GAS RESOURCE AND INFRASTRUCTURE PLANNING FOR CALIFORNIA

A Proposed Approach to Long-Term Gas Planning

JANUARY 2021

GRIDWORKS

OVERVIEW

California will need to make substantial changes to its current gas supply and delivery system in order to meet the state's climate and equity goals. This represents a huge challenge. We urge leaders throughout California to leverage the content herein to accelerate long-term gas planning.

FIGURE ES-1. *Gas Resource and Infrastructure Plan Process Overview*

Gridworks' 2019 report *California's Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller* concluded that California must manage the transition towards a decarbonized fossil gas system to "minimize societal costs and unfair burdens on the remaining gas customers and workers, while also ensuring greenhouse gas (GHG) emissions reductions, air quality improvements, and equitable outcomes among California's communities."[1] The findings and recommendations of the 2019 report have only grown more critical and urgent.

Importantly, a gas transition strategy must maintain affordable gas rates by decreasing system costs relative to the current trajectory for gas delivery system spending, while increasing non-ratepayer revenue streams to avoid stranded gas system costs. This report focuses on a planning process to achieve decreased system costs; the challenge of increasing non-ratepayer revenue to avoid stranded gas system costs remains a significant challenge to address in parallel.

The Gas Resource and Infrastructure Plan (GRIP) process (Figure ES-1) provides a guide to how California might thoughtfully, empirically, and pragmatically consider and decide the future of its gas resources and delivery systems. The five-step process will require close coordination and collective action from Joint Agencies including the California Public Utilities Commission (CPUC), California Energy Commission (CEC), California Air Resources Board (CARB), and the California Independent System Operator (CAISO). Table ES-1 summarizes the objectives for each step in the GRIP process.

1 Gridworks, September 2020, California's Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller, page 1, https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

TABLE ES-1. *Objectives for the Gas Resource and Infrastructure Plan Process*

STEP 1	The Joint Agencies: (1) identify legislative and statutory requirements and adopt guiding policy objectives and evaluation criteria to be used to evaluate proposed Gas Resource and Infrastructure Plans, and (2) through a public process at the CPUC, adopt gas planning scenarios to analyze in the GRIP process. Regulated gas utilities: (1) report on current gas demand, and (2) present concise descriptions of their current gas systems and currently approved or planned changes to those systems, including key operational considerations.
STEP 2	Joint Agencies and the utilities collaboratively develop future forecasts of gas demand and supply under each of the adopted planning scenarios.
STEP 3	Utilities develop initial strategies for Joint Agency review and approval for reducing future infrastructure investments and revenue requirements as system throughput declines in order to avoid end user rate escalation and stranded costs.
STEP 4	Joint Agencies, along with stakeholders, analyze the monetary and non-monetary costs and benefits of the various scenarios using the evaluation criteria adopted in Step 1.
STEP 5	CPUC incorporates stakeholder input into a Commission decision that approves gas system decarbonization strategies.

The GRIP process would align with a CPUC proceeding that includes two tracks. Track 1 would address baseline issues, establish policy guidance, and select scenarios for further analysis and Track 2 would analyze the scenarios with regard to the adopted policy objectives and adopt solutions (Figure ES-2). The inaugural GRIP is estimated to require about two years to be completed. Future iterations of the GRIP could reasonably be expected to take about 18 months.

FIGURE ES-2. *Proposed GRIP Timeline*

The GRIP planning horizon should extend out to at least 2045, with differing objectives for near-term (1-5 year) versus longer-term (5-10+ year) planning horizons. For instance, planning on a one to five-year horizon should provide information that offers decision-makers and stakeholders greater context with which to evaluate requests made in rate cases for system investments. For planning on five to 10+ year horizons, the GRIP should consider options for non-pipes solutions, avoiding future stranded assets, and blending of alternative gaseous fuels and other technologies to decarbonize the energy sector.

STAKEHOLDER ENGAGEMENT

Stakeholder engagement is integral to the GRIP process and should be conducted at two levels - one broad outreach initiative and one focused pilot engagement initiative. The broad outreach initiative would educate customers and community-based organizations (CBOs) about the basics of the gas delivery system, including decarbonization goals. The focused pilot engagement initiative would include closer coordination with CBOs to design, implement, and evaluate pilots.

It will take extra time and resources for Joint Agencies and utilities to build trust with CBOs and communities, especially in historically underserved populations. Importantly, just as Joint Agencies and utilities pay consultants for technical and analytical expertise, Joint Agencies and utilities must compensate CBOs for their knowledge and expertise in working with communities. Joint Agencies and utilities should recognize that investment into CBOs to engage communities in the gas transition is a necessary cost for an equitable and inclusive decarbonized energy future.

DATA AND ANALYSIS

The data requirements and analytical capabilities necessary to conduct long-term gas planning will also take time and resources to develop. State agencies and gas utilities will need to develop granular gas demand forecasts, potentially by geographic region, to better understand where infrastructure improvements are necessary and where infrastructure may be retired. This type of analytical capability may take multiple years to develop and refine and Joint Agencies and utilities should immediately start developing the skills, models, and tools required.

Data and analysis must be complemented with pilot projects, especially in disadvantaged communities, to help to determine which approaches might be most successful for reducing revenue requirements in the future, with the results of those pilots feeding into future iterations of the GRIP.

FINANCIAL MECHANISMS

The inaugural GRIP evaluation and resulting CPUC decision need to establish a clear pathway for implementing financial mechanisms to manage the costs of the gas transition, including updating depreciation schedules, aligning shareholder interests with non-pipeline alternatives, and securitization of remaining asset value. These approaches are expected to be updated over time and different approaches may be warranted for existing versus future assets.

Development of, and recommendations from, the GRIP may catalyze regulatory reform activities in other proceedings, including General Rate Cases and the Triennial Cost Allocation Proceeding (TCAP) at the CPUC. The CPUC could direct the gas utilities to initiate a short-term (three to six months) collaborative working group process to update gas rate design and cost allocation to minimize and stabilize gas rate increases.

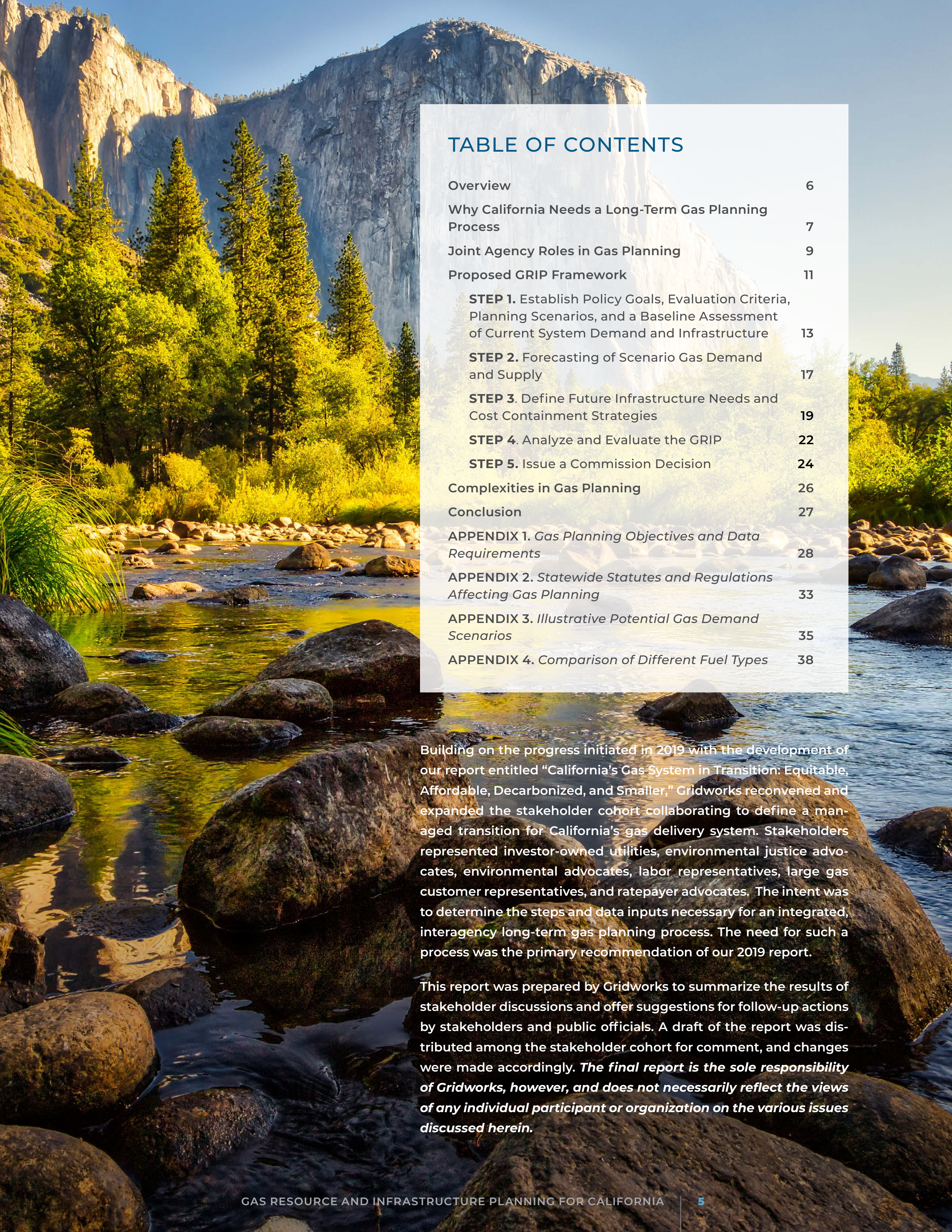


TABLE OF CONTENTS

Building on the progress initiated in 2019 with the development of our report entitled “California’s Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller,” Gridworks reconvened and expanded the stakeholder cohort collaborating to define a managed transition for California’s gas delivery system. Stakeholders represented investor-owned utilities, environmental justice advocates, environmental advocates, labor representatives, large gas customer representatives, and ratepayer advocates. The intent was to determine the steps and data inputs necessary for an integrated, interagency long-term gas planning process. The need for such a process was the primary recommendation of our 2019 report.

This report was prepared by Gridworks to summarize the results of stakeholder discussions and offer suggestions for follow-up actions by stakeholders and public officials. A draft of the report was distributed among the stakeholder cohort for comment, and changes were made accordingly. ***The final report is the sole responsibility of Gridworks, however, and does not necessarily reflect the views of any individual participant or organization on the various issues discussed herein.***

OVERVIEW

Today California's gas delivery system is extensive, and – where it extends – ubiquitous, serving well over 10 million individual residential, commercial, industrial, electric generation, and transportation customers and delivering an average of over 5 billion cubic feet (Bcf) of methane each day.[2] The system provides several critical energy services, including space and water heating for residential and commercial buildings; flexible electricity generation; and process steam, heat, and power for industrial uses. However, until recently, there has been limited regulatory focus on the gas system, aside from increased attention to system safety in the wake of the pipeline explosion at San Bruno (2010) and the storage field methane leak at Aliso Canyon (2015-16).

In January 2020 the California Public Utilities Commission issued Order Instituting Rulemaking (R.) 20-01-007. The Order identified the need to conduct Long-Term Gas Policy and Planning, with the intent to "implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals."[3]

This Order follows Gridworks' report *California's Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller* which concluded:

> "The volume of gas flowing through California's gas delivery system (gas "throughput") will decline dramatically over time in response to state and local policies. The pressing question for California is how we can manage this transition to minimize societal costs and unfair burdens on the remaining gas customers and workers, while also ensuring greenhouse gas (GHG) emission reductions, air quality improvements, and equitable outcomes among California's communities."[4]

The transition and how it is managed are particularly important for low-income customer and disadvantaged communities[5] who, without changes to stakeholder engagement and decision-making processes, are least likely to benefit from California's transition to a clean energy future.[6]

To assist the Commission in its leadership of Long-Term Gas Policy and Planning, Gridworks convened a diverse group of stakeholders and facilitated their consideration of how such planning should be conducted. This report reflects the input of these stakeholders, organized and edited by Gridworks, into a **Gas Resource and Infrastructure Planning (GRIP)** process. The report provides a planning process which:

- Supports achieving the state's adopted law and goals;
- Recognizes the need to consider and weigh uncertainty through scenario analysis;
- Creates a consistent approach to evaluating gas portfolios and infrastructure plans, guided by shared principles; and
- May be practically implemented and adapted over time.

In short, this is a guide to how California might thoughtfully, empirically, and pragmatically consider and decide the future of its gas resources and delivery systems. Appendix 1 provides a high-level overview of the proposed GRIP process and related data inputs and outputs.

---

2 California Gas and Electric Utilities, 2020 California Gas Report.

3 Assigned Commissioner's Scoping Memo and Ruling in R.20-01-007, dated April 23, 2020, page 2.

4 Gridworks, September 2020, *California's Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller*, page 1, https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

5 For the purposes of this report, "low-income and Disadvantaged Communities" is not explicitly defined. Disadvantaged Communities are generally considered to be the top 25% of census tracts that face disproportionate economic, health, and pollution burdens; and census tracts that have the highest 5% pollution burden; and tribal communities (See: https://oehha.ca.gov/calenviroscreen/sb535). However, work in the San Joaquin Valley Affordable Energy Pilots has shown that defining "communities" based on Census Designated Places presents a barrier to equitable access to energy services. Refer to Pilot Team Notification of *Ex Parte* Communications, filed October 7, 2020 and available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K622/351622380.PDF

6 California Environmental Justice Alliance (CEJA), November 2020, *Building a Just Energy Future: A Framework for Community Choice Aggregators to Power Equity and Democracy in California*, page 11, available at: https://caleja.org/wp-content/uploads/2020/11/CEJA-CCA-REPORT-SINGLE-PAGE.pdf.

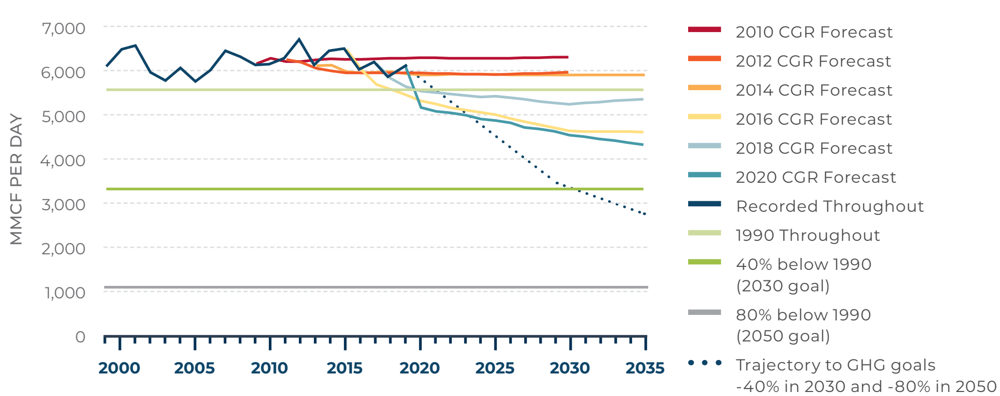
WHY CALIFORNIA NEEDS A LONG-TERM GAS PLANNING PROCESS

The combustion of fossil gas is responsible for a major share of emissions from the electricity, buildings, and industrial sectors of California's economy, resulting in more than 100 million tons (MMT) of carbon dioxide equivalent (CO_2e) emissions per year.[7] Additional greenhouse gas (GHG) emissions, estimated at 7.7 MMT of CO_2e per year, result from lost and unaccounted for (LUAF) gas leaked from the system.[8,9] Further, the combustion of fossil gas is responsible for considerable emissions of criteria pollutants, including nitrogen oxides (NO_x) and particulate matter, which disproportionately impact the health and well-being of low-income and disadvantaged communities. As such, California will need to make substantial changes to its current gas supply and delivery system in order to meet the state's climate and equity goals. This represents a huge challenge.

There is no real question that fossil gas throughput will decline — only how much and how quickly. The *2020 California Gas Report* forecasts a modest decline in gas throughput of 1.0 percent per year, cumulatively reducing throughput by approximately 17% between 2020 and 2035 (Figure 1).[10] Looking further, the Energy Futures Initiative report, *Optionality, Flexibility, and Innovation: Pathways for Deep Decarbonization for California*, forecasts a 50-75% decline in gas throughput by 2050 (Figure 2).[11]

FIGURE 1. *California Gas Report Throughput Forecasts.*
Source: Crossborder Energy, 2020

CALIFORNIA TOTAL INCLUDING UTILITY BYPASS



7 California Air Resources Board Greenhouse Gas Inventory Query Tool (2000-2017), Emissions from Fuel Combustion, Natural Gas, Accessed October 6, 2020.

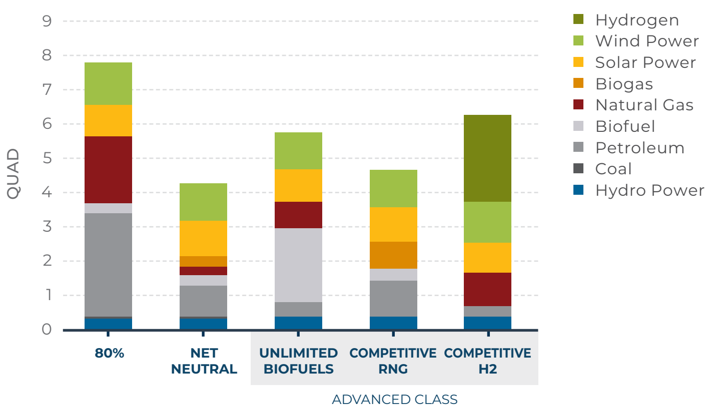
8 California Public Utilities Commission and California Air Resources Board Joint Staff Report, January 2020, ***Analysis of the Utilities' June 17, 2019 Natural Gas Leak and Emission Report***, page 5, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Safety/Risk_Assessment/Methane_Leaks/CPUC%20and%20CARB%20Joint%20Staff%20Report.pdf.

9 Methane emissions are even larger when considering the gas production facilities supplying fossil gas burned in California. Over 90% of methane emissions from gas production occur outside of the state because California imports more than 90% of its gas supplies. Nonetheless, these out-of-state emissions result from the burning of fossil gas within California. These out-of-state methane emissions are not in the official CARB GHG inventory for California, but there are clearly significant societal and climate benefits from reducing these out-of-state methane emissions caused directly by fossil gas use in California. Recent estimates are that methane leakage from both the production and pipeline infrastructures for fossil gas has the same equivalent CO_2 emissions over a 20-year time horizon as the end-use combustion of the fossil gas. See: R.A. Alvarez et al., Science, 10.1126/science.arr7204 (2018).

10 California Gas and Electric Utilities, 2020 California Gas Report, page 4.

11 Energy Futures Initiative (EFI), ***Optionality, Flexibility and Innovation: Pathways for Deep Decarbonization in California***, May 2019, Appendix A, Figure A-5, page 314. The EFI Study models four cases that use different technology pathways to meet the state's 2050 climate goals. These emphasize, in order, electrification, biofuels for transportation, renewable natural gas, and hydrogen. In all four of these cases, the amounts of fossil natural gas and biogas that would use the gas pipeline system range from 0.6 quadrillion BTUs (in the Net Neutral [electrification] case) to 1.1 quadrillion BTUs (in the Competitive H2 case). This is equivalent to a range of throughputs over the state's gas pipeline system in 2050 of 1,600 to 3,000 MMcf/day, representing decreases of about 50% to 75% compared to historical throughput of about 6,000 MMcf/day.

FIGURE 2. *California's Primary Energy Consumption in 2050.*
Source: Energy Futures Initiative, 2019



These reductions are primarily driven by California's ambitious climate and energy policies, including Senate Bill (SB) 350 (De Leon, 2015), SB 32 (Pavley, 2016), SB 100 (De Leon, 2018), and Executive Order B-55-18 (Brown, 2018).[12] A more detailed list of statewide statutes and regulations affecting gas planning and operations is presented in Appendix 2. These state policies are complemented by local mandates and reach codes requiring all-electric new construction, thereby eliminating fossil gas infrastructure in new residential buildings and accelerating the downward trend in gas demand.

At the same time that gas demand and throughput are projected to decline over time, the costs of operating a safe and reliable gas delivery system in California continue to rise. If the gas delivery system's footprint remains static while throughput declines, the shrinking base of gas customers will ultimately face higher rates and unaffordable gas bills. These rate increases will particularly impact those who are already experiencing a disproportionate energy burden and unable to afford a transition to clean heating fuels. Therefore, a gas transition strategy must necessarily include a component that maintains affordable gas rates (see Principles for Gas Planning). Mitigating and stabilizing rate impacts will require decreasing system costs relative to the current trajectory for gas delivery system spending, while increasing non-ratepayer revenue streams to avoid stranded gas system costs.

State agencies are increasingly recognizing the need to reduce reliance on fossil gas and related infrastructure. The California Air Resources Board (CARB), the agency tasked with directing the state's GHG reduction efforts, recently recognized that achieving California's climate goals will require less reliance on fossil gas and that replacing fossil gas with zero carbon electricity would result in significant health benefits and improvements to indoor air quality.[13] Additionally, the California Energy Commission (CEC) recently issued a grant funding opportunity to develop "multi-disciplinary, strategic approaches for stakeholders and decision makers to determine where trimming portions of natural gas infrastructure is plausible, economically viable, and customer-supported with clearly identifiable rate payer benefits."[14] These actions reflect the much-needed leadership critical to a managed transition to a decarbonized gas delivery system.

12 SB 350 requires a doubling of gas efficiency savings by 2030. SB 32 requires the state to reduce GHG emissions to 40% below 1990 levels by 2030. SB 100 requires 100% renewable electricity by 2045. Executive Order B-55-18 establishes a goal of a carbon neutral economy by 2045.
13 CARB Resolution 20-32, November 19, 2020, page 2, available at: https://ww3.arb.ca.gov/board/res/2020/res20-32.pdf.
14 Grant Funding Opportunity GFO-20-503, December 2020, Strategic Pathways and Analytics for Tactical Decommissioning of Portion of Natural Gas Infrastructure, PIER Natural Gas Program, available at: https://www.energy.ca.gov/solicitations/2020-12/gfo-20-503-strategic-pathways-and-analytics-tactical-decommissioning-portions.

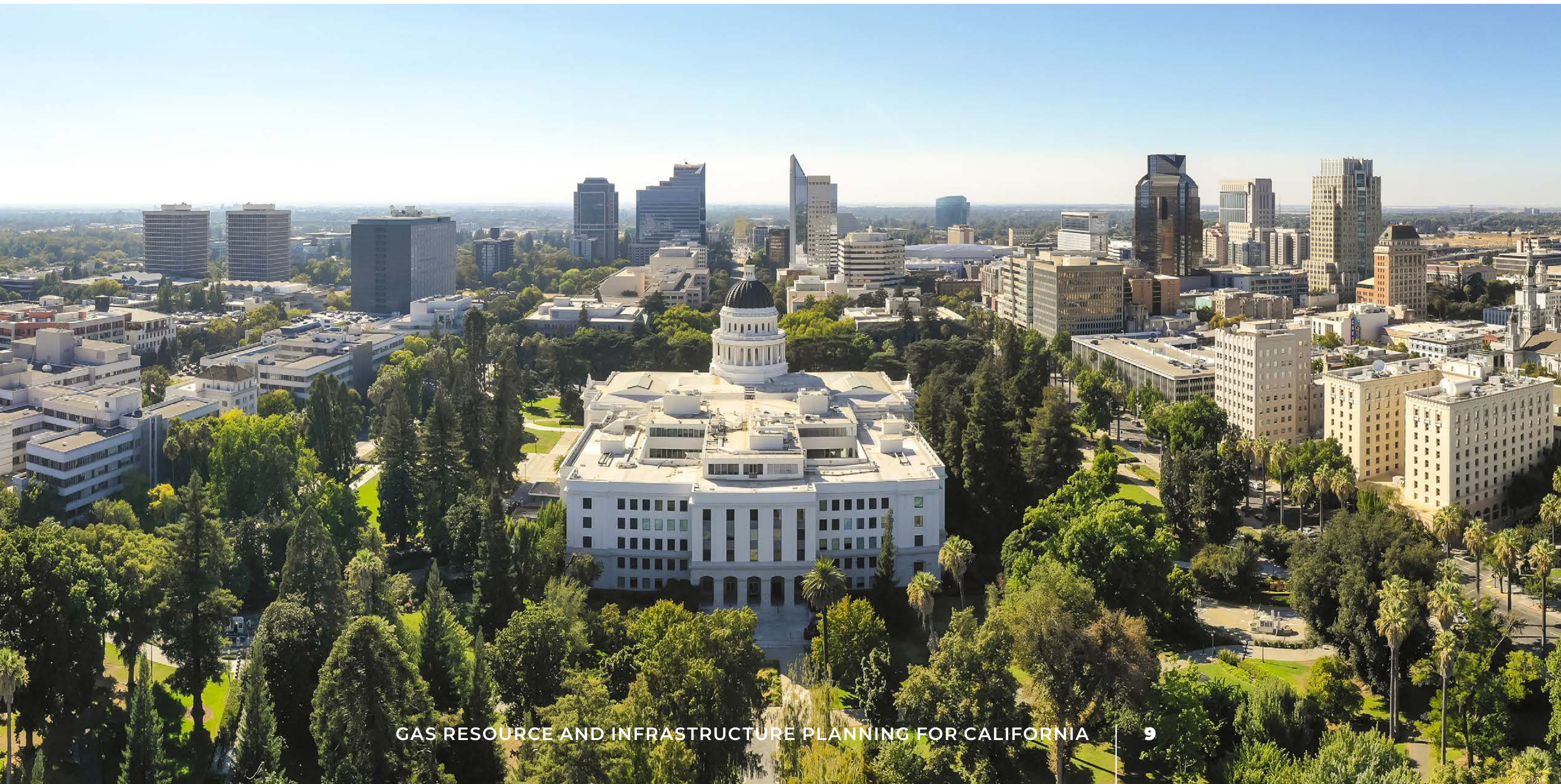
JOINT AGENCY ROLES IN GAS PLANNING

Implementation of the GRIP framework will require a multi-agency effort involving, at minimum, the CPUC, CEC, CARB, the California Independent System Operator (CAISO), herein referred to as the "Joint Agencies," and potentially others, including outside consulting assistance. While the GRIP is proposed within the context of an upcoming CPUC proceeding, no single agency has the jurisdiction and expertise to manage this process alone and a truly collaborative effort will be needed to succeed.

Table 1 indicates the respective roles that each agency would serve within the gas planning process. The goal would be for the Joint Agencies to develop a set of state strategies for gas system decarbonization that addresses two key parameters: (1) which customers, sectors, and related end uses will the future gas system serve; and (2) what fuels will be used and what infrastructure will be needed to deliver those fuels in the future gas system.

TABLE 1. *State Agency Roles for Long-term Gas Planning*

	CPUC	CEC	CARB	CAISO
Applicable Jurisdiction	Regulation of investor-owned utilities	Statewide energy planning; oversight of publicly-owned utilities	Achievement of GHG reduction goals; enforcement of air quality standards and regulation	Operation of the electric grid
Gas Planning Function	Decide on rate cases, safety and reliability standards, rate design, and cost allocation; approve policies, pilots, and programs to enable a managed gas transition	Model system-wide gas demand forecast to inform rates; conduct research and development to support a managed gas transition	Establish emissions budgets for the electricity, industry, and buildings sectors	Provide input on electric generation reliability standards and necessary load balancing services from gas system resources



PRINCIPLES FOR GAS PLANNING

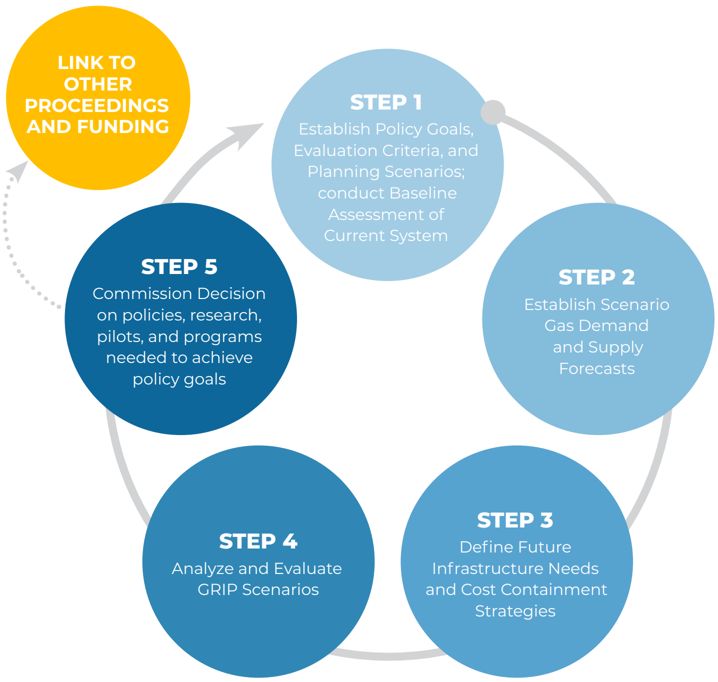
Within the GRIP, the Joint Agencies' task will be to determine an optimized combination of approaches to achieve the state's GHG and air quality requirements, while continuing to provide energy services consistent with customer needs, affordability, fuel availability, gas system safety and operations, and equity – particularly for low-income customers and disadvantaged communities who have suffered disproportionate impacts from industrial pollution. The stakeholder cohort developed the following guiding principles for evaluating potential future scenarios for the evolution of the California gas system:

1. Continue to reduce gas safety risks, assure continued reliability of gas service, and reduce gas leaks that contribute to climate change.
2. Minimize and stabilize rate increases for those who continue to use gas for essential energy services.
3. Manage the gas system transition to achieve the state's GHG and criteria pollutant reduction objectives.
4. Ensure an adequate gas industry workforce with all of the necessary skills is available at all times to operate and maintain the gas system safely, reliably, and with fewer leaks. This includes minimizing any future adverse impacts on gas workers, retaining skilled workers, and providing a just transition for any displaced gas workers.
5. Ensure access to quality and affordable energy services and new technologies, resilience, air quality protection, and an equitable and just transition for low income and disadvantaged communities.
6. Mitigate any adverse economic impacts in terms of increasing cost of living in California, favoring out-of-state electric generation, and/or other forms of emissions "leakage" to other jurisdictions.
7. Maintain financially viable gas utilities during the transition.

These principles provide a starting point for Joint Agencies to articulate guiding policy goals and plan evaluation criteria at the outset of the GRIP process (see Step 1). Establishing shared policy drivers and evaluation criteria will provide the framing and context necessary to focus stakeholders' contributions to the gas transition.

PROPOSED GRIP FRAMEWORK

FIGURE 3. *Gas Resource and Infrastructure Plan Process Overview*



A conceptual graphic representation of the proposed multi-step GRIP framework is shown in Figure 3. This approach builds on relevant electric planning process analogues and includes additional considerations specific to gas planning. The cycle would be repeated every few years, as determined by the Joint Agencies, with feedback and data from previous cycles, pilots, and research results serving as inputs to future planning cycles.

These steps would align with a CPUC proceeding that includes two tracks. Track 1 would address baseline issues, establish policy guidance, and select scenarios for further analysis and Track 2 would analyze the scenarios with regard to the adopted policy objectives and adopt solutions. The GRIP process is envisioned to require 4-6 months to complete Track 1 and 14 to 19 months for Track 2 (Figure 4). The outcome from each GRIP cycle will result in Commission guidance that directs the utilities to pursue a preferred set of decarbonization strategies and investments in the gas delivery system.

FIGURE 4. *Proposed GRIP Timeline*

The GRIP planning horizon should extend out to at least 2045, with differing objectives for near-term (1-5 year) versus longer-term (5-10+ year) planning horizons. For instance, planning on a one to five-year horizon should provide information that offers decision-makers and stakeholders greater context with which to evaluate requests made in rate cases for system investments. For planning on five to 10+ year horizons, the GRIP should consider options for non-pipes solutions, avoiding future stranded assets, and blending of alternative gaseous fuels and other technologies to decarbonize the energy sector.

STAKEHOLDER ENGAGEMENT IN THE GRIP PROCESS

Stakeholder engagement must be an overlay across each step of the GRIP process. The stakeholder engagement process should empower communities to make educated choices about their energy options and promote self-determination. Engagement should also be streamlined and coordinated with other energy planning activities, such as the electric IRP process or local building electrification efforts. The outcomes of the GRIP must protect communities from further harm, and mitigate existing and past harms.

Joint Agencies and utilities will need to thoughtfully engage with community-based organizations (CBOs) that are qualified to represent the interests of vulnerable populations. In a recent report by the California Environmental Justice Alliance (CEJA), they emphasize that "CBOs are trusted leaders in their communities and are often the best positioned to effectively conduct outreach."[15] Importantly, just as Joint Agencies and utilities pay consultants for technical and analytical expertise, Joint Agencies and utilities must compensate CBOs for their knowledge and expertise in working with communities.[16,17]

Stakeholder engagement in the GRIP process should be conducted at two levels - one broad outreach initiative and one focused pilot engagement initiative. Multi-pronged stakeholder engagement initiatives would recognize that not every stakeholder will want to participate in the GRIP process, but all stakeholders who want to participate in the GRIP process should be empowered and educated to do so in a meaningful manner.

The broad outreach initiative should educate customers and CBOs about the basics of the gas delivery system, including decarbonization goals. Additionally, this outreach initiative should educate customers on their energy options within the context of decarbonization goals, the expected rate impacts from customers' energy choices, and mechanisms available to mitigate any rate impacts. The broad outreach initiative should seek to form partnerships with CBOs already working in communities to facilitate outreach.

15 CEJA, November 2020, *Building a Just Energy Future: A Framework for Community Choice Aggregators to Power Equity and Democracy in California*, page 6, available at: https://caleja.org/wp-content/uploads/2020/11/CEJA-CCA-REPORT-SINGLE-PAGE.pdf.

16 Mohnot, S., Bishop, J., and Sanchez, A., August 2019, *Making Equity Real in Climate Adaptation and Community Resilience Policies and Programs: A Guidebook*, Greenlining Institute, page 46, at: https://greenlining.org/wp-content/uploads/2019/08/Making-Equity-Real-in-Climate-Adaption-and-Community-Resilience-Policies-and-Programs-A-Guidebook-1.pdf

17 The CPUC's existing intervenor compensation mechanism is a poor fit for compensating CBOs for stakeholder engagement because compensation levels are only decided after a Final Decision is issued and parties are able to demonstrate their contributions to that Final Decision. Parties must invest in their engagement first, without knowing whether or when they will be able to recover resources spent. Further, costs incurred for supporting

The focused pilot engagement initiative should include closer coordination with CBOs to design, implement, and evaluate pilots. CBOs should be engaged to support outreach, education, enrollment, and ongoing technical support for pilot participants. Lessons learned from the San Joaquin Valley Affordable Energy Pilots and the forthcoming process evaluation should be applied.[18]

It will take extra time and resources for Joint Agencies and utilities to build trust with CBOs and communities, especially in historically underserved populations. Joint Agencies and utilities should recognize that investment into CBOs to engage communities in the gas transition is a necessary cost for an equitable and inclusive decarbonized energy future.

STEP 1 ESTABLISH POLICY GOALS, EVALUATION CRITERIA, PLANNING SCENARIOS, AND A BASELINE ASSESSMENT OF CURRENT SYSTEM DEMAND AND INFRASTRUCTURE

FIGURE 5. *GRIP Step 1 Outcomes and Outputs*

OUTCOMES		DATA OUTPUTS
JOINT AGENCIES	**UTILITIES**	• Recorded average and peak day demand by geography • Core and non-core customers on each rate schedule, categorized by service level • Leaks discovered and repaired • Aldyl-A pipeilne to be replaced • Gas supply by source and recorded deliveries • Net Book Value of Assets • GHG and criteria pollutant emissions • Number and classification of gas employees
1. Adopt Policy Goals and Evaluation Criteria 2. Adopt Gas Planning Scenarios	1. Report on Current Gas Demand 2. Present a Summary of the Gas System and Planned and Approved Investments	

Like most planning processes, the GRIP would begin with a description and understanding of the system as it exists today. Objectives and outcomes for Step 1 include:

A. The Joint Agencies identify legislative and statutory requirements and adopt guiding policy objectives and evaluation criteria to be used to evaluate proposed Gas Resource and Infrastructure Plans;

B. Regulated gas utilities report on current gas demand;

C. Regulated gas utilities present concise descriptions of their current gas systems and currently approved or planned changes to those systems, including key operational considerations; and

D. The Joint Agencies, through a public process at the CPUC, adopt gas planning scenarios to analyze in the GRIP process.

Objective A | *The Joint Agencies Identify Legislative and Statutory Requirements and Adopt Guiding Policy Objectives and Evaluation Criteria to be Used to Evaluate Proposed Gas Resource and Infrastructure Plans*

One essential task to anchor the GRIP process will be for the Joint Agencies, through a public process, to identify all controlling legislative and statutory requirements and adopt a set of policy objectives and evaluation criteria by which different future scenarios for the gas system can be analyzed and compared. The policy goals and requirements identified at this early stage of the process would form the basis of the

18 Evergreen Economics is developing a process evaluation for the San Joaquin Valley Disadvantaged Communities Pilots. *Refer to SJV DAC Pilot Projects Process Evaluation* for more information on the research plan: https://pda.energydataweb.com/api/view/2432/SJV%20DAC%20Final%20Research%20Plan%20101220.pdf.

criteria by which the Joint Agencies would evaluate the pros and cons of the various scenarios analyzed. Often tradeoffs will have to be made between important objectives, just as regulation has traditionally had to weigh the balance between a higher level of system reliability and increased customer costs. In some instances, state law may simply require the achievement of a certain objective, regardless of other competing values.

It will be important for the agencies to specify these legal requirements, policy goals, and evaluation criteria at the outset, in order to avoid a situation where parties are relying on different sets of goals in their evaluations of the various scenarios. The current policy drivers of system change, such as the statutes listed in Appendix 2 and the guiding principles set forth above, provide a useful starting point to identify these policy goals.

POSSIBLE QUESTIONS FOR GRIP EVALUATION

Using the principles agreed upon by the stakeholder cohort, the Joint Agencies may evaluate proposed GRIPs by asking:

- Does the plan continue to reduce gas safety risks, assure continued reliability of gas service, and reduce methane leaks that contribute to climate change?
- Does the plan minimize and stabilize rate increases for those who continue to use gas for essential energy services?
- Does the plan manage the gas system transition to achieve the state's GHG and criteria pollutant reduction objectives?
- Does the plan ensure an adequate gas industry workforce is available at all times to operate and maintain the gas system safely, reliably, and with fewer leaks? Does it minimize any future adverse impacts on gas workers, retain skilled workers, and provide a just transition for any displaced gas workers?
- Does the plan ensure access to quality and affordable energy services and new technologies, resilience, air quality protection, and an equitable and just transition for low-income and disadvantaged communities?
- Does the plan mitigate any adverse economic impacts in terms of increasing the cost of living in California, favoring out-of-state electric generation, and/or other forms of emissions "leakage" to other jurisdictions?
- Does the plan maintain a financially viable gas utility during the transition?

Objective B | *Regulated Gas Utilities Report on Current Gas Demand*

To report on current gas demand, regulated gas utilities would present a breakdown of actual average and peak day gas demand, distinguished by customer classes, end use applications, and geographic locations (where feasible). Data required for this analysis, most of which already exist in the California Gas Report or related workpapers, would include:

1. Recorded average and peak day gas demand for the most recent five years.
2. A geographic representation of current average and peak day gas demand, by city, county, company division or other relevant geographic indicator (as available), including expected impacts of local government decarbonization initiatives.

3. Number of customers for each rate schedule and in total, for the most recent recorded year, broken down by core and non-core.
4. Numbers of core and non-core customers, by class, served directly from: backbone transmission, local transmission, or distribution. Number of distinct distribution systems across the service area and percentage of those that include at least one non-core customer.[19]
5. Geographic representation of the locations of current non-core customers by city, county, company division or other geographic indicator (as available), including service level (backbone, local transmission, or distribution).

Objective C | *Regulated Gas Utilities Present Concise Descriptions of the Current Gas Systems and Currently Approved or Planned Changes to those Systems, including Key Operational Considerations*

To develop a clearer understanding of current gas system investment plans, the regulated gas utilities would identify their currently approved and/or best estimates of their future anticipated (1-5 year) investments in system components and their expected drivers, as well as contracted supply sources and their durations (if over one year). Key operational practices and constraints would also be described. Further, current rate base assets and their associated depreciation timelines should be summarized to provide a picture of existing asset costs over time. Most of this information should be readily available from regulatory filings or utility records and would be provided by the regulated utilities, but agency staff and interested parties would be able to add information to the record as appropriate.

Data required to achieve this objective includes:

6. Current (end of last calendar year) Net Book Value of Assets by function, including backbone transmission, local transmission, storage, distribution, customer-related (if separate from distribution), and other (including relevant components by category).
7. Projected end of year net book value of assets by category, assuming no additional investment, for each year until all assets are fully depreciated at existing depreciation rates.
8. Percentage utilization of system capacity on a peak day, disaggregated by functional components and geographical location to the extent possible.
9. Estimate of expected annual capital additions for each of the next ten years, broken down by function and by purpose (e.g., safety and compliance, new customer connections, load growth, etc.).
10. Leaks:
    a. Number of leaks discovered per year for the last five years.
    b. Number of leaks repaired per year for the last five years.
    c. Estimated gas losses due to leaks for the last five years.
    d. Total lost and unaccounted for (LUAF) gas for the last five years.
11. Estimated miles of Aldyl-A pipe in the system that will need to be replaced over the next ten years.
12. Gas supply by source (producing basin or delivery pipeline) for the most current recorded year and any expected changes over the next five years.
13. Most recent recorded year's deliveries of alternative gaseous fuels (other than fossil gas), by type and source of fuel and by customer class if available. Expected changes over the next 10 years.
14. Current total base margin (transportation revenue requirement).
15. Current cost of commodity (estimated for non-core) and transportation rates (separately) by customer class. Approved or otherwise anticipated future increases in transportation rates.

---

19 For an introduction on the difference between core and non-core customers and why it matters in this context, see page 26.

16. Most recent annual GHG emissions from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator.
17. Most recent annual emissions of each criteria pollutant from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator.
18. Current number and classifications of full-time gas utility employees and estimated FTEs of contractor employees.

Objective D | *The Joint Agencies Adopt Gas Planning Scenarios to Analyze in the GRIP Process*

The final element of Step 1 would be for the Joint Agencies, through a public process at the CPUC, to develop a finite set of scenarios for further analysis in Steps 2 through 4. Scenario planning is particularly appropriate in this context, given a highly uncertain future, a broad range of potential solutions, and the likely availability of more information over time. This type of analysis will help to determine data gaps, pilot opportunities, and general policy direction that the agencies could use to move toward achievement of the state's GHG goals. In future iterations, the range of scenarios considered may narrow as the benefits and costs of potential solutions become clearer.

Scenario analysis would enable the GRIP to consider high, medium, and low gaseous fuel demand futures aligned with state policy goals to determine the least cost, least risk pathway to a decarbonized gas system. Three such possible scenarios were recently analyzed in detail in a report prepared for CARB by the consulting firm Energy + Environmental Economics (E3) and are excerpted in Appendix 3. The Joint Agencies would ultimately determine the number and characteristics of scenarios based on stakeholder input. **All scenarios would be designed to meet the State's 2030 and 2045 GHG emission reduction targets and goals, at a minimum.** The scenarios should include a sensitivity case where building electrification occurs somewhat randomly throughout the state, and another in which building electrification is targeted to specific locations (e.g., where all-electric reach codes have been adopted). It will be important that these scenarios are clearly specified, to avoid controversy as analytical work progresses in later steps of the GRIP process.

RECOMMENDED PROCESS FOR TRACK 1 IN THE INAUGURAL GRIP

All of the tasks described above as Objectives A-D could reasonably be grouped together into a "Track 1" of the GRIP process. Gridworks recommends that the Joint Agencies initiate the GRIP process with an en banc hearing that brings together the principals from the Joint Agencies to set expectations and goals for this new planning initiative. The hearing would include:

1. Staff presentations on the legislative and regulatory requirements binding the GRIP process;
2. Stakeholder presentations on recommended policy objectives and evaluation criteria; and
3. Staff or consultant presentations on the analytical basis for scenario development.

The hearing may also include high-level presentations from gas utilities on their gas system operations and foreseeable investments (i.e., information supporting achievement of Objectives B and C); this material might also be presented at a subsequent workshop. This information should be consistent with, but may be less certain than, investment requests made in general rate cases.

The CPUC could, by ruling, direct the gas utilities to begin the work described above, particularly for Objectives B and C, even before Phase 1 of the current Gas OIR has concluded. Following the en banc, at least two workshops would likely be required for utility presentations relating to Objectives B and C and for parties to ask questions and discuss planning scenario characteristics and assumptions. Following the conclusion of the workshops, the parties could be given a month for opening comments and two weeks for replies, presenting their own proposed guiding policy objectives, GRIP evaluation criteria, and their preferred scenario descriptions, as well as any information they wish to add to the record regarding Objectives B and C. The utilities' comments would include their respective final reports on current gas demand, system operations, and planned investments to achieve Objectives B and C, if these data are not already within the record of the proceeding.

The CPUC would then issue a Track 1 decision, identifying the governing legislative and statutory requirements, adopting its guiding policy objectives and plan evaluation criteria, and establishing a set of adopted scenario descriptions. This track should be able to be completed in four to six months from the date of the en banc.

STEP 2 FORECASTING OF SCENARIO GAS DEMAND AND SUPPLY

FIGURE 6. *GRIP Step 2 Outcome and Outputs*

OUTCOME	DATA OUTPUTS
Joint Agencies and Utilities collaboratively develop future forecasts of gas demand and supply under each of the adopted planning scenarios	• Forecasted demand under each scenario by customer class • Geographical representation of peak demand • Customers under each rate schedule • Forecasted deliveries of alternative gasesous fuels

The objective for Step 2 would be for the Joint Agencies and the utilities to collaboratively develop future forecasts of gas demand and supply under each of the adopted planning scenarios. Gridworks recommends that demand forecasting occur through an ongoing working group process, akin to the Demand Analysis Working Group for electric demand.[20] However, formation and convening of the working group should not delay the inaugural GRIP process.

DEMAND FORECASTING PROCESS

The CEC's end use gas demand forecasting models should be used to develop the system-wide base case forecast for residential and commercial building demand, making use of the most recent Residential Appliance Saturation Study (RASS) results. The amount and pace of fuel substitution (electricity for gas) would be determined separately for each scenario, based on the assumptions applicable to each of them.[21] More localized peak demand forecasts will also be needed, likely developed by the utilities, in order to determine specific infrastructure requirements on a more granular basis.

The Joint Agencies should consider establishing an ongoing working group for stakeholders to collaboratively determine future gas demand under the various scenarios. In addition to developing scenario forecasts, the working group could review different sensitivity cases for each scenario, using different assumptions about the pace of technology developments, the locational concentration or dispersion of all-electric buildings, and the future of gas and electric retail rates. New modeling tools may be necessary and the Joint Agencies and utilities will understandably need time to develop the skills and expertise needed to prepare more detailed demand forecasts. The scope of the working group may need to be refined as more experience is gained and modeling tools and capabilities are further developed.

20 Refer to the CEC's Demand Analysis Working Group website: https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/demand-analysis-working-group-dawg

21 The CEC has been sponsoring the development of a model known as the Fuel Substitution Scenario Analysis Tool in Docket 19-DECARB-01 that may be leveraged in scenario demand forecasting.

Currently the CEC's gas demand forecasts are not relied upon by other agencies to the same degree that the electric demand forecasts are used by the CPUC and CAISO for electric resource planning. We recommend that this situation be changed, such that the CEC's gas demand forecasts prepared by the Demand Analysis Office (for all customer classes except electric generation) are treated as the state's "official" system-wide forecast, similar to the electric demand forecast. The forecasts of gas demand for electric generation could be based on the adopted resource portfolios from the CPUC's Integrated Resource Planning (IRP) process for the electric utility service areas, supplemented with electric generation gas demand forecasts from the publicly-owned utilities. Alternatively, the electric generation gas demand forecasts resulting from the statewide SB 100 modeling work currently being conducted by a multi-agency task force might be employed once that process has been completed.

The existing CEC forecast of future gas commodity prices would be used as the starting point for demand forecasting, supplemented by forecasts of biomethane/renewable natural gas, green hydrogen, and synthetic natural gas prices as those fuels potentially enter the gas supply mix in greater volumes under the various scenarios.

There will also need to be a feedback loop that takes into account the impacts of the various assumed scenarios on future gas rates — which would be an output of the analysis — and possibly multiple iterations of the analysis until the input and output prices reach convergence. The use of a realistic forecast of future gas transportation rates is essential, as different throughput scenarios will have major impacts on future gas rates. The existing CEC IEPR gas demand forecast is plainly inadequate in this regard, as it incorrectly assumes very limited future escalation in the state's gas transportation rates. One or more of the sensitivities could also consider more widespread deployment of district heating and cooling as a technology alternative.

SUPPLY FORECASTING PROCESS

A critical component of the GRIP will be to identify the decarbonized fuel sources that are expected to supplement or replace fossil gas over time. The technological advancement of each of these fuel options should be carefully considered to determine the least cost, least risk pathway to decarbonization. Each of the adopted scenarios will include an expected portfolio of decarbonized fuel options, which will need to be updated for future iterations of the GRIP.

Appendix 4 summarizes some of the decarbonized fuel options that should be included in the GRIP analysis. The Appendix presents some of the opportunities, challenges, and costs of each fuel option, based on an initial limited literature review by Gridworks staff. The completion of this inventory should be one task for Joint Agency staff in the inaugural GRIP process. The inventory may serve as a foundation for the utilities' development of their future supply forecast.

Depending on each utility's strategies, the future fuel supply forecast could include estimates of:

1. Available supply and cost of biomethane to the utility's customers for each of the years 2025, 2030, 2035, 2040 and 2045.
2. Available supply and cost of green hydrogen to the utility's customers for each of the years 2025, 2030, 2035, 2040 and 2045.
3. Available supply and cost of synthetic natural gas to the utility's customers for each of the years 2025, 2030, 2035, 2040 and 2045.
4. Cost of installing carbon capture on a 500 MW electric generating facility in each of the years 2025, 2030, 2035, 2040 and 2045.

The data outputs from Step 2 should include, at a minimum:

1. Forecasted gas demand under each of the scenarios through at least 2035 and ideally through 2045, broken down by customer class and end use to the greatest extent feasible. Separate forecasts for average temperature and hydro year, 1 in 10 cold and dry year, 1 in 35 cold and dry year, and extreme peak day. Quantification of any expected curtailments under each set of conditions.
2. Under each scenario for the years 2025, 2030, 2035, 2040, and 2045, a geographic representation of peak gas demand, by city, county, company division, or other relevant geographic indicator.
3. Forecasted number of customers under each of the scenarios for each rate schedule and in total, at least through 2035 and ideally through 2045.
4. For each of the adopted scenarios, forecasted deliveries of alternative gaseous fuels, by type of fuel and by customer class (if known) for each year through 2035 and if possible 2045.

STEP 3 Define Future Infrastructure Needs and Cost Containment Strategies

FIGURE 7. GRIP Step 3 Outcomes and Outputs

OUTCOMES	DATA OUTPUTS
Utilities propose investments for future infrastructure needs and develop initial strategies for reducing future infrastructure investments and revenue requirements in order to avoid end user rate escalation and stranded costs	• Expected new capital additions • Forecasted Gas Rates • Forecasted emissions • Avoidable costs and recommended ratemaking changes to avoid rate escalation • Potential Impacts to Workforce and related mitigation strategies • Potential Impacts to Low-income and Disadvantaged Communities and related mitigation strategies

The objective for Step 3 would be for utilities to develop initial strategies for Joint Agency review and approval for reducing future infrastructure investments and revenue requirements as system throughput declines in order to avoid end user rate escalation and stranded costs. Each utility would be directed to assess its future infrastructure needs under each scenario including anticipated safety and compliance investments, investments required to serve any new customers, and any required system upgrades necessary to meet the scenario-specific demand forecast. Each utility would also propose actions to reduce revenue requirements, potentially by some percentage relative to the decline in throughput (e.g., for a 10% decline in throughput, reduce revenue requirements by 5%). For this GRIP component, the gas utilities would provide an infrastructure plan for each scenario that results in a safe and reliable gas system and, at a minimum:

- Quantifies the estimated rate impacts resulting from the proposed infrastructure investments;
- Identifies the financial mechanisms employed to minimize rate impacts (e.g., accelerated depreciation, securitization, shareholder-funded investments, public subsidies);
- Provides a description of the any workforce issues that arise from the plan (e.g., jobs lost/gained, jobs relocated) and proposed mitigation methods;
- Provides a description of any environmental justice issues that arise from the plan (e.g., increased energy burden, changes in localized criteria pollutant emissions, lack of access to energy resources) and proposed mitigation methods;
- Identifies any legal or regulatory barriers to reducing revenue requirement; and
- Quantifies the cost savings that would result if legal or regulatory barriers were removed.

This assessment will serve as the foundation for determining how to reduce system costs as throughput declines under each scenario in order to avoid rapidly escalating gas transportation rates, particularly for low-income customers. Such measures could include taking steps to convert end users in certain neighborhoods to all-electric service[22] in order to downrate certain local transmission lines to distribution pressure, reduce the need to upgrade or replace pressure regulators or valves, or avoid replacement of Aldyl-A pipe in certain neighborhoods.

This GRIP section should also propose pilot projects that will help to reduce revenue requirements. Pilot projects need to be undertaken, especially in disadvantaged communities, to target decommissioning segments of the gas distribution grid and transitioning buildings within that segment to all-electric service.[23] Such pilot projects should look to maximize avoided gas delivery system investments and minimize the costs of conversion to all-electric buildings. These types of pilots will help to determine which approaches might be most successful for reducing revenue requirements in the future, with the results of those pilots feeding into future iterations of the GRIP.

The data outputs from Step 3 should include, at a minimum:

1. Estimate of expected new or replacement annual capital additions for each of the next ten years under each of the adopted scenarios, broken down by utility function and by purpose (e.g., safety and compliance, any new customer connections, locational load growth, etc.), with appropriate adjustments for the scenario being analyzed. The expected useful life of any new or replacement assets given the scenario-specific demand forecast.

2. Forecasted Gas Rates including:
   a. Forecasted base margin (transportation revenue requirement) under each scenario for each of the years 2025, 2030, 2035, 2040 and 2045
   b. Cost of gas commodity and transportation rates (separately) by class under each scenario for each of the years 2025, 2030, 2035, 2040 and 2045.
   c. Estimated average gas bill increases, including identification of any annual bill increases that exceed the Consumer Price Index annual adjustment.

3. For each of the scenarios, an estimate of the system costs that could be avoided as a result of reduced demand, either system-wide or in particular local areas, and the timing of those cost savings, and whether they depend on changes in law, regulation, or incentive availability.

4. Ratemaking recommendations to avoid future end user escalation, such as accelerated depreciation, securitization, cost allocation changes, public subsidies, etc.

5. Forecasted Emissions under Each Scenario including:
   a. Annual GHG emissions from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator for each of the years 2025, 2030, 2035, 2040 and 2045.
   b. Annual emissions of each criteria pollutant from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator for each of the years 2030, 2035, 2040 and 2045. Criteria pollutant

22 Gridworks anticipates that a Targeted Electrification Framework is needed as a related policy initiative to assess electric alternatives to gas system investment and evaluate their impacts on California's climate goals, rates, equity, and a just transition for workers. However, the creation of such a framework is beyond the scope of a gas system planning process.

23 The CEC's funding opportunity GFO-20-503 is expected to result in "a set of guidelines and criteria that enable decision makers to easily identify potential project sites for natural gas system decommissioning, quantify the avoided natural gas infrastructure costs associated with all-electric service, assess costs of electric system upgrades and building electrification, and evaluate expected cost savings and customer acceptance" (https://www.energy.ca.gov/solicitations/2020-12/gfo-20-503-strategic-pathways-and-analytics-tactical-decommissioning-portions). These research results will provide further insight into how Step 3 is conducted in the future. Research results are expected in mid-2023 though interim workshops may help to inform the GRIP process prior to 2023.

emissions in disadvantaged communities for each of the years 2025, 2030, 2035, 2040 and 2045.

6. Potential Impacts to the Gas Workforce of Each Scenario and Strategies to Minimize those Impacts
   a. Any forecasted changes to the numbers and classifications of full-time utility employees and FTEs of contract employees by each of the years 2025, 2030, 2035, 2040 and 2045.
   b. The number (if any) of full-time utility employees estimated to be eliminated due to lack of sufficient work by each of the years 2025, 2030, 2035, 2040 and 2045.
   c. Strategies to retain the skilled workforce needed to provide safe and reliable service, along with mitigation measures to ensure that current gas utility employees are not adversely affected by the transition. For represented employees, these strategies and mitigation measures should be primarily informed by the results of collective bargaining between the gas utilities and the unions representing those employees.
   d. For each of the years 2025, 2030, 2035, 2040 and 2045, the number of new jobs estimated to have been created for the production of alternative gaseous fuels and/or the conversion of existing residential and commercial buildings from dual fuel to all-electric service, and/or any other new jobs created as a result of the scenario.
7. Potential Impacts to Low-income and Disadvantaged Communities from Each Scenario and Strategies to Minimize those Impacts, including:
   a. A narrative explanation of how proposed fuel supply, infrastructure plans, and forecasted rates would address existing harms in disadvantaged communities (e.g., improvements in local air quality, improvements in access to reliable energy service, bill protections).
   b. A narrative explanation of how proposed fuel supply and infrastructure plans would avoid future harm in disadvantaged communities (e.g., increased resilience in disadvantaged communities, sustained reductions in criteria air pollutants, opportunities for access to new technologies)

WHO DOES THE NECESSARY ANALYSIS?

Our stakeholders were divided in their opinions regarding who should perform the extensive analysis required to implement the GRIP. A number of participants would like to see the Joint Agencies (with consultant support) take the lead, similar to the process that has been followed thus far in the electric Integrated Resource Planning (IRP) proceeding. This view is driven by a concern that planning to reduce rate base and revenue requirements runs counter to a utility's fundamental profit motive. As such, relying on utility-led analysis may not lead to a productive result.

Others believe that the utilities are the only parties with enough detailed familiarity with the gas system, particularly at the distribution level, to be able to perform the required analyses in anything resembling a reasonable amount of time. Even with outside consulting help, the agencies currently lack sufficient staffing with granular knowledge of the utility systems to develop a plan on their own, particularly in the first iteration of the GRIP.

Based on our experience with Distribution Resource Planning for electricity, Gridworks is concerned that sufficient resources and funding can be assembled for the agencies to take on the entire suite of analyses required for the first iteration of the GRIP. While it may be possible for agency staff or outside consultants to perform *certain elements* of the analysis, such as emissions assessments or the evaluation of impacts on disadvantaged communities, the development of detailed plans for "system pruning" does not appear to be a good candidate for outsourcing, at least at this point in time. The CPUC may wish to consider providing some form of financial incentive for a utility that accepts the need for reducing gas system costs and offers constructive measures for achieving that result.

Ultimately this is a decision that only the agencies themselves can make. For the first iteration of the GRIP, that choice will need to be made in conjunction with the Track 1 decision, which will provide direction for the work to be undertaken in Steps 2, 3 and 4 of the process, which will comprise Track 2 of the GRIP.

c. Costs and benefits associated with changes in GHG and criteria pollutant levels in disadvantaged communities.

d. Economic burden on low-income ratepayers resulting from increasing gas rates and any mitigation measures proposed to reduce burden (e.g., bill protection, protecting against housing displacement).

Upon the completion of Step 3, the regulated gas utilities would file their Gas Resource and Infrastructure Plans, making proposals for near- and long-term gas resource and infrastructure investments and decarbonization strategies under each of the adopted scenarios. This would include utilities' proposed strategies to address the initial questions that drive future planning: which customers and end uses the system will serve over time and with which fuels, all while honoring the principles of safety, reliability, affordability, and equity, and meeting the state's GHG emission reduction goals.

STEP 4 Analyze and Evaluate the GRIP

FIGURE 8. *GRIP Step 4 Outcome and Outputs*

OUTCOME	DATA OUTPUTS
Joint Agencies, along with stakeholders, analyze the monetary and non-monteary costs and benefits of the various scenarios using the evaluation criteria adopted in Step 1	• Total Annual Societal Costs • Recommended Cost Mitigation Strategies • Analysis of proposed plans against adopted evaluation criteria

The objective of Step 4 is for the Joint Agencies, along with stakeholders, to analyze the costs and benefits, both monetary and non-monetary, of the various scenarios using the .evaluation criteria adopted in Step 1. Joint Agencies, potentially supported by outside consulting assistance, and stakeholders will need to rigorously review each utility's assessment of future gas infrastructure needs and costs under each of the adopted scenarios. The data outputs from the evaluation conducted in Step 4 should include:

1. Total annual societal monetary costs[24] for each scenario by 2045.

2. Total annual societal externality cost of each scenario by 2045, including

   a. Estimated average total cost of installing all-electric versus dual fuel service in new homes and new commercial businesses for each of the years 2025, 2030, 2035, 2040 and 2045, including any line extension allowance as part of that cost, and including a breakdown of primary cost components to the extent feasible; and

   b. Estimated average total cost of converting existing dual fuel service homes or commercial businesses to all-electric service for each of the years 2025, 2030, 2035, 2040 and 2045, shown with and without the cost of any required panel upgrades, and including a breakdown of primary cost components to the extent feasible.[25]

3. Recommended cost mitigation strategies to minimize and stabilize future rate increases.

4. Analysis of the proposed GRIPs against the evaluation criteria adopted in Step 1 and any mitigation measures necessary to align GRIPs with the evaluation criteria.

24 The term "societal" cost in this context is not intended to reference to "Societal Cost Test" for cost-effectiveness employed by the CPUC, or any of the other traditional cost-effectiveness tests. Rather, societal cost in this context refers to the overall cost of achieving the GHG reduction target, ignoring any transfer payments.

25 Previous studies have already attempted to analyze these societal costs and benefits of differing future scenarios, including: Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price, 2020. The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and *Public Health Benefits of Reducing Natural Gas Use*. California Energy Commission. Publication Number: CEC-500-2019-055-F.

The *distribution* of overall societal costs and benefits among different interest groups will be an important consideration, regardless of the overall societal cost-benefit outcome. If a particular scenario produces a more favorable overall societal cost-benefit ratio but imposes undue burdens on a specific group or set of interests, then mitigations would need to be included to address resulting inequities. Further, good long-term planning to control the speed and shape of any decline in the utility workforce will be essential to mitigate worker displacement, and the plan should incorporate the costs of ensuring a just transition for any displaced workers, consistent with collective bargaining agreements.

To support pilot development, the CEC should conduct a study of the barriers to electrification for low-income and disadvantaged communities, with a focus on rental, multi-family, and existing homes. The study should provide recommendations on ways to address those barriers and initiate pilot projects designed to determine the ways of reducing these barriers. Meaningful stakeholder engagement[26] is critical to designing pilots that benefit communities. Lessons learned from the San Joaquin Valley Affordable Energy Proceeding (A.15-03-010) should be examined in that process.[27, 28]

To prepare these analyses, new tools may be necessary, some of which may not be familiar to the CPUC but may be available through the CEC, CARB, or other outside consultants. For instance, a rate impact analysis tool would be needed to estimate changes in gas rates over time under the various proposed solutions.[29] More specifically, future gas transportation rate increases may be more moderate if slower building electrification is assumed in a particular scenario, but progressively larger as more load shifts from the gas system to the electric system.

RECOMMENDED PROCESS FOR TRACK 2 OF THE GRIP

All of the tasks described above in Steps 2-4 would be grouped together into a "Track 2" of the GRIP process. The extensive analysis required will take considerable time, likely six to nine months, particularly in the first iteration. Periodic workshops should be conducted on a regular basis to track the progress of the work and obtain input from stakeholders. Track 2 will likely require full evidentiary hearings, with associated discovery, prepared testimony, hearings and briefing. This would likely require an additional eight to ten months, but still allow the entire process to be completed in about two years. Future iterations of the GRIP could reasonably be expected to take less time in total, but are still likely to require about 18 months.

To encourage transparency in the analysis and evaluation process, the Joint Agencies or their consultants would present their analyses of the adopted scenarios with respect to each of the multiple adopted evaluation criteria and make related recommendations regarding long-term gas resource and infrastructure investments and decarbonization strategies. Other parties could present their own analyses and recommendations as well. The goal would be to understand which scenario, or combination of scenarios, best addresses the adopted evaluation criteria. The answers to these questions may require multiple iterations of process, with feedback from pilot projects initiated in earlier cycles and additional research helping to inform future cycles.

26 Meaningful stakeholder engagement includes, at a minimum, outreach and education in multiple languages and coordination with community-based organizations.

27 Challenges faced in the San Joaquin Valley pilots include: (1) unplanned reliance on community-based organizations to engage with customers; (2) lack of adequate resources to educate and engage with communities; (3) use of Census Designated Places as boundaries for pilot communities; and (4) administrative burden of reporting requirements and unclear guidance. See "Pilot Team Notification of *Ex Parte* Communications, filed October 7, 2020, for a description of challenges faced in the San Joaquin Valley Disadvantaged Communities Pilot. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M351/K622/351622380.PDF.

28 Evergreen Economics is developing a process evaluation for the San Joaquin Valley Disadvantaged Communities Pilots. Refer to SJV DAC Pilot Projects Process Evaluation for more information on the research plan: https://pda.energydataweb.com/api/view/2432/SJV%20DAC%20Final%20Research%20Plan%20101220.pdf. The results of this evaluation should inform ongoing efforts to engage disadvantaged communities.

29 In the analysis for *The Challenge with Retail Gas in a Low-Carbon Future*, cited above, E3 developed a gas rate impact tool that could be employed here, or else a similar model could be utilized.

STEP 5 Issue a Commission Decision

FIGURE 9. *GRIP Step 5 Outcome*

OUTCOME
The CPUC incorporates stakeholder input into a Commission Decision that approves and directs gas system decarbonization strategies

Once the utilities' proposed Gas Resource and Infrastructure Plans are submitted and evaluated, the CPUC would incorporate stakeholder input into a Commission decision that approves gas system decarbonization strategies. The ultimate decision would determine the decarbonization strategy California would follow for the gas delivery system, while also maintaining the safety, reliability, affordability, and equity evaluation criteria adopted by the CPUC in the Track 1 decision.

The Commission's Track 2 decision would address each of the legal requirements, policy drivers, and evaluation criteria previously adopted in the Track 1 decision and adopt a GRIP for the state or for each utility. The Commission should also consider "least regrets" near-term policy actions to mitigate future stranded costs, such as all-electric construction in the ongoing conversions of mobile home parks to direct utility service, or potential changes to the gas line extension rules to discourage further growth of the gas distribution system.

The decision would adopt pilots, programs, and/or policies to achieve each of identified policy goals, and direct utilities to file applications as needed to comply with that guidance. The decision could also direct activities in other gas-related proceedings, such as gas utility general rate cases or other one-off proceedings. Lastly, the decision might also recommend changes in law and regulations, or actions by other agencies, that are needed to ensure that reasonable rates are maintained for the remaining gas customers over time.

The inaugural GRIP evaluation and resulting CPUC decision need to establish a clear pathway for implementing financial mechanisms to manage the costs of the gas transition, including updating depreciation schedules, aligning shareholder interests with non-pipeline alternatives, and securitization of remaining asset value. These approaches are expected to be updated over time and different approaches may be warranted for existing versus future assets.

For existing gas system assets, the financial treatment of asset book values might seek to recover costs in a more expedited manner, leveraging tools such as accelerated depreciation, securitization of gas assets, and changes to cost allocation.[30] For future gas system investments, the financial treatment of the asset value should seek to minimize stranded asset risk for utility shareholders and ratepayers. This might be done by ensuring that the assumptions used in the "used and useful" determination (e.g., expected useful life of the asset) align with carbon neutrality policies.[31]

Development of, and recommendations from, the GRIP may catalyze regulatory reform activities in other proceedings, including General Rate Cases and the Triennial Cost Allocation Proceeding (TCAP) at the CPUC. The CPUC could direct the gas utilities to initiate a short-term (three to six months) collaborative working group process to update gas rate design and cost allocation to minimize and stabilize gas rate increases. At the conclusion of the working group process, all participating parties would propose modifications to gas rate design and cost allocation for the CPUC's consideration.

In future GRIP cycles, the Commission will want to monitor progress and adopt course corrections as necessary to increase the benefits and mitigate the costs of its chosen set of strategies, or perhaps even revise those strategies. In addition, the future gas rates produced in one iteration of the GRIP should be incorporated into the assumptions used in the demand forecasts for the next iteration of the process. Depending upon the strategies for GHG reduction that the Commission ultimately chooses, future rounds of the GRIP process may emphasize different types of issues, but the overall framework presented here can be followed in any case.

30 Gridworks, *California's Gas System in Transition: Equitable, Affordable, Decarbonized, and Smaller*, page 13-15, September 2019, https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.
31 See Environmental Defense Fund's report *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California*: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

COMPLEXITIES IN GAS PLANNING

Gridworks recognizes that distilling the transition to a decarbonized gas system into a five-step recurring planning process may be overly simplistic, overly complicated, or both. California's gas system is complex and all stakeholders, including Joint Agencies, have a lot to learn about how to plan for future system operations and management. We note the following complexities to highlight the unique considerations and context within which the GRIP will operate.

CORE AND NON-CORE CUSTOMERS

It is important to recognize that gas differs from electricity in that, under the core/non-core structure in place since the late 1980s, the procurement of the fuel (commodity) to serve large non-core customer gas demands is effectively deregulated, with virtually no CPUC oversight.

The gas utilities transport the fuel to the non-core end user's location but have no role in what is bought and sold, other than tariffed quality specifications for what can be injected into the pipeline. Unlike the Renewables Portfolio Standard (RPS) and Resource Adequacy (RA) requirements that apply to all load serving entities with customers on the electric utility's system, there are no comparable statutory provisions that govern retail sellers of the gas commodity to non-core end users.

Gas end use facilities with annual emissions exceeding 25,000 metric tons of CO_2e (i.e., "covered entities"), such as electric power plants and large industrial plants, are subject to the state's Cap and Trade program and must obtain allowances. Other gas end users that are not covered entities pay for cap-and-trade allowances through their utility rates. This again differs from electricity because it is the combustion of fossil gas by the customer that produces emissions, rather than the generation of the electricity that the utility delivers to the ultimate consumers. The gas utilities provide bundled commodity and transportation services to core end users, unless the customer chooses to purchase its supply from a Core Transport Agent under rules similar, but not identical, to those governing non-core transportation service. This fundamental difference in industry structure needs to be kept in mind as the state considers ways to decarbonize the gas system.

GEOGRAPHICAL DIFFERENCE IN GAS DEMAND

In recent years at least 40 cities and counties, mostly in Northern California, have established local mandates committing to limiting or banning fossil gas infrastructure in new construction.[32] At the same time, more than 120 local municipalities, mostly in Southern California, have passed non-binding resolutions calling for energy choices that include gaseous fuels, such as fossil gas, biomethane, and hydrogen.[33] The practical impact of these local mandates and resolutions is that they will result in greater geographical variance in gas demand across the state.

These local actions reflect an ongoing debate over the preferred method(s) to reduce GHG emissions from the gas sector. Stakeholders are divided with regard to whether electrification (i.e., converting fossil gas end uses to make use of decarbonized electricity), alternative gaseous fuels (e.g., biomethane, green hydrogen), or combinations of these technologies are or will be the least cost, least risk method(s) to decarbonize the energy sector. It is most likely that some combination of decarbonized electricity and alternative gaseous fuels will replace fossil gas, but the relative proportions and speed at which these changes will occur is difficult to predict (see Fuel Switching and Future Pipeline Fuels below).

32 Sierra Club, December 2020, California's Cities Lead the Way to a Gas-Free Future, Accessed December 8, 2020, at https://www.sierraclub.org/articles/2020/12/californias-cities-lead-way-gas-free-future

33 SoCalGas, Balanced Energy Resolutions website, Accessed October 6, 2020, https://www.socalgas.com/vision/balanced-energy-resolutions.

Given the difference in the political and institutional context between Northern and Southern California, gas utilities are expected to prefer very different approaches for managing the decarbonization of their respective gas delivery systems. State agencies and gas utilities will need to develop granular gas demand forecasts, potentially by geographic region, to better understand where infrastructure improvements are necessary and where infrastructure may be retired. This type of analytical capability may take multiple years to develop and refine and Joint Agencies and utilities should immediately start developing the skillsets, models, and tools required for more detailed demand forecast analyses.

FUEL SWITCHING AND FUTURE PIPELINE FUELS

A combination of decarbonized electricity and alternative gaseous fuels will replace fossil gas as California works toward our climate goals; however, the pace and relative proportions of each resource in replacing fossil gas are uncertain and difficult to forecast across diverse sectors. Numerous studies have identified decarbonized electricity as the least-cost, emissions-free, and readily-accessible resource to replace fossil gas.[34, 35, 36] Electricity, however, may not be able to adequately serve industrial end uses with high-heat applications (e.g., food processing, electric generation) and efficient electrified appliances (e.g., heat pump space and water heaters) still need to become cost competitive in retrofit scenarios.

Further, studies identify that alternative gaseous fuels will be limited in availability with relatively high costs.[37, 38] These fuels are likely to be prioritized to replace more emissions-intensive fuels, such as gasoline and diesel, or for high-heat industrial end uses. Without significant technological advancement, which cannot be guaranteed, alternative gaseous fuels are unlikely to be an affordable or accessible resource for broad use in the residential and small commercial sectors.

This report, however, is not intended to settle the debate over the "right" future resource mix. Rather, we note that the high degree of uncertainty related to the future fuel mix emphasizes the importance of a robust long-term gas planning process. This report outlines the structure of a process whereby public agencies and interested stakeholders can gather, analyze, and evaluate data on the potential energy sources and infrastructure needed to provide the services currently provided by the gas delivery system and the fuels contained therein, *consistent with the state's GHG reduction policy*.

CONCLUSION

This report is intended to assist the Joint Agencies in planning for and structuring a long-term planning process strategy to manage the state's transition away from fossil gas toward a decarbonized energy future. We urge leaders throughout California to leverage the content herein to accelerate the next phase of the CPUC's current proceeding R.20-01-007.

34 E3, June 2018, Deep Decarbonization in a High Renewables Future, page 3. https:// ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf
35 Rocky Mountain Institute, December 2019, The Impact of Fossil Fuel in Buildings, https://rmi.org/fossil-gas-has-no-future-in-low-carbon-buildings/.
36 E3, April 2020, The Challenge of Retail Gas in California's Low Carbon Future, https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.
37 Energy Future Initiative, May 2019, Optionality, Flexibility, and Innovation: Pathways for Deep Decarbonization in California, pages 179-180, 220-222.
38 American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, prepared by ICF International, December 2019; https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf. The ICF report estimates potential RNG supplies nationally of 1.9 to 4.5 quadrillion BTUs (quads) in 2040 (page 2), at prices ranging from $7 to $45 per MMBtu (page 5). This compares to total U.S. fossil gas usage of over 30 quads in 2019, as reported by the U.S. Energy Information Administration.

APPENDIX 1

GAS PLANNING OBJECTIVES AND DATA REQUIREMENTS

STEP 1 Establish Policy Goals, Evaluation Criteria, Planning Scenarios, and a Baseline Assessment of Current System Demand and Infrastructure

Objectives

A. The Joint Agencies identify legislative and statutory requirements and adopt guiding policy objectives and evaluation criteria to be used to evaluate filed Gas Resource and Infrastructure Plans;

B. Regulated gas utilities report on current gas demand;

C. Regulated gas utilities present concise descriptions of their current gas systems and currently approved or planned changes to those systems, including key operational considerations; and

D. The Joint Agencies, through a public process at the CPUC, adopt gas planning scenarios to analyze in the GRIP process.

Data Requirements

1. Recorded average and peak day gas demand for the most recent five years.
2. A geographic representation of current average and peak day gas demand, by city, county, company division or other relevant geographic indicator (as available), including expected impacts of local government decarbonization initiatives.
3. Number of customers for each rate schedule and in total, for the most recent recorded year, broken down by core and non-core.
4. Numbers of core and non-core customers, by class, served directly from: backbone transmission, local transmission, or distribution. Number of distinct distribution systems across the service area and percentage of those that include at least one non-core customer.
5. Geographic representation of the locations of current non-core customers by city, county, company division or other geographic indicator (as available), including service level (backbone, local transmission, or distribution).
6. Current (end of last calendar year) Net Book Value of Assets by function, including backbone transmission, local transmission, storage, distribution, customer-related (if separate from distribution), and other (including relevant components by category).
7. Projected end of year net book value of assets by category, assuming no additional investment, for each year until all assets are fully depreciated at existing depreciation rates.
8. Percentage utilization of system capacity on a peak day, disaggregated by functional components and geographical location to the extent possible.
9. Estimate of expected annual capital additions for each of the next ten years, broken down by function and by purpose (e.g., safety and compliance, new customer connections, load growth, etc.).
10. Leaks:
    a. Number of leaks discovered per year for the last five years.
    b. Number of leaks repaired per year for the last five years.

c. Estimated gas losses due to leaks for the last five years.

d. Total lost and unaccounted for (LUAF) gas for the last five years.

11. Estimated miles of Aldyl-A pipe in the system that will need to be replaced over the next ten years.
12. Gas supply by source (producing basin or delivery pipeline) for the most current recorded year and any expected changes over the next five years.
13. Most recent recorded year's deliveries of alternative gaseous fuels (other than fossil gas), by type and source of fuel and by customer class if available. Expected changes over the next 10 years.
14. Current total base margin (transportation revenue requirement).
15. Current cost of commodity (estimated for non-core) and transportation rates (separately) by customer class. Approved or otherwise anticipated future increases in transportation rates.
16. Most recent annual GHG emissions from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator.
17. Most recent annual emissions of each criteria pollutant from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator.
18. Current number and classifications of full-time gas utility employees and estimated FTEs of contractor employees.

STEP 2 Forecasting of Scenario Gas Demand and Supply

Objective

Joint Agencies and the utilities to collaboratively develop future forecasts of gas demand and supply under each of the adopted planning scenarios

Data Requirements

1. Forecasted gas demand under each of the adopted scenarios through at least 2035 and ideally through 2045, broken down by customer class and end use to the greatest extent feasible. Separate forecasts for average temperature and hydro year, 1 in 10 cold and dry year, 1 in 35 cold and dry year, and extreme peak day. Quantification of any expected curtailments under each set of conditions.
2. Under each scenario for the years 2025, 2030, 2035, 2040, and 2045, a geographic representation of peak gas demand, by city, county, company division, or other relevant geographic indicator.
3. Forecasted number of customers under each of the adopted scenarios for each rate schedule and in total, at least through 2035 and ideally through 2045.
4. For each of the adopted scenarios, forecasted deliveries of alternative gaseous fuels, by type of fuel and by customer class (if known) for each year through 2035 and if possible 2045.

STEP 3 Define Future Infrastructure Needs and Cost Containment Strategies

Objective

Utilities develop initial strategies for Joint Agency review and approval for reducing future infrastructure investments and revenue requirements as system throughput declines in order to avoid end user rate escalation and stranded costs.

Data Requirements

1. Estimate of expected new or replacement annual capital additions for each of the next ten years under each of the adopted scenarios, broken down by utility function and by purpose (e.g., safety and compliance, any new customer connections, locational load growth, etc.), with appropriate adjustments for the scenario being analyzed. The expected useful life of any new or replacement assets given the scenario-specific demand forecast.
2. Forecasted Gas Rates including:
3. Forecasted base margin (transportation revenue requirement) under each scenario for each of the years 2025, 2030, 2035, 2040 and 2045
4. Cost of gas commodity and transportation rates (separately) by class under each scenario for each of the years 2025, 2030, 2035, 2040 and 2045.
5. Estimated average gas bill increases, including identification of any annual bill increases that exceed the Consumer Price Index annual adjustment.
6. For each of the scenarios, an estimate of the system costs that could be avoided as a result of reduced demand, either system-wide or in particular local areas, and the timing of those cost savings, and whether they depend on changes in law, regulation, or incentive availability.
7. Ratemaking recommendations to avoid future end user escalation, such as accelerated depreciation, securitization, cost allocation changes, public subsidies, etc.
8. Forecasted Emissions under Each Scenario including:
    a. Annual GHG emissions from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator for each of the years 2025, 2030, 2035, 2040 and 2045.
    b. Annual emissions of each criteria pollutant from the combustion of utility-delivered gas for the entire service area and broken down by customer class and by city, county, company division, or other geographic indicator for each of the years 2030, 2035, 2040 and 2045. Criteria pollutant emissions in designated Disadvantaged Communities for each of the years 2025, 2030, 2035, 2040 and 2045.
9. Potential Impacts to the Gas Workforce under Each Scenario and Strategies to Minimize those Impacts
    a. Any forecasted changes to the numbers and classifications of full-time utility employees and FTEs of contract employees by each of the years 2025, 2030, 2035, 2040 and 2045.
    b. The number (if any) of full-time utility employees estimated to be eliminated due to lack of sufficient work by each of the years 2025, 2030, 2035, 2040 and 2045.
    c. Strategies to retain the skilled workforce needed to provide safe and reliable service, along with mitigation measures to ensure that current gas utility employees are not adversely affected by the transition. For represented employees, these strategies and mitigation measures should be primarily informed by the results of collective bargaining between the gas utilities and the unions representing those employees.

d. For each of the years 2025, 2030, 2035, 2040 and 2045, the number of new jobs estimated to have been created for the production of alternative gaseous fuels and/or the conversion of existing residential and commercial buildings from dual fuel to all-electric service, and/or any other new jobs created as a result of the scenario.

10. Potential Impacts to Low-income and Disadvantaged Communities from Each Scenario

a. A narrative explanation of how proposed fuel supply, infrastructure plans, and forecasted rates would address existing harms in disadvantaged communities (e.g., improvements in local air quality, improvements in access to reliable energy service, bill protections).

b. A narrative explanation of how proposed fuel supply and infrastructure plans would avoid future harm in disadvantaged communities (e.g., increased resilience in disadvantaged communities, sustained reductions in criteria air pollutants, opportunities for access to new technologies)

c. Costs and benefits associated with changes in GHG and criteria pollutant levels in disadvantaged communities.

d. Economic burden on low-income ratepayers resulting from increasing gas rates and any mitigation measures proposed to reduce burden (e.g., bill protection, protecting against housing displacement).

STEP 4 Analyze and Evaluate the GRIP

Objective

Joint Agencies, along with stakeholders, analyze the costs and benefits, both monetary and non-monetary, of the various scenarios using the evaluation criteria adopted in Step 1.

Data Requirements

1. Total annual societal monetary costs39 for each scenario by 2045.
2. Total annual societal externality cost of each scenario by 2045, including

a. Estimated average total cost of installing all-electric versus dual fuel service in new homes and new commercial businesses for each of the years 2025, 2030, 2035, 2040 and 2045, including any line extension allowance as part of that cost, and including a breakdown of primary cost components to the extent feasible.

b. Estimated average total cost of converting existing dual fuel service homes or commercial businesses to all-electric service for each of the years 2025, 2030, 2035, 2040 and 2045, shown with and without the cost of any required panel upgrades, and including a breakdown of primary cost components to the extent feasible.

Recommended cost mitigation strategies to minimize and stabilize future rate increases.

Analysis of the proposed GRIPs against the evaluation criteria adopted in Step 1 and any mitigation measures necessary to align GRIPs with the evaluation criteria.

39 The term “societal” cost in this context is not intended to reference to “Societal Cost Test” for cost-effectiveness employed by the CPUC, or any of the other traditional cost-effectiveness tests. Rather, societal cost in this context refers to the overall cost of achieving the GHG reduction target, ignoring any transfer payments.

STEP 5 Issue a Commission Decision

Objective

Incorporate stakeholder input into a Commission decision that approves gas system decarbonization strategies

Data Requirements

See above

APPENDIX 2

STATEWIDE STATUTES AND REGULATIONS AFFECTING GAS PLANNING

Statutes and Regulations	Requirements in Relation to Climate and Gas Planning
SB32 (2006, Pavley)	Requires the state to reduce GHG emissions to 40% below 1990 levels by 2030
SB1371 (2014, Leno)	Requires regulated gas corporations to establish best practices for leak management in their gas distribution system
AB 2672 (2014, Perea)	Requires options to increase access to affordable energy in disadvantaged communities
SB 350 (2015, De Leon)	Requires a doubling of energy efficiency in electric and gas end uses by 2030, including specific strategies for overcoming barriers to clean energy access in disadvantaged communities
AB 1383 (2016, Lara)	Requires the CARB to implement a short-lived climate pollutant strategy to reduce statewide methane emissions to 40% below 2013 levels by 2030
AB 523 (2017, Reyes)	Requires Electric Program Investment Charge (EPIC) research and pilots in and of benefit to disadvantaged communities
SB 100 (2018, De Leon)	Accelerates Renewable Portfolio Standards to 60% by 2030 and requires that carbon-free resources supply 100% of retail sales of electricity by 2045
AB 3232 (2018, Friedman)	Requires the California Energy Commission (CEC), in consultation with the CPUC, CARB, and the California independent System Operator (CAISO) to assess the potential to reduce GHG emissions in residential and commercial buildings by at least 40% of 1990 levels by 2030
EO-B-55-18	Establishes the goal to achieve a carbon neutral economy by 2045
PU Code Sections 328-328.2	Requires gas corporations to continue to provide core customers with basic gas services (commonly referred to as the "Obligation to Serve")
PU Code Section 400(b)	Requires the CPUC and CEC to "[t]ake into account the opportunities to decrease costs and increase benefits, including pollution reduction and grid integration, using renewable and nonrenewable technologies with zero or lowest feasible emissions of greenhouse gases, criteria pollutants, and toxic air contaminants onsite in proceedings associated with meeting the objectives."
PU Code Section 451	Requires utilities to provide affordable, safe, and reliable electric and gas services at just and reasonable rates
PU Code Section 454.52(a)(1)(I)	Requires long-term energy resource planning to minimize GHG and air pollutants with an early priority to disadvantaged communities
PU Code Sections 454.55(a)(2) and 454.56(d)	Requires maximizing both gas and electric energy efficiency savings, including in disadvantaged communities

PU Code Section 651	Authorizes the CPUC to consider adopting biomethane procurement targets or goals if cost effective as a means of reducing emissions of short-lived climate pollutants and other GHGs
PU Code Section 701.1(a)(1)	Declares that a principal goal of gas utilities' resource planning and investment shall be to improve the environment
PU Code 740.8	Requires the creation of high-quality jobs or other economic benefits in disadvantaged communities
PU Code Sections 961(d)(10) and 977(a)	Require an adequately sized and properly trained gas corporation workforce
CPUC General Order 58-A: Standards of Gas Service	Establishes requirements for safe operations and utility/customer interconnection
CPUC General Order 58-B: Heating Value Measurement Standard for Gaseous Fuels	Provides requirements for heating value and the measurement of the heating value of gaseous fuels distributed by a utility for use to provide heat

APPENDIX 3

ILLUSTRATIVE POTENTIAL GAS DEMAND SCENARIOS

Excerpted from CARB E3 report entitled "Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board," dated October 2020, at page 21-24.

In this report, we evaluate three different scenarios that achieve carbon neutrality by 2045 (excluding sources from NWL), distinguished by their degree of reductions from fossil fuel-based greenhouse gas emissions versus CDR [Carbon Dioxide Removal] strategies, including land-based carbon sinks and NETs [Negative Emission Technology]. All of the scenarios achieve at least a 40% reduction in GHG emissions by 2030 and an 80% reduction in GHGs by 2045, relative to 1990 levels, without any reliance on CDR. The three scenarios are evaluated based on the potential costs, fuel combustion (used as a proxy for air quality-related health impacts), climate change mitigation risk and technology and implementation risk and feasibility of each scenario. A "reference" or "counterfactual" scenario is not evaluated in this study but will be an important focus of CARB's next Scoping Plan.

+ **The "High Carbon Dioxide Removal" scenario** includes a broad range of deep decarbonization strategies, which are similar to E3's prior "high electrification" scenario, including energy efficiency, electrification, low-carbon fuels, zero-carbon electricity, and reductions in non-energy GHG emissions. In addition, off-road transportation electrification is accelerated, and industrial carbon capture and sequestration (CCS) is assumed, in order to achieve just over 80% reductions in direct GHG emissions by 2045. In this scenario, 80 million metric tons (MMT) of CO_2e from fossil fuel combustion and non-energy GHGs in 2045 remain. These gross emissions net to zero by applying 80 MMT of carbon dioxide removal strategies, including sinks from natural and working lands and negative emissions technologies like direct air capture.

+ **The "Zero-Carbon Energy" scenario** includes a similar set of decarbonization strategies as the High CDR scenario, but these strategies are deployed earlier and more deeply. As a result, 2030 GHG emissions are lower in this scenario, achieving a 45% reduction in GHGs by 2030, relative to 1990 levels. In addition, emerging emission reduction technologies, including synthetic natural gas in the gas pipeline, electric aviation, and fuel-cell trains in off-road transportation are applied, in order to eliminate all fossil fuel emissions by 2045. In the zero-carbon energy scenario there are zero fossil fuel emissions by 2045. The remaining 33 MMT of CO_2e in 2045 in this scenario come from non-energy sources of GHGs, including methane from agriculture. These gross emissions are mitigated using CDR strategies to achieve carbon neutrality.

+ **The "Balanced" scenario** represents a balance between the measures in the High CDR scenario and the zero-carbon energy scenario, which each represent a bookend approach towards achieving carbon neutrality. The balanced scenario includes less reliance on CDR strategies, compared to the High CDR scenario, but also has less reliance on the more speculative emission reductions technologies included in the Zero-Carbon Energy scenario, like electric aviation and hydrogen fuel-cell trains. In addition, the pace of electrification is somewhat slower in the balanced scenario compared to the zero-carbon energy scenario. This scenario results in 56 MMT of CO_2e in 2045, about half of which is from fossil fuel emissions and half of which is from non-energy GHG emissions, which must be reduced with CDR strategies.

A summary of the key emission reduction strategies applied in each scenario are summarized in Table 1 below. More details about the sector-by-sector assumptions in each scenario are described in Section 2 below, including a discussion of the carbon mitigation strategies evaluated in each sector.

TABLE 1. *Summary of emission reduction strategies by scenario (measures that are the same across all scenarios are shown in grey font)*[40]

SECTOR	HIGH CDR SCENARIO	BALANCED SCENARIO	ZERO CARBON ENERGY SCENARIO
Low-Carbon Fuels	**0.4 Exajoules (EJ)** of **advanced biofuels** for: on & off-road ground transportation pipeline gas demand (12% biomethane) **0.1 EJ** of **hydrogen** for: pipeline gas demand (5% H_2 blend)	**0.4 EJ** of **advanced biofuels** for: on & off-road ground transportation renewable aviation fuel biomethane for electricity generation **0.3 EJ** of **hydrogen** for: pipeline gas demand (5% H_2 blend) direct H_2 combustion in industry (100% H_2 blend) HDV fuel cell transportation	**0.4 EJ** of **advanced biofuels** for: on & off-road ground tran. sportation renewable aviation fuel biomethane for electricity generation **0.3 EJ** of **hydrogen** for: pipeline gas demand (5% H_2 blend) direct H_2 combustion in industry (100% H_2 blend) HDV fuel cell transportation **0.04 EJ** of **synthetic natural gas** for: industry gas demand (10% blend)
Buildings	**100%** sales of electric appliances by **2040** High energy efficiency: • *SB 350 **doubling of AAEE** is met by 2030* • *46 TWh of e/ectrlc EE in 2030 relative to 2015* • *67 TWh of electric EE ,n 2045 relative to 2015*	**100%** sales of electric appliances by **2035** High energy efficiency: • *SB 350 doubllng of AAEE is met by 2030* • *46 TWh of e/ectrlc EE in 2030 relative to 2015* • *67 TWh of electtfc EE m 2045 relative to 2015*	**100%** sales of electric appliances by **2030** **All** gas end uses retired by 2045 High energy efficiency: • *SB 350 **doubling of AAEE** Is met by 2030* • *46 TWh of e/ec/ric EE in 2030 relative to 2015* • *67 TWh of e/ec/ric EE in 2045 elative to 2015*
Transportation	**100%** BEV sales for LDV by **2035** **100%** BEV sales for MDV by **2040** **45%/48%** BEV/CNG sales for HDV by **2035** **50%** rail electrification **No** aviation electrification	**100%** BEV sales for LDV by **2035** **100%** BEV sales for MDV by **2035** **45%/48%** BEV/HFCV sales of HDV by **2035** **75%** rail electrification **No** aviation electrification	**100%** BEV sales for LOV by **2030** **100%** BEV sales for MDV by **2030** **50%/50%** BEV/HFCV sales for HDV by **2035** **75%/25%** rail electrification/ hydrogen **50%** of in-state aviation electrified
Industry & Agriculture	**No** incremental industry electrification **No** direct hydrogen combustion **17 MMT** CCS for cement, glass, oil & gas **~80%** reduction in ag. energy emissions **90%** reduction in energy demand from oil & gas extraction and petroleum refining	**44%** of energy demand met with electricity **16%** of energy demand met with hydrogen **18 MMT** CCS for cement, glass, oil & gas **~90%** reduction in ag. energy emissions **90%** reduction in energy demand from oil & gas extraction and petroleum refining	**53%** of energy demand met with electricity 19% of energy demand met with hydrogen **14 MMT CCS** for cement and glass **100%** reduction in ag. energy emissions **100%** reduction in energy demand from oil & gas extraction and petroleum refining

40 Percentage hydrogen blend is given as a % of energy input. Prior E3 studies (Mahone, 2018) have evaluated up to 7% hydrogen blends as a percentage of energy input in some scenarios. An additional 2% increase in hydrogen blended into the gas pipeline should be technically feasible, but would not have a sub-stantial impact on the scenario results presented here.

Electricity	Remaining dispatchable gas capacity is fueled with **natural gas** **95%** zero carbon generation	Remaining dispatchable gas capacity is fueled with **biomethane (modeled) or hydrogen** **100%** zero carbon generation	Remaining dispatchable gas capacity is fueled with **biomethane (modeled) or hydrogen** **100%** zero carbon generation
High GWP & Non-Combustion	Emissions reductions relative to 2020: **23%** for landfill & wastewater methane; **72%** for pipeline fugitive methane; **41%** for agricultural methane/N_2O; **75%** for HFCs/refrigerants		Same as other scenarios, but with **100%** reduction in gas distribution pipeline fugitive methane due to gas distribution grid retirement
Carbon Dioxide Removal	**80 million metric tons/year** of carbon dioxide removal needed in 2045	**56 million metric tons/year** of carbon dioxide removal needed in 2045	**33 million metric tons/year** of carbon dioxide removal needed in 2045

APPENDIX 4

COMPARISON OF DIFFERENT FUEL TYPES

FUEL OPTION	DEFINITION	OPPORTUNITIES	CHALLENGES	COMMODITY COST
Fossil gas with Carbon Capture and Storage (CCS)	Carbon capture and storage (also referred as carbon capture and sequestration) is the process by which CO_2 from power-plant combustion and other industrial sources that would otherwise be released into the atmosphere is captured, compressed and injected into underground geologic formations for safe, secure and permanent storage.[41]	CCS has the potential to reduce up to 45% of California's emissions.[42] In 2019, 26 USC Section 45Q provided tax credits worth $31/Metric Ton of CO_2 for CCS projects that inject CO_2 into dedicated geological storage and $19/ Metric ton of CO_2 for CO_2 utilization and direct air capture projects. The value of credits rises linearly to $50/Metric Ton of CO_2 and $35/Metric Ton CO_2 respectively by 2026 and with inflation thereafter.[43,44] The stored carbon may be used as fuel for industrial processes, such as development of synthetic gas.[45]	High capital costs of fuel processing and CCS, and the absence of robust economic incentives to support CCS construction are barriers to implementation.[46] Stored captured carbon has the potential to leak.[47]	Limited data are available on commodity costs since no fossil gas-fired plants in the US currently have CCS on-site. Capital costs for the Petra Nova CCS plant, a coal-fired facility, were approximately $1 billion.[48]
Conventional fossil gas without CCS	Conventional fossil gas is the incumbent fuel in the gas delivery system.	No further technological development is necessary. The gas infrastructure system is extensively built out and widely accessible. Nearly 90% of California homes are already connected to the gas delivery system.	Concerns over emissions from combustion, indoor and outdoor air quality, and the prospect of methane leakage.[49,50] If fossil gas continues to be used, California will need to reduce emissions from other sources within the energy sector.	2050 Forecast: commodity cost $0.59/therm[51]

41 Townsend, A., & Havercroft, I. (2019). The LCFS and CCS protocol: An overview for policymakers and project developers. Retrieved October 10, 2020, from https://www.globalccsinstitute.com/wp-content/uploads/2019/05/LCFS-and-CCS-Protocol_digital_version.pdf

42 Burton, E. (2010). WESTCARB Regional Sequestration Partnership, Carbon Capture & Sequestration in the California Context, Accessed on October 6 from https://www.nrdc.org/sites/default/files/glo_10062101c.pdf

43 2019. (n.d.). Innovating energy solutions. Retrieved October 10, 2020, from https://corporate.exxonmobil.com/Research-and-innovation/Research-and-development-highlights

44 Jones, A., & Sherlock, A. (2020). The Tax Credit for Carbon Sequestration (Section 45Q). Retrieved October 12, 2020, from https://fas.org/sgp/crs/misc/IF11455.pdf

45 Salvi, Dr. B.L. & Jindal, Sudhakar. (2019). Recent developments and challenges ahead in carbon capture and sequestration technologies.

46 Leung, D. Y., Caramanna, G., & Maroto-Valer, M. M. (2014). An overview of current status of carbon dioxide capture and storage technologies. *Renewable and Sustainable Energy Reviews*, 39, 426-443.

47 Salvi, Dr. B.L. & Jindal, Sudhakar. (2019). Recent developments and challenges ahead in carbon capture and sequestration technologies, Table 5- Comparison of CCS with other clean technologies for energy generation

48 Dubin, K. (2017). EIA report on Petra Nova is one of two carbon capture and sequestration power plants in the world. Retrieved October 12, 2020 from https://www.eia.gov/todayinenergy/detail.php?id=33552

49 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 37.

50 Greene, S. & Prescott, L. (2020). California Should Go All-Electric in New Construction—State's Largest Utility Agrees -Rocky Mountain Institute Retrieved on October 10,2020 from https://rmi.org/california-should-go-all-electric-in-new-construction-states-largest-utility-agrees

51 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 37.

FUEL OPTION	DEFINITION	OPPORTUNITIES	CHALLENGES	COMMODITY COST
Decarbonized Electricity	Electricity generated with renewable resources.	Relatively low cost pathway to economy-wide decarbonization.[52] Electric infrastructure is broadly built out and accessible. Electric appliances for space and water heating, clothes drying, and cooking are widely available to replace fossil gas counterparts. Compared to fossil gas, the use of decarbonized electricity improves outdoor air quality and public health outcomes.[53]	Requires changes to both new construction practices as well as retrofits of the existing building stock.[54] In cold climates, electric resistance heating lead to substantial new electric-peak demands and the needs for new electric infrastructure[55]	2020 Forecast: 18.1 cents/ kWh electricity, $1.6/ therm gas. 2050 Forecast: 26.3 cents/ kWh electricity, $5.5 - $9/therm gas[56]
Biomethane or Renewable Natural Gas (RNG)	Pipeline quality biogas is referred to as biomethane or renewable natural gas. Biomethane is derived from waste biogas resources via anaerobic digestion, and from waste or residues via gasification of biomass (a biofuel production process). Fuel sources include municipal waste, manure, agriculture and forest residues.[57]	Biomethane is the most commercialized and lowest cost gaseous alternative.[58] The 2050 total potential for California is estimated at 6.35 billion therms.[59] In-state only (assuming all feedstocks go to RNG) = 387.4 BCF/year, 613 BCF per year including imports, while US total is estimated at 4785 BCF/year.[60]	Competing uses for biomethane, such as for transportation, limit availability and access for the energy sector. Demand is expected to be about 1.3 quadrillion Btu by 2050, but biomethane provides a maximum of 0.6 quads in the absence of any competing demands for this resource.[61]	Range of $0.7 to $2.0/therm[62,63,64]

52 Greene, S. & Prescott, L. (2020). California Should Go All-Electric in New Construction—State's Largest Utility Agrees -Rocky Mountain Institute Retrieved on October 10,2020 from https://rmi.org/california-should-go-all-electric-in-new-construction-states-largest-utility-agrees
53 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 5.
54 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 2.
55 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 15.
56 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 39.
57 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 17.
58 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 4.
59 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 19.
60 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page -D-23.
61 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 25.
62 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020).
63 ICF (2019), Renewable Source of Natural Gas, https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/.
64 IEA (2020) Outlook for biogas and biomethane: Prospects for Organic Growth, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth.

FUEL OPTION	DEFINITION	OPPORTUNITIES	CHALLENGES	COMMODITY COST
Green Hydrogen	Hydrogen derived efficiently from zero-carbon electricity electrolysis[18]	Green hydrogen may be produced with curtailed renewable energy and stored seasonally.[65] Hydrogen can be used in other sectors, such as transportation and agriculture, which could provide additional revenue streams.[66]	Limited pipeline blends (up to 7% by energy & 20% by volume) are possible without costly infrastructure upgrade.[67]	$2.0/Therm in 2050[68]
Synthetic Gas	Methane produced synthetically from hydrogen and a renewable CO_2 source.	The efficiency reaches 56 percent with bio-CO_2 and 45 percent with direct air capture in 2050.[69]	Low-cost sources of climate-neutral CO_2 (waste bio-CO_2) are relatively limited. Direct Air Capture has limited commercialization, expensive and is highly energy-intensive (150 to 470 KWh electricity input and 3.2 to 10.1 MMBtu of heat input per tonne of CO_2 captured.	$3.0 - 8.6/therm in 2050[70]
District Heating/ Combined heating and cooling	A heat recovery-based heating and cooling system that could be powered by renewable electricity instead of fossil gas.[71]	The thermal overlap and corresponding opportunity for heat recovery totals 75 percent, with 93 percent of campus heating and hot water needs able to be met by recovering 57 percent of the waste heat from the chilled-water system. Colder regions can utilize the same heat recovery equipment for large scale ground source heat exchange. Ground source heat exchange can boost annual sustainable heat supply from 50 percent up to almost 100 percent via building heat recovery alone.[72]	The economics and sustainability must be analyzed over the long term	

65 Driscoll, W. (2020), Hydrogen is the first viable option for seasonal storage-PV Magazine. Accessed on October 10, 2020 from https://www.pv-magazine.com/2020/03/16/hydrogen-is-the-first-viable-option-for-seasonal-storage
66 NREL, (2020). Answer to Energy Storage Problem Could Be Hydrogen (2020), Accessed on October 10, 2020 from https://www.nrel.gov/news/program/2020/answer-to-energy-storage-problem-could-be-hydrogen.html
67 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 4
68 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 24.
69 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 38
70 E3, The Challenge of Retail Gas in California's Low Carbon Future, (2020), Page 24
71 Stanford University's "fourth generation" District energy system Combined heat and cooling provides a path to sustainability (2016), accessed on October 10, 2020 from https://sustainable.stanford.edu/sites/default/files/IDEA_Stagner_Stanford_fourth_Gen_DistrictEnergy.pdf
72 Stanford University's "fourth generation" district energy system Combined heat and cooling provides a path to sustainability (2016), accessed on October 10, 2020 from https://sustainable.stanford.edu/sites/default/files/IDEA_Stagner_Stanford_fourth_Gen_DistrictEnergy.pdf