Key considerations and questions for regulators and stakeholders include:

1. How should pipelines or sections of the gas system be prioritized for decommissioning?
2. How much money can be saved by concentrating incentives geographically so that whole sections of pipeline can be removed and no longer need to be maintained?
3. Can targeting assistance to some gas uses for electrification assistance alleviate stresses on disadvantaged, tribal, and middle-income communities associated with the transition away from gas? How should the targeted uses and communities be defined?
4. What additional measures will be needed in areas affected by wildfire-related public safety power shutoff events for successful, safe residential electrification?
5. What electric infrastructure will need to be built, and where, to assume the increased load from electrification?
6. When can widespread core customer electrification be expected to materialize, and how does increased electrification depend on additional policy interventions?
7. How are the gas needs of electric generators expected to evolve? What kind of infrastructure is needed to fulfill those needs?
8. What kind of research and technological development is needed to evaluate the potential for alternative gases to supply hard-to-electrify end uses (Stephens & Krishnamoorthy 2019) and identify the most appropriate uses?
9. How should intermediate targets be set for the gas system transition? Should a system sunset clause be staggered, with different pipelines (e.g., by geographic location) having different sunset dates?
10. How can the obligation to serve be adjusted to enable these paths forward?

Figure 6. A potential schematic for the gas system transition in California.



II. Economic considerations for utilities and customer costs

Investments in California's regulated gas system are paid for through rates, including fixed and minimum costs, that are authorized by the CPUC in formal proceedings. These rates are intended to spread the costs of building, operating, and maintaining capital-intensive infrastructure over time and customers served in order to keep costs stable and reasonable for the customers who rely on the gas system. These costs include operation and maintenance expenses, administrative and general expenses, depreciation expenses, taxes, and return to investors. The cost of capital investments is recovered as depreciation expenses over time, sometimes over many years. Effectively, a utility's authorized costs, including infrastructure investments, are considered to be incurred on behalf of its gas customers, who pay back those costs, plus an authorized rate of return for capital investments (Bilich *et.al.* 2019).

The CPUC sets rates by customer class to reflect the differing costs incurred by the utility to serve different customer classes, for example due to the types and amounts of assets needed to serve a customer class. (Some customers are more expensive to serve per unit of gas, for example due to costs of individual meters, customer service, and use of distribution and service lines.) Core customers pay higher gas rates because they use less gas per meter and thus see less economies of scale. Most costs are recovered through volumetric rates (*i.e.*, dollars per unit of gas consumed). Fixed or minimum monthly charges for receiving gas service also make up a portion of customers' bills, depending on the utility and type of customer, enabling the utility to recover some fixed costs from customers who use little or no gas in a month.

Core and noncore customers are billed using different rate structures (Myers 2018). Core customer rates typically include a procurement rate, transportation rates, and a gas public purpose program (PPP) surcharge. Core customers do not buy gas at a wholesale level. Rather, they buy gas either from the distribution utility which serves their area (the default) or a Core Transport Agent of their choosing, who procures gas on their behalf. (CTAs are CPUC-licensed commercial entities, but the CPUC does not regulate the rates charged by CTAs.) Core customers also pay utility transportation rates, which may include a monthly fixed or minimum charge (*e.g.*, for residential customers) or access charges (for core small commercial customers), as well as volumetric rates. All core customers also pay a gas PPP surcharge.

Noncore customers do not take utility procurement service, and instead procure their own gas, often electing to pay other service providers (*e.g.*, gas marketers) to manage aspects of their gas service. Noncore customers pay the utility for transportation of the gas and balancing services, and potentially for optional services (*e.g.*, storage and backbone transportation). Noncore customers typically pay a monthly access charge to participate in the gas system as part of their transportation rates, and most noncore customers also pay a gas PPP surcharge (except for electric generators). These rate components are summarized in Table 7.

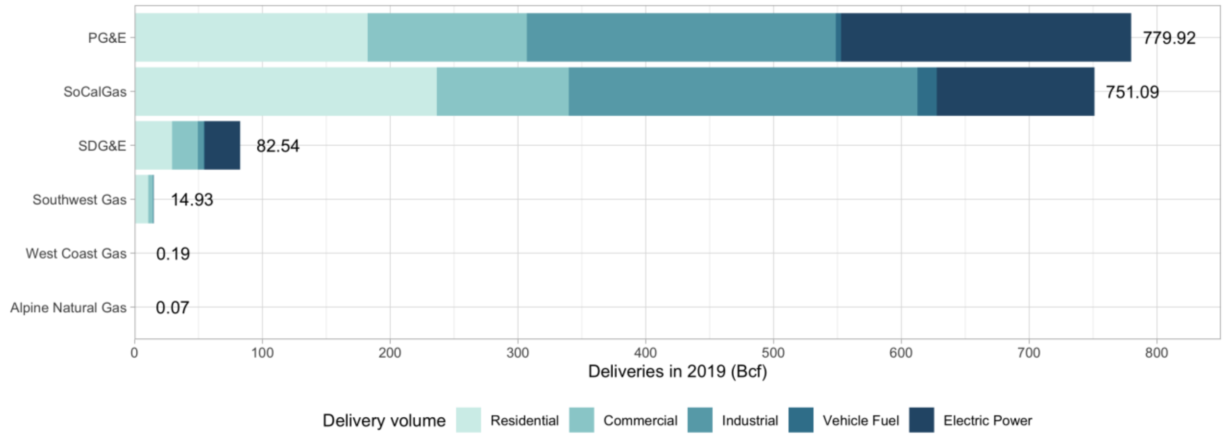
Table 7. Components of gas rates in California (Myers 2018).*

Rate component	Type of charge	Compensates for	Paid by	Paid to
Customer charge	Fixed charge per day of service or minimum charge by customer	Some customer-related system costs like service lines, regulators, meters, meter reading, and billing	Core and noncore customers	Gas utility
Procurement rate	Volumetric rate	Procurement costs, including: interstate and backbone transportation service, procurement incentives, brokerage fee	Core customers	Gas utility or CTA
			Noncore customers	Gas marketers or wholesale suppliers
Transportation rate	Volumetric rate, residential customers pay different rates for "baseline" and "above baseline" service	Costs of building, operating, and maintaining gas pipeline system, taxes, customer service, return on investment	Core and noncore customers	Gas utility
Gas Public Purpose Program (PPP) surcharge	Volumetric rate	CARE[7] subsidy, energy efficiency programs, gas R&D	Core and noncore customers, except electric generation	Gas utility

* Additional, optional rates are paid by some noncore and wholesale customers of PG&E and SoCalGas for backbone transportation service and storage service (when available).

[7] The California Alternate Rates for Energy (CARE) program provides qualifying low-income customers with a 20 percent discount on their gas bill.

Figure 7. Gas deliveries by regulated utility in California in 2019 (EIA 2020b).



The CPUC regulates rates for customers served by seven gas distribution utilities: PG&E, SoCalGas, SDG&E, Southwest Gas, West Coast Gas, Southern California Edison—Catalina Island[8], and Alpine Natural Gas Company (Figure 7). To do so, the CPUC determines the revenue requirement that is eligible for recovery for infrastructure and other services. The bulk of these revenue requirements are authorized through utility GRC proceedings. Then, a utility's authorized revenue requirement is allocated to the utility's different customer classes, based on a determination of how customer classes cause costs to be incurred in various functional categories, such as customer-related costs or distribution related costs. Finally, rates are designed for each customer class which allow the recovery of the allocated revenue requirement for each customer class. This cost allocation and rate design process is conducted in cost allocation proceedings for PG&E and SoCalGas. For smaller gas utilities, this process is conducted in the utility GRC (Myers 2018).

A key criterion for allowing cost recovery when an asset is proposed is that the asset will be "used and useful" over its expected operating lifetime (Bilich *et.al.* 2019). However, assets may cease to be "used and useful" before their costs are fully recovered, in which case they may be removed from the rate base. In practice, decisions about whether to remove an asset from the rate base have used different interpretations of this criterion. For a summary of legal and regulatory decisions (including a history of CPUC decisions) related to asset eligibility for cost recovery, see Bilich *et.al.* 2019 (pp.11-17). Any assets whose full costs are not recovered through rates during the time they are used are considered to be stranded.

The topics introduced and discussed in Section I, including the prospect of a transition away from the gas system and changing conditions for gas system operation, carry risks for utility solvency and just and reasonable customer rates. These risks include:

Higher costs per customer due to declining system demand: When gas infrastructure is used more intensively throughout the year and across customers, economies of scale result in lower rates

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[8] Catalina Island Gas Services delivers propane gas to customers through distribution pipelines (SCE 2021). However, it has been included as a party to natural gas-related proceedings at CPUC as it operates pipeline infrastructure (see, for example, CPUC 2012).

per unit of gas consumed. However, wide disparities between peak and average demand conditions may lead to pipelines being used to their full potential only rarely, with total infrastructure costs spread over fewer units of gas, therefore resulting in higher rates and higher costs for each remaining customer (Aas *et.al.* 2020, Velez 2021, Bilich *et.al.* 2019).

Higher costs for core customers who are least able to transition away from gas: As rates increase, distribution system customers will face economic incentives to electrify and reduce or stop their use of gas, assuming electricity rates are lower than gas rates. While the incentive effect is desirable, if not addressed by policy this may create financial hardship for some customers. Electrification carries significant upfront costs. These may include the costs of new appliances, upgrade costs for in-unit electrical connections and panel upgrades, and local capacity upgrades to the electric distribution system. The customers least able to access the capital required to pay some or all of these costs face the highest risk of being stuck on the gas system and bearing the brunt of higher gas rates. In the absence of targeted policy, these are likely to be the most vulnerable customers (Gridworks 2021, Karas *et.al.* 2021, Aas *et.al.* 2020, Wallace *et.al.* 2020).

Shifts in infrastructure utilization from distribution to transmission system: If core customer gas demand declines as customers electrify, portions of the gas distribution system will see less throughput. At the same time, gas demand by electric generation customers may increase during net peak demand hours. A significant quantity of gas may therefore continue to flow through transmission infrastructure to electric generators, but that flow may be increasingly volatile and irregular. If gas transmission and gas-fired electric generators are used less on average but are still needed at high capacity on short notice, new mechanisms for covering their costs may be needed.

Increased risk of stranded assets due to reduced system utilization: As the demand for gas declines some infrastructure investments may no longer be fully utilized. Assets that are not "used and useful" may cease to become eligible for recovery through rates. Asking ratepayers to pay for assets they are no longer using raises concerns about whether they are paying just and reasonable rates. However, ceasing planned cost recovery poses a challenge to the regulatory compact whereby utilities make capital investments on behalf of customers, expecting those investments to ultimately be recovered because they were considered to be prudent at the time that they were incurred. In California, the CPUC has previously adopted the "prudent manager test," whereby costs are allowed to be recovered if investments were deemed reasonable based on information available at the time, even if changes in policy directions limit infrastructure use (Bilich *et.al.* 2019). Once changing policy directions become clear, new infrastructure can be subject to a different level of justification in order to be considered prudent (see discussion of the "bright line" for new investments in Section II.A.1.b below). However, if an investment that was expected to be used and useful when it was made is later allowed to become stranded, that can complicate the regulatory compact, challenge the financial viability of utilities, lead to higher interest rates for credit given to utilities for future investments, potentially reduce utility investment in the gas system (*e.g.*, for maintenance) and put greater burdens on remaining vulnerable customers. Stranded costs can threaten principles of equitable cost allocation between current and future ratepayers, utility shareholders and ratepayers, high- and low-income customers, and gas and electric utility ratepayers (Bilich *et.al.* 2019).

Researchers and other interested parties have proposed approaches to address these issues with the goals of keeping customer rates just and reasonable, with minimal or no stranded costs. We summarize these proposed strategies in the sections below.

A. Strategy for continued system investments, operations, and maintenance, including those related to safety

Since system investment is a primary driver of increasing customer rates, options to reduce gas system investments going forward may help keep rates reasonable and avoid investing in assets that may ultimately become stranded. Opportunities for decreasing system costs relative to the current trajectory may be found both within new system investments as well as continued investment and maintenance for the current system (Gridworks 2021, Velez 2021).

1. Costs may be reduced by reconsidering system expansion

New investments in the gas system occur today in limited ways. These typically take the form of either new lines to serve new customers or increased capacity on existing lines for existing customers. Stakeholder proposals for addressing each of these types of investments are summarized as options below.

a. Option: Reevaluate programs that incentivize gas use and expansion

Interested parties have proposed reviewing, then eliminating or reducing, any existing state or utility programs that may incentivize gas use and expansion. These include current subsidies for line extensions and service connections, any programs targeting fuel switching from propane to gas, and pilots on efficient expansion of the gas distribution system (Karas *et.al.* 2021, Velez 2021, Aas *et.al.* 2020, Anderson *et.al.* 2021). As an alternative, interested parties have proposed that customers requesting gas extensions could be asked to pay the full upfront costs (Velez 2021, Hopkins 2020) and that future gas main extensions to new developments could be limited (Gridworks 2019) to avoid gas infrastructure in new construction and/or in communities that are rebuilding from wildfires (Lamm & Elkind 2021).[9]

Such proposals could prevent additional miles of pipeline from being added to the system. However, these proposals may conflict with utilities' legal requirement of the obligation to serve (see Section I.C). Interested parties have suggested that going forward, the obligation to serve should be weighed in light of socialized costs to customers, potential health impacts of indoor gas use, and policy goals, and that the social and equity imperative underlying the obligation to serve may no longer be valid with respect to gas service (Hopkins *et.al.* 2020). Interested parties further suggest working with the California legislature to address and clarify the obligation to serve (Velez 2021, Wallace *et.al.* 2020, Lamm & Elkind 2021) and suggest that a new interpretation could enable the obligation to be met with alternative fuels, including electricity (Gridworks 2019, Wallace *et.al.* 2020).

b. Option: Refine strategy for new gas investments

Beyond customer- or location-specific system extensions, situations may occur where current infrastructure is not sufficient to support future capacity needs. Notably, a modeling analysis of the

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[9] Gas line extensions are also currently under consideration in CPUC's Building Decarbonization proceeding (CPUC 2021d).

reliance on gas-fired electricity generation in the Western U.S. recommended the expansion of gas infrastructure to accommodate increased demand spurred by the retirement of coal and nuclear plants in the region (Wood Mackenzie *et.al.* 2018). Interested parties in long-term gas planning efforts propose identifying non-pipeline alternatives to conventional investments, which may include appliance energy efficiency, demand response programs, heating electrification, building envelope improvements, and compressed or liquefied natural gas (Karas *et.al.* 2021, Gridworks 2019, Hopkins *et.al.* 2020, Anderson *et.al.* 2021, NYDPS 2021). Such investments, even at the distribution level, may help offset increases in demand by electric generation.

Interested parties further propose that non-pipeline alternatives should be incorporated into long-term planning and an investment priority order should be established. An investment priority order would require utilities to demonstrate that they have adequately considered non-pipeline alternatives prior to proposing conventional assets and assessed the potential risks associated with each option (Karas *et.al.* 2021, Hopkins *et.al.* 2020, NYDPS 2021). Relevant risks may include: portfolio and societal cost-effectiveness (including indoor air quality and health impacts), carbon and methane emissions, and value of investment flexibility (*i.e.*, time value of money with modular investments,[10] coupled with annual assessments of capacity shortfalls and the status of non-pipeline alternatives). Moreover, interested parties propose that conventional gas assets should be subject to higher thresholds for justifying the need for a particular investment to avoid locking in additional gas use (Hopkins *et.al.* 2020).

Furthermore, interested parties propose that new, more stringent, criteria should be established to determine which investments are considered "prudent" and a "bright line" should be drawn in time that signifies when investments that do not meet these new criteria can no longer be included in the rate base (Velez 2021, Hopkins *et.al.* 2020, Bilich *et.al.* 2019). This approach acknowledges that previous policy directions may have enabled some investments (e.g., distribution pipelines designed to operate for decades) to be considered prudent that may not seem so today and establishes a clear signifier in time to communicate new expectations (Bilich *et.al.* 2019).

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[10] This concept has been well-documented in the electricity space: a traditional infrastructure investment sized to accommodate continued demand growth may, in theory, be more expensive than modular non-wires alternative investments (*e.g.*, via resources such as solar and storage) that can be made in stages to meet continued demand growth over time. In the traditional case, the full capital investment is made in year one and subject to current capital costs. In the alternative case, ongoing investments benefit from discount rates associated with future investments. Essentially, modular investments benefit from a lower cost of capital while preserving the flexibility to not make those investments if demand patterns change (and thereby also mitigating the risk of stranded costs). However, implementing modular investments in place of traditional projects is not straightforward (Lyons 2019, Dyson *et.al.* 2018, Menonna 2020). In the case of natural gas, such modular investments via non-pipeline alternatives could potentially substitute for pipeline-related projects in some cases when capital investments would otherwise be required. However, practical challenges exist (Narbaitz & Sloan 2019).

2. Costs may be reduced through new approaches to system operations and maintenance

Ongoing investments in today's system also carry costs. Interested parties have proposed approaches to reduce the investments that are needed to keep the current system working safely and reliably. These are summarized as options below.

a. Option: Targeted retirement of distribution system

Retiring sections of the distribution system could reduce stranded asset risk and reduce maintenance requirements (Bilich *et.al.* 2019). This strategy was previously discussed in Section I.C.2 as a potential approach to pruning the distribution system. When specifically prioritizing cost reduction, interested parties have proposed targeting electrification in areas where gas pipelines are in need of significant costly upgrades or repairs, particularly for vintage Aldyl-A piping or to address methane leaks (Velez 2021, Gridworks 2019, Hopkins *et.al.* 2020). Interested parties further propose that pilot programs should be established for targeted decommissioning, particularly in low-income communities (Velez 2021, Gridworks 2019), and that regulators and utilities should explore opportunities for synergies between gas system decommissioning and building electrification (Karas *et.al.* 2021). A significant obstacle to targeted retirement is the current interpretation of the utilities' obligation to serve.

b. Option: Refine strategies for gas system maintenance

Opportunities may exist for cost reduction in existing operational and maintenance practices on the gas system. Interested parties have proposed that regulators and utilities should work to develop pilot programs for reducing these costs, which may incorporate shorter-term repairs or non-pipeline alternatives versus complete replacement of lines in need of repair, when possible (Velez 2021, Gridworks 2019). Derating transmission to distribution pipelines (see Section I.C.1) may also reduce necessary maintenance costs (Aas *et.al.* 2020, Velez 2021, Gridworks 2019). However, there is not currently a clear regulatory pathway in California for de-rating transmission pipelines and re-classifying them as distribution. Further, regulators may evaluate options to modify California-specific pipeline maintenance and/or testing requirements (e.g., to rely more on in-line inspections).

c. Option: Revise regulatory incentives to reward performance

Finally, interested parties have proposed that regulatory incentives for utility management of gas systems should be reviewed. There may exist opportunities to modify incentives to reward more efficient and capable asset performance, such as higher levels of reliability and safety, lower costs and environmental impacts, methane leakage reduction, and peak demand reduction (Karas *et.al.* 2021, Anderson *et.al.* 2021).

B. Stranded assets and cost allocation among customers

While opportunities may exist to reduce system costs going forward, investments that have already been made will continue to drive increasing costs for remaining customers. Interested parties have proposed strategies to address the risks of stranded assets and potential cost increases for remaining customers.

1. Cost allocations could be modified to reflect changes in gas usage patterns

As gas usage patterns change, it may be prudent to evaluate current approaches to cost allocation (Anderson *et.al.* 2021). Interested parties have proposed several approaches that would shift costs to reflect new usage patterns and policy priorities. These are summarized as options below.

a. *Option: Shift costs within customer classes in time and by type of service*

Cost allocation for the recovery of authorized rates is based on the principle that the customers who rely on a particular class of infrastructure for gas service, *i.e.*, those customers on whose behalf the investment was made, should pay for the investment over time through rates. However, how those customers pay for the investments in question may be modified. Interested parties have proposed three strategies to modify rates within customer classes to capture new policy priorities. These include accelerated depreciation (*i.e.*, shifting costs in time), differentiated payment for services, and modifications to the California Alternate Rates for Energy (CARE) program that subsidizes rates for low-income ratepayers.

Accelerated depreciation refers to shortening what is considered to be the useful life of a particular infrastructure asset, *i.e.*, the life over which its costs are recovered. This approach effectively raises rates in the short term but reduces the time over which that asset affects rates. In the context of the gas system, this strategy could serve a dual purpose: applied correctly, it may prevent assets from becoming stranded once they are no longer utilized by customers and also shares the costs among a larger group of customers before some of them leave and the remainder are saddled with the remaining undepreciated costs.

Interested parties propose that accelerated depreciation could be applied to new and existing gas assets (Gridworks 2019, Aas *et.al.* 2020, Anderson *et.al.* 2021) and that depreciation schedules should be aligned with state climate targets (Karas *et.al.* 2021, Hopkins *et.al.* 2020). Further, interested parties suggest that regulators and utilities should develop depreciation schedules for assets likely to be stranded (Velez 2021, Hopkins *et.al.* 2020), as well as commit upfront to shortened decommissioning timelines for new investments (Velez 2021) and incorporate decommissioning costs into accelerated depreciation calculations (Hopkins *et.al.* 2020). This approach would provide clarity about the expected service life of infrastructure to enable informed cost and risk consideration prior to installation (Payne 2020). Interested parties also propose that non-linear depreciation schedules should be considered to front-load asset cost recovery,[11] as more customers will be using those assets in the near-term, and assets are unlikely to be equally used and useful over their full lifetimes (Velez 2021, Hopkins *et.al.* 2020). In particular, depreciation rates could be set proportionally to expected sales in a given year (Hopkins *et.al.* 2020), enabling costs to be shared when more customers are connected to the gas system (Velez 2021). Moreover, a faster return on capital for investors could be subject to less interest that must be compensated by ratepayers and frees funds for potential new investments in the gas transition (Hopkins *et.al.* 2020).

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11 A non-linear depreciation schedule for gas assets has been proposed by PG&E in its 2023 GRC application (PG&E 2021b, see Exhibit 10 Chapters 11 and 12).

Another approach to cost allocation could involve payment for specific services. Services provided by the gas system can refer to the nature of the service provided (*e.g.*, firm versus interruptible), its end use (*e.g.*, baseline or luxury uses, as discussed in Section I.C.2), or its location (*e.g.*, paying more to receive service in rural locations). Interested parties suggest that an analysis is merited of the types of services that gas provides and their allocations in rates (Karas *et.al.* 2021, Anderson *et.al.* 2021). To specifically address concerns about vulnerable customers facing high gas charges, a potential approach would be to raise the relative rates paid by high-income core customers who use gas infrequently or for "luxury" uses (*e.g.*, vacation homes, high square footage, pool heating, or fireplaces, as discussed in Section I.C.2). Relatedly, interested parties have proposed segmenting the residential gas tariff into two classes—one where gas is used for major end uses, versus one for only modest amounts as a lifestyle choice. The latter group could be subject to a higher minimum bill and fixed charge (Velez 2021, Gridworks 2019).

Another approach to directly support low-income core customers is through the CARE program, which uses funding from non-CARE ratepayers to subsidize rates for those who qualify for rate assistance. The CARE discount is currently 20 percent for gas service, but 30-35 percent for electric service (CPUC 2021e). Increasing the gas discount may help low-income customers as rates increase but could also push non-CARE ratepayers away from the gas system faster, thereby leading to overall higher rates for low-income customers as fewer customers remain on the system. An alternative approach might be to increase the electric CARE discount, to further incentivize low-income customers to transition (Velez 2021, Gridworks 2019).[12] Another approach that could help mitigate rising rates could be to fund CARE subsidies out of the state's general fund rather than from ratepayer bills.

b. Option: Shift costs between customer classes by usage and reliability needs

Rates for gas customers are designed to reflect how those customers use gas. Interested parties have proposed that a review of where costs come from in the gas system may be helpful. For example, such a review could consider how different types of system infrastructure (*e.g.*, distribution versus transmission) and different types of investments (*e.g.*, capital versus operations and maintenance costs) are now reflected in customer rates (*e.g.*, peak-day versus total usage-based cost allocations) and whether those allocations are appropriate (Anderson *et.al.* 2021). This analysis could lead to adjusting how costs are allocated between customer classes based on which types of usage contribute more to underlying gas system costs.

Modifications could involve increasing pricing granularity for sophisticated customers (Anderson *et.al.* 2021). They could also involve cost-shifting from residential and small commercial to large commercial or industrial customers if peak-day gas cost allocations are adjusted to usage-based cost

[12] Importantly, the CARE discount for electric service is set by legislative statute to be 30-35 percent (CPUC 2021f, California Legislature 2013). The CARE discount for gas service is not explicitly specified by statute or in Public Utilities Code 739.1 and may therefore be easier to modify. The CPUC does approve the *allocation* of CARE program expenses across other utility ratepayers: for example, the CPUC recently approved PG&E's proposal to continue to allocate 80 percent of CARE program expenses to electric customers and 20 percent to gas customers (CPUC 2021f). Evaluating this allocation in concert with the level of the gas CARE discount could be another way to determine appropriate relative rates for gas and electric customers.

allocations (Aas *et.al.* 2020, Velez 2021, Gridworks 2019). This latter example relies on the argument that smaller customers are charged based on peak-day usage because the gas system was designed around avoiding curtailments for core customers. As demand declines, curtailment risks will be reduced and it will become more equitable to allocate costs based on usage. However, it is not yet clear whether the magnitude of demand on peak days will continue to decline at the same rate as demand under average cold weather conditions (see Section I.B). Also, charging noncore customers who do not use the distribution system for the costs of that system could violate long-standing utility cost allocation principles.

Relatedly, shifts in gas usage from core to electric generation customers could lead to greater demand for reliable service from electric generation. Interested parties have proposed that specific electric generation facilities that are key to overall system reliability could be designated as critical and re-classified as core customers to be protected from curtailment in extreme conditions (Wood Mackenzie *et.al.* 2018). However, this could lead to higher rates for affected electric generators and make it harder for them to compete in the electricity market.

c. Option: Shift costs outside the gas system

Finally, interested parties also suggest that the rising costs of gas infrastructure maintenance may need to be shifted outside of the gas system in order to keep rates just and reasonable. Stakeholder proposals here fall largely into two categories: shifting costs to non-ratepayer revenue streams and to the electric system.

Increasing non-ratepayer revenue streams from public subsidies, cap-and-trade revenue, and the state general fund could help avoid stranded costs and keep rates reasonable for customers who continue to use the gas system (Gridworks 2021, Velez 2021, Gridworks 2019). This shift could be justified on the basis that state policy goals help create the impetus for transitioning away from the gas system. Since all Californians benefit from the achievement of these goals, the state could find it appropriate to fund them. Moreover, ratepayer funding is a particularly regressive approach to gathering funds, as low- and moderate-income customers pay a higher share of their income through rates (Borenstein *et.al.* 2021). Aside from general funding to reduce overall rates, targeted non-ratepayer funding could also help low-income customers transition to all-electric service (Gridworks 2019).

As usage of the gas system declines, usage of the electricity system will continue to increase. Interested parties suggest that shifting some gas system costs to the electric system may appropriately reflect system transition needs. For example, electric ratepayers may benefit from lower rates as electricity system costs may be spread out over a broader sales base (Velez 2021, Gridworks 2019, Payne 2020). These charges could be implemented via an exit fee mechanism, though interested parties caution that an exit fee could create a disincentive to exit the gas system and potential for gaming (e.g., in a worst-case incentive scenario, by leaving one gas appliance connected) (Karas *et.al.* 2021, Hopkins *et.al.* 2020). To mitigate this concern, an exit fee could be assessed as a transition charge on bills of electric utility customers or on the overall customer base of the electric utility to whom the customer transitions (Velez 2021, Gridworks 2019).

2. Long-term gas system planning merits development of a financing strategy

Apart from reconsidering gas system costs and the structure of cost allocations, interested parties propose that long-term gas planning presents an opportunity to develop a full strategy for financing the gas system during the transition away from it. It is a unique regulatory position to know that investments may become stranded as they are being planned (Payne 2020), and a full economic consideration of the current system and financing choices may help enable more prudent planning. Stakeholder proposals in this area fall into categories of transparency, options for cost recovery, and considering additional financial mechanisms.

a. Option: Increase financial transparency to aid planning

Interested parties propose that increased transparency about the investment value of the gas system would be helpful to enable an assessment of options for future investments and the recovery of decommissioning costs. This could include information about the type, location, and magnitude of recovered versus unrecovered assets and their projected decommissioning costs (Velez 2021, Bilich *et.al.* 2019). This information could help regulators and interested parties evaluate the need for different interventions, such as financing stranded value and identifying alternatives to future investments (Bilich *et.al.* 2019). To this end, the capital investment and percent recovery is included in the data request to utilities that is discussed in Section I.A and summarized in Appendix B.

b. Option: Analyze and consider options related to cost recovery

Interested parties support an analysis of options related to cost recovery for existing and continuing investments in the gas system and the implications of those options (Velez 2021, Hopkins *et.al.* 2020). These options include full cost recovery with profit, the recovery of capital costs with lower or no profit, and disallowing cost recovery (Payne 2020).

The default approach, full cost recovery for capital assets with profit, fully insulates investors from policy risk and transfers that risk to ratepayers (Payne 2020). Another approach, enabling cost recovery for capital investments with reduced or no profit for the utility, would be logistically simpler for new assets than for those already part of the rate base, which regulators would have to move out of the rate base. However, regulatory precedents do exist for applying this approach to existing assets, including in California with the San Onofre Nuclear Generating Station (Payne 2020, Velez 2021). Notably, however, such an approach would provide a disincentive for investors to support future capital projects. An alternative to disallowing profit for the utility is implementing accelerated depreciation (as discussed in Section II.B.1.a), which has been widely used for coal plants and proposed for gas plants (Payne 2020). Finally, utilities may also be able to recover costs through the sale of land and gas assets, as previously accomplished during the decommissioning of the Montebello gas storage field, which was previously owned by SoCalGas (Long *et.al.* 2018: Appendix 2-9). Regardless of the approach taken, regulatory guidance on how stranded assets will be treated would assist system planning efforts (Hopkins *et.al.* 2020).

c. Option: Consider additional financial mechanisms and planning tools

Interested parties have also proposed utilizing other financial mechanisms for gas system planning. In particular, asset securitization has been proposed to support upfront consideration of asset decommissioning costs and accelerated depreciation (Gridworks 2021, Velez 2021, Hopkins *et.al.* 2020, Gridworks 2019). Asset securitization involves using low-interest ratepayer-backed bonds to compensate utilities for capital investments rather than including their value in the ongoing rate base with a rate of return (Bilich *et.al.* 2019). For utilities, asset securitization enables upfront cost recovery and frees up funding for other investments, while finalizing the value of those assets to insulate shareholders from additional asset costs (Bilich *et.al.* 2019, Payne 2020). For ratepayers, asset securitization reduces rates by removing those assets from the rate base and thereby removing further utility profits. The mechanism has precedent in California, having previously been used during utility deregulation and for coal plant retirements but does require legislative action (Bilich *et.al.* 2019, Payne 2020).

In addition to accelerated depreciation and asset securitization, interested parties have also proposed maintaining separate accounting mechanisms for already-existing infrastructure and any investments made after the decision to transition (similar to the "bright line" approach discussed in Section II.A.1.b). Under this proposal, regulators should only approve projects that would not entail costs for ratepayers after a specific year (Payne 2020). Further, stakeholder support exists for beginning to plan financially for gas workforce impacts through establishing decommissioning timelines and collecting funds for the transition (Velez 2021, Gridworks 2019). Workforce transition planning could build on the model previously set in the closure of the Diablo Canyon nuclear power plant, which provided funding for training for younger workers and retention benefits for seasoned workers to see the plant through the closure (Dalzell 2018). However, as mentioned above, there are significant challenges with establishing set timelines given current levels of uncertainty.

C. How to prune the gas system in the most cost-effective way?

The previous sections summarized a variety of proposals from interested parties and researchers that could be considered for inclusion into an overall strategy to keep rates just and reasonable while supporting California's climate goals and allowing for continued necessary maintenance of and investments in California's gas infrastructure.

These and other economic options have also been considered within the context of the technical approaches discussed in Section I.C.2 related to pruning the gas distribution system. Some alignments between gas system decommissioning and financing strategies have been proposed, and these are summarized here.

Financing approaches relevant to targeted decommissioning based on infrastructure criteria: Infrastructure that is prioritized for targeted decommissioning may still be in use for some period of time before that decommissioning occurs. If maintenance is needed, non-pipeline alternatives and shorter-term repairs could be considered (Karas *et.al.* 2021). When decommissioning does occur, abandonment proceedings may provide a useful framework to relieve utilities of the need to maintain that infrastructure by declaring it inconsistent with long-term gas planning strategies going forward (Payne 2020).

Financing approaches relevant to transitions away from certain end uses: Distinguishing among different gas end uses by need (*e.g.*, baseline versus luxury, as discussed in Section I.C.2) or the availability of alternatives may provide an opportunity to realign rate structures with specific services. Incorporating estimates of emissions (*e.g.*, from gas appliances with varying levels of efficiency) and public health impacts (*i.e.*, for indoor air pollution) into assessments related to continued gas system operation could enable a quantitative basis for differentiated rates and investment decisions (*e.g.*, by internalizing costs related to public health impacts into rates for gas stovetops). Limiting new gas connections could also prevent new customer investment in the gas system. However, if regulators decide that some new connections should be permitted, a tradeable market for gas connections could be established. In such a market, any new desired connection to the gas system would need to match with an equivalent or larger customer (specific criteria for "larger" could be determined within a regulatory process) who is willing to disconnect (Payne 2020). This approach could enable a market-oriented transition in which customers (including, for example, industrial customers or commercial customers such as restaurants) determine how much a given use is worth to them. A potential drawback to this approach is that if some core customers are willing to pay to stay on certain distribution lines that could preclude strategic decommissioning of those lines. To avoid this outcome, such a market approach could be limited only to large customers who do not use the distribution system.

Financing approaches relevant to sunset dates for system transition: Many of the financial mechanisms discussed above could apply to a target sunset date for gas decommissioning. These include accelerated depreciation with timelines aligned to sunset dates, increased financial transparency to determine planning and cost recovery options for existing infrastructure, and asset securitization to account for end-of-life costs.

Financing approaches relevant to developing gas alternatives: Hard-to-electrify uses of gas may ultimately be the ones to benefit from the development of zero-carbon gas alternatives. The establishment of a tradeable market for gas uses, as discussed above, could provide a market mechanism for industrial users to, over time, end up with remaining gas services that are tied to the availability of gas-like alternatives (Payne 2020).

Key considerations and questions for regulators and stakeholders include:

1. What programs currently exist that may create incentives for continued use of the gas system? To what extent are these still needed, and how could they be modified and/or eliminated? To what extent would legislative engagement on the interpretation of utilities' "obligation to serve" aid the development of paths forward?
2. To what extent, or by what processes, could non-pipeline alternatives fill in for system capacity needs?
3. What opportunities exist to reward better asset or system performance?
4. How are depreciation schedules currently set for different types of gas infrastructure assets, and what considerations are involved? How could accelerated depreciation schedules be implemented to ensure adequate infrastructure maintenance and just and reasonable rates for current and future ratepayers? Could accelerated depreciation be applied to existing assets?
5. How are different types of infrastructure and costs currently assigned to and borne by different types of customers (e.g., current versus future, core versus noncore, geographically

distinct)? How could these be adjusted to better support safety, just and reasonable rates, equity, and climate goals?

6. Could a tradeable market for gas connections or uses provide a mechanism for supporting hard-to-electrify gas users while assisting other users with a transition away from the gas system?

III. Other considerations for the gas system

The attention on long-term planning of the gas system in California is motivated by the need to reduce greenhouse gas (GHG) emissions in alignment with state climate goals. Beyond considerations specific to the technical and economic operation of gas system, considerations related to the emissions it produces and overall planning context are therefore critical to enabling this transition.

A. Continued GHG emissions from normal operations and methane leaks

GHG emissions can come from either normal gas system operation, wherein gas is burned for a productive end use, or from lost and unaccounted for (LAUF) gas, which tracks methane leaks along pipelines, from gas storage facilities, and other types of infrastructure (see Figure 1 for an estimate of unaccounted for gas in California). Emissions from the gas system are covered under California's cap-and-trade program, which encompasses both gas-fired electricity generators and gas delivery. Under the program, investor-owned gas utilities are allocated free emissions allowances in proportion to historical sales (C2ES 2021). While utilities are required to sell some of these allowances and use proceeds for ratepayer benefit, gas suppliers are not required to sell all their allocated allowances until 2030. Until that date, gas ratepayers are effectively paying for less than the full GHG emissions associated with their use of gas (CARB 2021a).

In the context of normal system operation, some of the most GHG-intensive gas uses are gas peaker plants, which are electric generators designed to ramp up and down quickly to compensate for variability in electricity demand and renewable energy production. To reduce system GHG emissions, interested parties have proposed evaluating the option to co-locate energy storage with gas peaker plants to enable smoother ramping and more efficient gas use (NASEM 2021, PSE Healthy Energy 2020).

Actions have been taken in California to mitigate methane leakage from gas infrastructure. Senate Bill 1371 mandated the CPUC to adopt rules to reduce methane emissions from regulated pipelines. In response, the CPUC initiated R.15-01-008, which resulted in the implementation of a methane leak abatement program (CARB 2021b). The program requires annual reporting of methane emissions from leaks, initiated 26 mandatory best practices for minimizing emissions due to leakage, and established a compliance plan and cost recovery process for these requirements (CPUC 2021g). The second stage of this program restricts rate recovery for PG&E and SoCalGas on unaccounted for gas beginning in 2025 (CARB 2021b). In addition to the CPUC's work, CARB has also set standards designed to reduce methane emissions from oil and gas production, processing, storage, and transmission compressor stations (CARB 2021c), and the California Legislature set an overall target to reduce methane emissions in the state to 40 percent below 2013 levels by 2030 (California

Legislature 2016). Stakeholder proposals to address methane leakage issues have acknowledged the work done in California on advanced leak detection and abatement (Karas *et.al.* 2021).

B. Alignment of planning processes to broad objectives

The gas system in California is overseen and managed by a variety of state agencies and industry participants (Table 8). Rigorous long-term planning and transparent decision-making about the future of the gas system is likely to require unprecedented coordination among these various actors (Karas *et.al.* 2021).

Table 8. Summary of state responsibilities related to California's gas system.

State entity	Brief description of tasks related to gas system
California Public Utilities Commission (CPUC)	Regulates utility rates, transportation, allocation of storage, core procurement, metering, and billing of gas; works to ensure that regulated services are delivered safely
California Energy Commission (CEC)	Forecasts gas supply and demand, supports RD&D efforts, certifies thermal power plants 50 MW or greater, performs statewide energy planning, sets codes and standards, including those related to energy efficiency
California Air Resources Board (CARB)	Conducts state greenhouse gas emissions inventory, regulates emissions of greenhouse gases and other air pollutants including from gas system and transportation fuels, and oversees the Low Carbon Fuel Standard for alternative renewable fuels
California Independent Systems Operator (CAISO)	Operates electric transmission system and manages participation of gas-fired electricity generators in electric markets
California Geologic Energy Management Division (CalGEM), within the California Department of Conservation	Regulates drilling, operations and maintenance, and closure of wells at gas storage fields
California Legislature	Promulgates laws, including those related to climate policy and greenhouse gas emissions, authorizes state funding and directs state agencies to take various actions

Interested parties have proposed that a potential step forward might be to initiate a gas system transition strategy (Aas *et.al.* 2020, Anderson *et.al.* 2021) that could consolidate existing relevant agency activities within an overall long-term gas planning effort (Gridworks 2021). Within this effort, interested parties suggest that agencies could initiate an integrated resource planning (IRP) process for gas, modeled on the existing electricity IRP process, and share data and analysis across state agencies (Gridworks 2019). Such an approach could also involve the development of a gas transition plan for California with contributions from CARB, the CEC, and the CPUC.

Other proposals include better integrating gas with electricity planning given the potential impacts of increased demand and costs to electricity systems (Wood Mackenzie *et.al.* 2018) and forming an independent planning committee that could vet gas demand forecasts, screen non-pipeline alternatives, and ensure all steps of the planning process are adequately transparent (Hopkins *et.al.* 2020).

Another approach was recently initiated in Colorado, where the state legislature passed legislation requiring comprehensive planning on the part of gas distribution utilities to meet GHG reduction targets (Colorado General Assembly 2021). Under the legislation, gas distribution utilities are required to file clean heat plans with the state's public utilities commission. The clean heat plans require comprehensive and integrated planning by gas utilities to mitigate baseline and projected emissions from methane leaks and CO_2 emissions from gas combustion and to use clean heat resources, such as electrification, efficiency and non-pipeline alternatives, and green hydrogen, to meet heat needs in buildings (Henchen & Overturf 2021, Jacus & Johnson 2021). While putting gas utilities at the core of the planning process, Colorado's legislation explicitly makes room for additional actions by the state's public utilities commission and input from other stakeholders, acknowledging that the clean heat plans are one part of an overall transition strategy (DiChristopher 2021).

Conclusion

California's vast gas infrastructure supplies critical uses including residential and small commercial heating, industrial services, baseload electricity generation, and electric balancing services for the state's renewable energy generation. More than 10,000 miles of interstate transmission pipelines and over 100,000 miles of distribution mains carry gas from neighboring regions and a dozen gas storage fields to customers. California's climate goals require reimagining how these end uses will continue to be met and how the future of the state's gas infrastructure will evolve.

To assist in this effort, the CPUC is conducting a proceeding on long-term gas planning in the state (CPUC 2020a). This proceeding is intended to evaluate how long-term planning for the future of the gas system should evolve, given the CPUC's mandate to ensure that regulated utilities provide safe and reliable services at just and reasonable rates while meeting California's climate goal of net zero emissions by 2045 and advancing equity in its programs (CPUC 2019b).

This white paper has summarized current discussions related to the future of the gas system and scoped out questions and considerations for regulators and stakeholders that may be relevant to the long-term gas planning OIR. These considerations range from technical needs for safety and reliability given expected demand on the gas system, to maintaining financial solvency and just and reasonable rates for customers, to minimizing GHG emissions and aligning coordination of planning processes across state agencies.

The issues described herein are complex; pathways forward will require engaged coordination among state agencies, gas and electric utilities, and stakeholders. The considerations and proposals discussed here are intended to help form a basis for discussion for these key questions. A primary goal of this work is the identification of key considerations and questions for regulators and stakeholders, which are included throughout. These considerations and questions are distilled from analyses of issues facing the gas system and summaries of existing proposals for gas system planning. They are intended to prompt discussion of how the various ideas discussed might contribute to a statewide strategy for meeting this challenge.

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Author bio

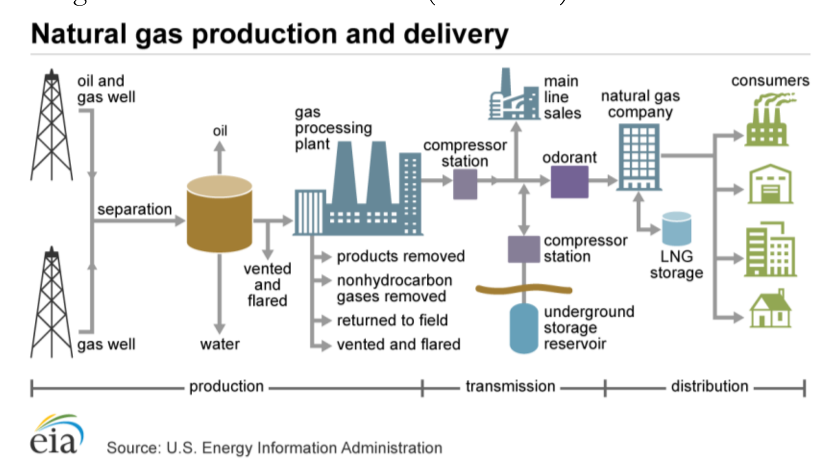
Anna M. Brockway is a PhD Candidate in the Energy & Resources Group at the University of California, Berkeley and a former Graduate Intern with the Gas Policy and Reliability team in the Energy Division of the California Public Utilities Commission. Anna's dissertation focuses on how our energy systems are changing—and how they must change—in response to existing and emerging stressors. Her work has focused on stressors to the conventional operation of electric power systems (climate change, renewable energy, and electrification) and how we may adapt to them while ensuring reliability and cost-effectiveness and enabling increased sustainability and equity. Her work in these areas has solidified her interest in how decision-making and planning for the future of energy systems will need to evolve amid growing risks and public scrutiny.

Prior to graduate school, Anna was a SunShot Science & Technology Policy Fellow at the U.S. Department of Energy's Solar Energy Technologies Office in Washington, DC. Anna holds an MS in Electrical Engineering ('19) and an MS in Energy & Resources ('17) from UC Berkeley, along with a BS in chemistry and a minor in philosophy from Haverford College.

Appendix A: Gas infrastructure

Figure 8. Gas infrastructure in California (reproduced from U.S. DOE 2015). California has 14 gas storage reservoirs in 12 storage fields (EIA 2021).

Figure 9. Schematic of gas infrastructure in California (EIA 2020a).



Appendix B: Gas system data request

The Gas Policy & Reliability team within the California Public Utility Commission's Energy Division is in the process of submitting a data request to regulated gas distribution utilities within California. The goal of this data request is to gather information about the gas transmission and distribution systems that includes, but is not limited to:

1. Identifying Information:
    a. Pipeline or other infrastructure name and/or identifying information, including alignment with federal HIFLD database
2. Physical Information:
    a. Geographic location (in a separate GIS file)
    b. Pipeline length
    c. Service area, including whether the pipeline serves a High Consequence Area (PHMSA 2011)
    d. Connectivity information to upstream and downstream pipeline sections, valves, and other gas infrastructure
    e. Pipeline diameter, material type and age
3. Operational Information:
    a. Characteristics including minimum and maximum pressures
4. Safety and Maintenance Information:
    a. Risk assessment/integrity management information, including score(s)
    b. Date(s) and type(s) of recent testing conducted
    c. Date(s) and type(s) of major repairs, replacements, or maintenance work
    d. Planned investments and their status
5. Usage Information:
    a. Available capacity, including capacity reductions or times out of service Usage/throughput
    b. Customers served, by customer type
6. Costs Information:
    a. Capital costs
    b. Operations and maintenance costs

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