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SoCalGas Comments on the Proposed Changes to the 2022 Energy Code Update Rulemaking

Additional submitted attachment is included below.

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June 21, 2021

The Honorable J. Andrew McAllister
California Energy Commission
Docket Unit, MS-4
Docket No. 21-BTSD-01
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: Comments on the Proposed Changes to the 2022 Energy Code Update Rulemaking

Dear Commissioner McAllister:

Southern California Gas Company (SoCalGas) appreciates the opportunity to provide public comments on the California Energy Commission's (CEC's) Proposed Changes to the California Code of Regulations, Title 24, Parts 1 and 6 (Proposed 2022 California Energy Code). We recognize the breadth of the challenge being undertaken by the CEC, particularly to project and assess future costs and benefits, considering the magnitude of energy transition unknowns, to ensure that California's new building stock is created as energy efficiently and cost effectively as reasonably possible. While mindful of the challenge to project into the future, there is no uncertainty regarding the imperative to substantially reduce greenhouse gas emissions from the built environment. SoCalGas acknowledges the requisite level of effort, including that which the CEC is undertaking to update the foundational building code grounded in energy efficiency. With that in mind, we offer several observations and suggestions for consideration.

As expressed by the Time Dependent Valuation (TDV) analyses, the intended benefits of the proposed code changes are highly sensitive to variables relating to the future customer cost for the electric supply and delivery infrastructure compared to the future cost for gas supply and delivery infrastructure. To the extent that the CEC's projections do not accurately reflect future energy system costs, the assumed benefits may not materialize and could adversely impact public welfare, especially relating to housing affordability (and lack thereof). As discussed in greater detail below, numerous data points, facts and sensitivity analyses suggest that certain assumptions embedded in the Proposed 2022 California Energy Code are either overly optimistic and/or do not reflect the most current data sets - suggesting that cost-effectiveness projections for the cost of electric and gas supply and delivery infrastructure do not reasonably reflect likely outcomes.

As one example, SoCalGas respectfully submits that an overly pessimistic forecast of the Retail Gas Prices used to calculate the TDV is, in and of itself, sufficient to infirm much of the economic analysis that the proposed updated building code relies upon. Conversely, overly optimistic assumptions on maintenance costs for heat pump water heaters (HPWHs) have a similar impact.

While we recognize the limitations inherent in forecasting energy costs into the future, our comments are intended to help clarify prospective risks and benefits. Specifically, our comments focus on the following: **(1)** Additional details are needed to fully understand cost-effectiveness tradeoffs resulting from the proposed code changes to the Proposed 2022 California Energy Code; **(2)** The need for sensitivity analyses of operation and maintenance cost assumptions and gas prices; **(3)** Further analysis of the interactive effects of heat pump water heaters with heating, ventilation, and air conditioning systems; **(4)** Additional considerations for proposed requirements for kitchen exhaust systems and range hood ventilation; and **(5)** Risks associated with battery storage assumptions.

1. Additional Details are Needed to Fully Understand and Assess Cost-Effectiveness Tradeoffs within the Proposed Code Changes to the Proposed 2022 California Energy Code

The California Health and Safety Code establishes nine criteria for the CEC's assessment of prospective updates to the Proposed 2022 California Energy Code, including a required finding that "the cost to the public is reasonable, based on overall benefit to be derived from the building standards."[1] Further, the Warren-Alquist Act specifically directs the CEC to reduce the inefficient consumption of energy by prescribing new energy design standards for new residential and nonresidential buildings.[2] In doing so, the CEC is required to demonstrate that the standards adopted or revised be cost-effective and consider relevant factors "including, but not limited to, the impact on housing costs, the total statewide costs and benefits of the standard over its lifetime, economic impact on California businesses, and alternative approaches and their associated costs."[3] While other factors *may* be considered, the State Legislature specifically *directed* the CEC to assess the impact of energy code amendments on residential housing costs.

The CEC estimates a benefit-to-cost ratio for the Proposed 2022 California Energy Code to be 3.5 to 1 ($8.7 billion in lifetime benefits and $2.5 billion in lifetime costs). Many of the cost and benefit assumptions, however, are neither clear nor delineated by building sector. The CEC's cost-benefit analyses should include additional detail to accurately and transparently discern which measures are most cost-effective, and reasonable for California residents and businesses. For example, the document titled "Form 399 Narrative Memorandum" mentions one measure for the non-residential sector that may result

[1] Cal. Health & Safety Code Section 18930(a).
[2] Cal. Public Res. Code Section 25402(b).
[3] Cal. Public Res. Code Section 25402(b)(3).

in overall newly constructed building cost reductions (savings) estimated at $290 million.[4] However, the memorandum does not identify the measure or specify the cost of the measure. Similarly, the memorandum mentioned seven other measures that may result in aggregate added costs of $42.9 million for newly constructed buildings but does not clearly identify the benefits these measures would generate.[5] Additionally, in the Economic Impact Statement,[6] the CEC expresses that 88 percent of the costs are incurred in the residential sector and 12 percent of the costs are incurred in the non-residential sector but does not indicate which measures generate the respective cost impacts. It is thus unclear and should be ascertainable whether: *the benefits also follow this ratio with 88 percent of the benefits attributed to the residential sector which is incurring 88 percent of the costs?*

Unbundling the CEC's cost and benefit assumptions is critical to understanding the impact of the proposed code changes and assessing specific impacts on housing costs, as required by State Law. If the overwhelming percentage of increased costs are being borne by the residential sector, but the overall benefits are attributable to the non-residential sector, the relative cost-effectiveness will be obscured and questionable. It is in the public interest for the proposal to express, in detail, the granular costs and benefits attributable to each potential measure and how they will affect the cost-effectiveness for both the residential and non-residential sectors distinctly. We respectfully request that the CEC provide a breakdown of total costs and benefits from the Proposed 2022 California Energy Code for each potential measure, delineated by non-residential and residential sectors. Doing so will allow individuals and businesses to better understand the important tradeoffs between different compliance options.

2. Sensitivity Analyses Are Needed for Operation and Maintenance Cost Assumptions and Gas Prices

Sensitivity analyses provide a way to manage the uncertainty inherent in data analysis. In a 2017 report assessing how regulatory agencies can improve their analyses, the California Legislative Analyst Office (LAO) found that most state agencies do not adequately assess uncertainty and that sensitivity analyses "provides the agency and the public with a better understanding of the risks—both positive and negative—of a particular approach."[7] To this end, SoCalGas performed a fairly straightforward assessment on the operation and maintenance (O&M) costs for HPWHs to determine the sensitivity of the economic analysis used by the CEC to validate the Proposed 2022 California Energy Code changes, based on the economic comparison between the gas and electric technology options. Our analysis shows a thin cost-effectiveness margin between electric and gas appliances that is sensitive to small deviations from retail electricity or gas prices. Accordingly, it appears very likely that the proposed code changes may not achieve the expected greenhouse gas (GHG) reductions per dollar spent, and consequently may not be the most cost-effective approach. For the detailed sensitivity analysis, please see Appendix A.

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[4] *See* California Energy Commission, *TN 237721: Form 399 Narrative Memorandum*, Docket: 21-BSTD-01, 6 May 2021, at 5. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=237721&DocumentContentId=70944.
[5] Ibid.
[6] *See* California Energy Commission, *TN 237722: Form 399 for the Proposed 2022 Energy Code,* Docket: 21-BSTD-01, 6 May 2021, at 2. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=237722&DocumentContentId=70943.
[7] Mac Taylor, *Improving California's Regulatory Analysis*, California Legislative Analyst Office, February 2017, at 14. Available at https://lao.ca.gov/reports/2017/3542/Improving-CA-Regulatory-Analysis-020317.pdf.

Admittedly SoCalGas does not have access to the full range of modeling tools used by the CEC so as to fully replicate the CEC analysis. Hence different elements of the forecast are expected to change in ways not captured in this simple sensitivity analysis. However, the fact that simple and straightforward revisions to a very limited set of the assumptions used in the modeling leads to a very different set of results suggests that significantly more review of these assumptions is necessary and appropriate before finalizing the Proposed 2022 California Energy Code.

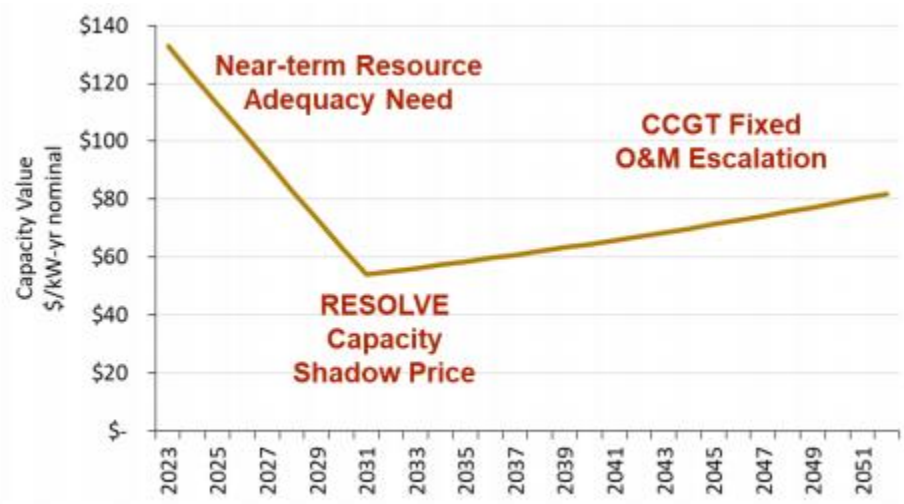
We further note that a more recent and accurate forecast of natural gas costs is available and strongly recommend that the CEC undertake sensitivity analysis to examine the results of the Proposed 2022 California Energy Code cost-effectiveness analysis using a more reasonable gas price forecast. As presented in Appendix B to these comments, the natural gas costs used in the Proposed 2022 California Energy Code analysis are based on an outdated forecast that overstates current market expectations regarding future natural gas costs. Specifically, the Retail Rate Adjustment is based on an inaccurate and simplistic assumption for natural gas system costs that significantly overstates expected retail natural gas prices. Moreover, we provide in Appendix B data suggesting that the Proposed 2022 California Energy Code analysis dramatically overstates low carbon gas supply costs, particularly for hydrogen, relative to current industry expectations and only includes conservative estimates of biogas potential.

A more realistic assessment of future retail natural gas prices would result in lower prices and lower customer attrition. Similarly, a more realistic assessment of low carbon gas supply costs would lead to additional low carbon gas supplies and similar GHG emissions reductions. Lastly, a lower retail natural gas price could change the cost relationship between natural gas and electricity in many of the new building applications assessed in the Proposed 2022 California Energy Code analysis leading to different recommendations based on the economic comparison of natural gas and electric end-use options. If the sensitivity case results in significant changes to the results of the Proposed 2022 California Energy Code analysis, we respectfully request that the CEC conduct a more rigorous analysis of the gas price forecast before finalizing the proposed code changes to the Proposed 2022 California Energy Code. Details addressing the forgoing considerations for the CEC forecast, no/low carbon gas supply costs, and biogas potential can be found in Appendix B.

Likewise, we note that the gas supply costs associated with the operation of the combined cycle gas turbine (CCGT) resources are likely understated. According to the CEC analysis, the cost of the CCGT assets is constant in real terms after 2031 as indicated in Figure 1.[8]

[8] From Final 2022 Time Dependent Valuation and Source Energy Metric Data Sources and Inputs, May 2020, Docket Number: 19-BSTD-03, TN# 233345.

Figure 1: Capacity Value Forecast



However, this assumption is at odds with the need to maintain the means by which CCGTs obtain fuel (the gas transportation and distribution networks) over the same period during which throughput and distribution customer count are projected to decrease. In practical effect, CCGTs will be bearing more of the gas system costs (including for firm transportation service) with fewer units of electricity production, which will result in a corresponding increase in the costs for electricity and output. Because gas throughput will decline and infrastructure costs will not decline commensurately, the electricity prices from CCGT will not remain constant after 2031 but will likely increase. Please see Appendix C for additional detail.

3. Further Analysis of the Interactive Effects of Heat Pump Water Heaters with Heating, Ventilation and Air Conditioning System.

Heat Pumps are a proven technology, reducing energy consumption and carbon emissions across all building types, as validated by the CEC's in-depth analysis of the performance and overall cost-effectiveness of heat pumps compared to other alternatives. We note, however, some areas where the CEC analysis overlooks, variability in the costs of installing and operating a heat pump for water or space heating. The Proposed 2022 California Energy Code requires the storage tank of HPWHs to be in the garage or in a conditioned space. A HPWH, when installed in a conditioned space, interacts with the heating, ventilation, and air conditioning (HVAC) system by extracting heat from the space in which it is located. This includes a cooling bonus in the summer and a heating penalty in the winter. In the "Single Family Heat Pump Documentation,"[9] these interactive effects are accurately captured since both heat pump space heaters (HPSHs) and HPWHs are modeled together. Their cost-effectiveness is analyzed against gas furnaces and gas instantaneous water heaters, respectively. However, for mixed fuel homes where a HPWH is installed and a gas furnace is used for space heating, the heating penalty induced by the HPWH on the gas consumption could be significant. We are unaware of any assessment, that analyzes the

[9] Residential HVAC and Residential Water Heating, Prepared by CEC, May 2021, Docket Number 21-BSTD-02, TN# 237850

interactive effects between HPWHs and gas-based space heating on the cost-effectiveness of mixed fuel homes, especially in climate zones with substantial heating load. If such analysis was not performed, we respectfully request that the CEC include it in the cost-effectiveness analysis for mixed fuel homes assessing /comparing to the scenario with gas-based space and water heating.

4. Proposed Requirements for Kitchen Exhaust Systems and Range Hood Ventilation

Cooking is a well-recognized source of particulate matter (PM) in homes. PM is primarily emitted from the cooking process (*i.e.*, frying, sautéing, toasting, etc.) and the emissions are similar whether the energy source of the stove is gas or electric. We recommend using a single capture efficiency standard for each dwelling unit size regardless of fuel source. We believe that this will be more health-protective and will decrease all indoor pollutants to a greater extent. Despite the public health benefits ventilation offers, a survey conducted by Lawrence Berkeley National Laboratory (LBNL)[10] shows that many people do not use their range hoods because they think the hood is not needed, simply forget it is there, or find it is too noisy. We suggest the CEC consider range hoods that turn on automatically when the stove is in use. This strategy has been used in Japan and has been found to be effective.[11] We also recommend that more engineering work be performed to develop quieter hoods so that people are more likely to use them. Please see Appendix D for additional details.

5. Risks Associated with Battery Storage Assumptions

The data sources used by the CEC for estimating the costs of residential energy storage are reputable and appear reasonable. However, residential energy storage lacks manufacturers and historical data to estimate costs as accurately as utility storage. Therefore, the risks associated with availability, reliability, and operations and maintenance should be considered in addition to energy storage costs. Please see Appendix E for more details.

In closing, we appreciate the opportunity to provide public comments on this matter of critical importance to the residents of California.

Respectfully,

/s/ Kevin Barker

Kevin Barker
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[10] Yang Kim, Brennen Less, Brett Singer, Wanyu R. Chan, and Iain Walker, *Ventilation and Indoor Air Quality in New California Homes with Gas Appliances and Mechanical Ventilation*, Lawrence Berkeley National Laboratory, April 2020. Available at https://escholarship.org/uc/item/44g399sb.

[11] *See* Presentation by Kazukiyo Kumagai of the California Department of Public Health at the CEC Workshop on September 30, 2020, Docket: 21-BSTD-03. Available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-BSTD-03.

Appendix A: Sensitivity Analysis of the Gas Prices and the Heat Pump Water Heater Operations and Maintenance Assumptions

SoCalGas performed a relatively simple assessment of the impact of the issues discussed in the body of our comments on the levelized value of gas savings used in the TDV analysis to determine the sensitivity of the economic analysis used to support justify the Proposed California 2022 Energy Code changes. The focus of this assessment is on the results of the economic comparison between gas and electric technology options.

The first change we made was to the TDV retail rate adjustment. The Policy Compliant – Res and Non-Res 2050 values for Natural Gas Retail Rate Adjustment - CA Avg. ($/MMBtu) started from a 2023 value of $17.08/MMBtu, with the future rate of growth cut in half relative to the original TDV model, reflecting a more realistic assessment of the decline in system costs that would result from a decline in customers and throughput. The adjustment in the Retail Rate resulted in a decline in the levelized value of gas savings of about $6.90/MMBtu, leading to a reduction in the natural gas TDV of about 21 percent. The second adjustment applied to the TDV model to reduce gas commodity prices. SoCalGas believes that these prices were overstated due to the use of a less than up-to-date gas price forecast. To estimate the impact, we reduced the gas price forecast used in the TDV model by 14 percent. This value then fed into the overall natural gas commodity costs. The adjustment in conventional gas commodity prices resulted in a decline in the levelized value of gas savings of about $0.50/MMBtu.

We also modified the gas prices used in the TDV analysis to reflect a more realistic assessment of future delivered hydrogen costs. The hydrogen pricing adjustment envisioned a future where the DOE Hydrogen Energy Earthshot target of $1/kg for green hydrogen ($7.44/MMBtu) by 2030 was achieved. This TDV sensitivity scenario simplified modeling by assuming a constant $7.44/MMBtu after 2030, reflecting modest reductions in real costs after achieving the 2030 goal. Consequently, SoCalGas also modeled a greater decrease in natural gas contributions to the Policy Compliant Natural Gas Fuel Blend over time than the original TDV model presumed, due to increased competitiveness of hydrogen under these adjusted price scenarios. It was assumed that conventional natural gas would drop to 50 percent of the blend by 2050 with biogas, synthetic natural gas (SNG), and hydrogen making up the remainder. For SNG, we assumed an incremental adder to the hydrogen cost based on an average of the CEC estimated incremental cost for SNG from bio-CO_2 and direct air capture ($15/MMBtu). Thus, SNG is projected to cost $22.44/MMBtu. The increase in commodity costs were largely offset by reductions in the cap-and-trade emissions payments, emissions abatement costs, and methane leakage values. The increase in SNG would also have the impact of reducing the price of the cap-and-trade emissions and emissions abatement. However, we were unable to estimate the impact of the increase in low carbon fuels on the prices for these variables.

Additionally, in the "Single Family Heat Pump" Report,[12] a detailed cost-effectiveness analysis of heat pump water heaters (HPWHs) compares gas furnace/air conditioner combinations for space heating and

[12] Residential HVAC and Residential Water Heating, Prepared by CEC, May 2021, Docket Number 21-BSTD-02, TN# 237850.

instantaneous gas water heater for water heating. For water heating end-uses, the CEC used cost data from the "City of Palo Alto 2019 Title 24 Energy Reach Code Cost Effectiveness Analysis." This analysis estimated maintenance costs for HPWHs to be zero, because HPWHs do not require a service professional for additional maintenance whereas gas instantaneous water heaters require flushing every five years by a service professional. This results in a lifetime benefit of $2,000 for a HPWH relative to a gas instantaneous water heater.

However, there are varying perspectives regarding the comparative maintenance costs of HPWHs and gas-based water heaters. It seems unlikely that most HPWH owners will realize the savings in maintenance assumed in this analysis. A study published by the National Renewable Energy Laboratory (NREL) in 2013 estimated HPWHs to have a maintenance cost of $100 every 5 years, whereas typical gas-based water heaters were assumed to have no maintenance costs.[13] Another NREL study compared the maintenance cost of different water heater technologies and estimated the likelihood that the maintenance activities would be performed. The study estimated the optimal maintenance cost for a HPWH to be $217.55 annually compared to $71.71 per year for a gas tankless water heater.[14] The study also showed the likelihood of people realistically maintaining their water heaters, which is much lower for HPWHs compared to gas tankless water heaters. This would bring down the actual annual maintenance cost for HPWHs to $17.41 per year and for gas tankless water heaters to $40.16 per year. Even with the lower likelihood that customers will get their water heater maintained, HPWHs do not come without maintenance costs.

Furthermore, according to a 2010 Lawrence Berkeley National Laboratory (LBNL) report published by the American Council for an Energy Efficient Economy (ACEEE), manufacturers recommend electric storage water heaters be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life.[15] The NREL study[16] also highlighted the importance of considering maintenance costs for all water heater technologies that it analyzed since no annual performance degradation was considered. This implies that the maintenance was assumed to keep the equipment operating like new throughout its lifetime. We would like to emphasize that if HPWHs are not expected to have any maintenance costs, they are likely to experience performance degradation over their lifetime and not generate the same amount of energy savings as currently estimated.

In the "Single Family Heat Pump Documentation," a HPWH is $1,178 less expensive than gas instantaneous water heaters. The $1,979 maintenance cost for instantaneous gas water heaters seems to be the key component that makes HPWHs more cost-effective than the gas tankless water heaters. Table 1

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[13] Jeff Maguire, Jay Burch, Tim Merrigan, and Sean Ong, *Energy Savings and Breakeven Cost for Residential Heat Pump Water Heaters in the United States*, National Renewable Energy Laboratory, July 2013, at 31. Available at https://www.nrel.gov/docs/fy13osti/58594.pdf.

[14] Jeff Maguire, Xia Fang, and Eric Wilson, *Comparison of Advanced Residential Water Heating Technologies in the United States*, National Renewable Energy Laboratory, May 2013, at 58. Available at https://www.nrel.gov/docs/fy13osti/55475.pdf.

[15] Victor Franco, Alex Lekov, Steve Meyers, and Virginia Letschert, *Heat Pump Water Heaters and American Homes: A Good Fit?*, Presented at the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, August 2010, at 9. Available at https://www.osti.gov/biblio/1016712.

[16] Jeff Maguire, Xia Fang, and Eric Wilson, *Comparison of Advanced Residential Water Heating Technologies in the United States.*

provides the lifecycle cost-effectiveness for a 2,100 ft^2 single family home as analyzed by the CEC for each climate zone as well as a different scenario. Following the format of the analysis done in the "Single Family Heat Pump Documentation" report, we repeated the analysis with a slight variation in the maintenance cost assumptions. We assumed that the maintenance cost of HPWHs is the same as gas instantaneous water heaters and the incremental cost under "*Higher HPWH Incremental Cost Scenario"* in Table 1 reflects that assumption. As can be seen, HPWHs are not cost-effective in Climate Zones 1 and 16.

Table 1. Equal Maintenance Costs for Gas Instantaneous and HPWH

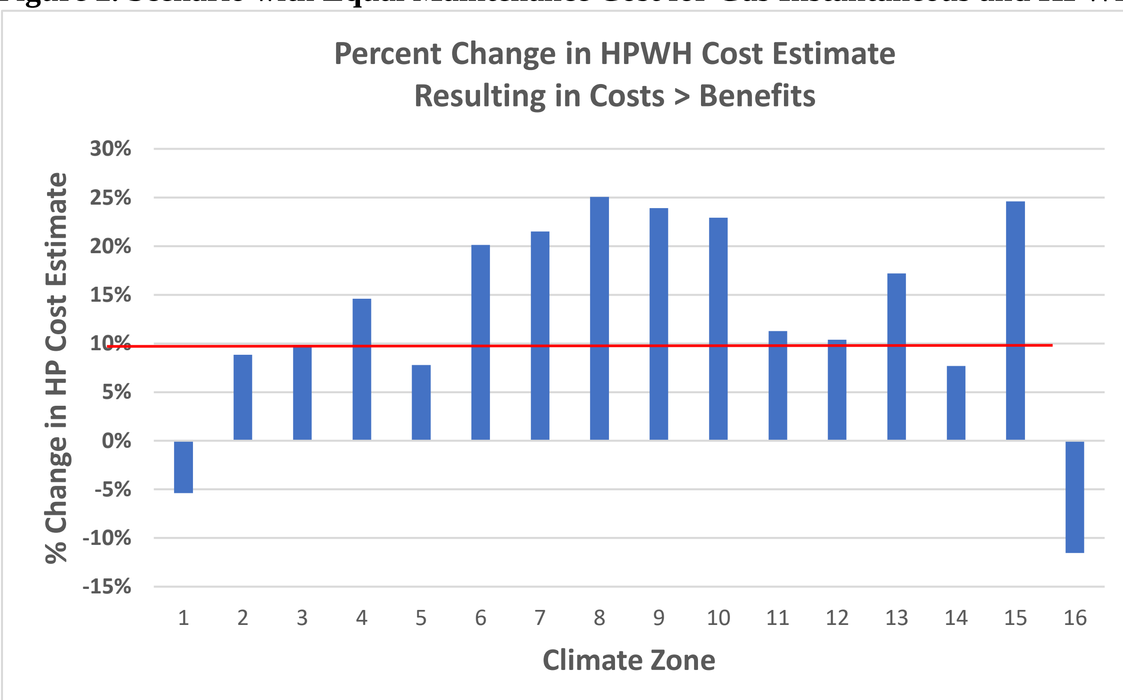
Climate Zone	Benefits TDV Energy Cost Savings + Other Present Value (PV) Savings (2023 PV $)	Data from CEC Report – SF Heat Pump Documentation		Higher HPWH Incremental Cost Scenario	
		Costs Total Incremental PV Costs (2023 PV $)	Benefit-to-Cost Ratio	Costs Total Incremental PV Costs (2023 PV $)	Benefit-to-Cost Ratio
1	$ 418.00	$ (1,178.00)	Undefined[17]	$ 801.00	0.52
2	$ 1,428.00	$ (1,178.00)	Undefined	$ 801.00	1.78
3	$ 1,500.00	$ (1,178.00)	Undefined	$ 801.00	1.87
4	$ 1,838.00	$ (1,178.00)	Undefined	$ 801.00	2.29
5	$ 1,355.00	$ (1,178.00)	Undefined	$ 801.00	1.69
6	$ 2,231.00	$ (1,178.00)	Undefined	$ 801.00	2.79
7	$ 2,329.00	$ (1,178.00)	Undefined	$ 801.00	2.91
8	$ 2,583.00	$ (1,178.00)	Undefined	$ 801.00	3.22
9	$ 2,500.00	$ (1,178.00)	Undefined	$ 801.00	3.12
10	$ 2,430.00	$ (1,178.00)	Undefined	$ 801.00	3.03
11	$ 1,602.00	$ (1,178.00)	Undefined	$ 801.00	2.00
12	$ 1,540.00	$ (1,178.00)	Undefined	$ 801.00	1.92
13	$ 2,024.00	$ (1,178.00)	Undefined	$ 801.00	2.53
14	$ 1,348.00	$ (1,178.00)	Undefined	$ 801.00	1.68
15	$ 2,550.00	$ (1,178.00)	Undefined	$ 801.00	3.18
16	$ 752.00	$ (461.00)	Undefined	$ 1,518.00	0.50

Considering other studies that show a variety of perspectives on maintenance cost of HPWHs, we suggest that it is informative to assess how these perspectives could impact cost-effectiveness. The objective of presenting this data is to show that there is substantial uncertainty in the cost-effectiveness of these technologies based on the variability in maintenance cost, and a slight variability in assumptions could cause the overall investment to not generate the projected payback.

[17] Undefined means no costs associated with this measure.

Additionally, SoCalGas ran some sensitivity analysis to check the variations in incremental cost (on top of the maintenance cost addition) that would impact the cost-effectiveness of these technologies. The results are shown in 2, which shows the percent change in HPWH cost that would result in the total cost exceeding the total long-term benefits offered by this technology, in each climate zone. As is clear from the Figure 2, a 10 percent increase (indicated by a red horizontal line) in the cost of a HPWH could potentially result in overall higher costs than benefits in several of the climate zones. Climate zones 1 and 16 show they are already not cost effective using the same maintenance costs, but with an increase of 10 percent maintenance costs climate zones 2, 3, 5, and 14 are also no longer cost-effective. Uncertainty in other variables, including the TDV values for natural gas and electricity could result in changes in the economic balance in additional climate zones. We also want to point out that incremental costs can vary widely based on factors such as location, contractor, installation scenario as well as customer behavior, which has a significant impact on the actual incurred maintenance cost and can vary from customer to customer.

Figure 2. Scenario with Equal Maintenance Cost for Gas Instantaneous and HPWH



In the "Single Family Heat Pump" Report, it is identified that the authors used cost data from the "City of Palo Alto 2019 Title 24 Energy Reach Code Cost Effectiveness Analysis," which was further updated using data from Home Depot and supplyhouse.com. While these sources provide a reasonable estimate of the equipment and installation costs of a drain hot water (DHW) system, we suggest that rather than a single data point, a range of values would more accurately capture the costs of installing and maintaining these technologies to customers or builders throughout the State. Similarly, the "All-Electric Multifamily CASE Report"[18] states that the HVAC and DHW system incremental first cost estimates were obtained

[18] All-Electric Multifamily Compliance Pathway, Prepared by TRC, April 2021, Docket Number 21-BSTD-01, TN# 237692

from a single mechanical contractor. The CASE Report also discusses the availability of cost data from actual projects through consultants and installers, which according to the authors, was not used because of unstated inconsistencies in the data and the fact that building specific costs could not be separated from the total costs, thus making it difficult to compare across scenarios. We would like to emphasize that without considering actual projects costs from multiple locations or contractors across the state, the analysis misses several possible construction and installation considerations that could be unavoidable in real life and could substantially impact the cost-effectiveness of such investments for the customer.

Natural Gas TDV Sensitivity Analysis and the Impacts on the 2022 Proposed California Energy Code

The TDV formulation plays a key role in development of 2022 Proposed California Energy Code and it is crucial that it accurately captures, to the extent possible, the most recent data sources available. Thus, we looked at the inputs to the natural gas TDV calculations that could be reevaluated to consider the sensitivity of the overall TDV. Multiple scenarios were modeled and the impact on space heating and water heating were evaluated for single family buildings. CBECC-Res 2022[19] was used to run simulations and obtain 8760 consumption load shapes for natural gas and electricity.

Modeling Assumptions: We used the 2,100 ft^2 single family building prototypes provided as part of CBECC-Res 2022 software and made changes to generate our baseline and proposed scenarios like the ones used for “Single Family Heat Pump” Report[20] in which the cost-effectiveness of heat pumps was calculated for space heating and water heating end-uses. The baseline scenario employed a gas furnace for space heating and gas instantaneous water heater for water heating, whereas the proposed scenario used HPWHs for both end-uses. No changes were made to the prototypes except for switching between gas based and electric based HVAC and DHW systems for baseline and proposed scenarios, respectively. Default efficiencies already present in the tool were used for modeling. To our surprise, the annual electricity and natural gas consumption for water heating and space heating end-uses as generated by the latest version of CBECC-Res 2022 differed from the values in the “Single Family Heat Pump” Report.[21] The annual TDV energy cost based on the 2022 TDV values for both electricity and gas are provided in Table 2.

Default Scenario: This is the baseline case without any change in the TDV values, consistent with the CEC analysis. Since the annual electricity and natural gas consumption generated by CBECC-Res 2022 outputs differed from the values in the “Single Family Heat Pump” Report, we wanted to present the default scenario before presenting the results for variabilities in the natural gas TDV. This allows us to accurately analyze the relative impact on the cost-effectiveness of heat pump technologies. Table 2 below

[19] CBECC-RES Compliance Software Project: CBECC-RES 2022. Available at http://www.bwilcox.com/BEES/cbecc2022.html.
[20] Residential HVAC and Residential Water Heating, Prepared by CEC, May 2021, Docket Number 21-BSTD-02, TN# 237850
[21] Residential HVAC and Residential Water Heating, Prepared by CEC, May 2021, Docket Number 21-BSTD-02, TN# 237850

provides the electricity and natural gas 30-year TDV cost savings (2023 Present Value) which are subtracted to get the 30-year TDV energy cost savings.

Table 2. Modelling Output: CBECC-Res 2022
Analysis of TDV Energy Cost Savings Over 30-Year Period of a
2,100 ft^2 Single Family Building Prototype: Heat Pump Water Heating

Climate Zone	30-Year TDV Electricity Cost Savings (2023 PV)	30-Year TDV Natural Gas Cost Savings (2023 PV)	30-Year TDV Energy Cost Savings (2023 PV)
1	$ (7,695.01)	$ 7,667.99	$ (27.03)[22]
2	$ (5,805.47)	$ 7,342.45	$ 1,536.98
3	$ (5,712.08)	$ 7,307.01	$ 1,594.93
4	$ (4,924.27)	$ 6,874.50	$ 1,950.24
5	$ (5,846.47)	$ 7,308.61	$ 1,462.14
6	$ (4,261.47)	$ 6,594.80	$ 2,333.33
7	$ (4,255.70)	$ 6,585.12	$ 2,329.42
8	$ (3,761.10)	$ 6,364.68	$ 2,603.58
9	$ (3,948.73)	$ 6,437.55	$ 2,488.82
10	$ (4,054.37)	$ 6,430.24	$ 2,375.88
11	$ (4,953.62)	$ 6,619.68	$ 1,666.06
12	$ (5,294.42)	$ 6,897.69	$ 1,603.27
13	$ (4,344.95)	$ 6,404.16	$ 2,059.21
14	$ (5,181.75)	$ 6,688.96	$ 1,507.21
15	$ (2,616.77)	$ 5,175.79	$ 2,559.03
16	$ (7,338.18)	$ 7,594.98	$ 256.80

For climate zone (CZ) 16, the single-family building prototype also included a drain water heat recovery (DWHR) system and so the cost of $771 as estimated by the CEC was also included in the incremental cost of the proposed scenario shown in Table 3 below. The TDV Energy Cost Savings from Table 2 and incremental costs of HPWHs are used to get the benefit-to-cost ratio provided in Table 3 below.

[22] The analysis in the "Single Family Heat Pump" Report by CEC shows a $400 TDV Energy Cost Savings in CZ1 for HPWHs compared to a $27 Energy Cost Increase as calculated based on the output from CBECC-Res 2022 and default TDV values provided in the "TDV_2022_Update_Model_ada" spreadsheet.

Table 3. Default Scenario
Lifecycle Cost-effectiveness of a 2,100 ft^2 Single Family Building Prototype:
Heat Pump Water Heating with No Maintenance Cost

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings (2023 PV)	Costs Total Incremental PV Costs (2023 PV)	Benefit-to-Cost Ratio
1	$ (27.03)	$ (1,178.00)	43.5
2	$ 1,536.98	$ (1,178.00)	Undefined
3	$ 1,594.93	$ (1,178.00)	Undefined
4	$ 1,950.24	$ (1,178.00)	Undefined
5	$ 1,462.14	$ (1,178.00)	Undefined
6	$ 2,333.33	$ (1,178.00)	Undefined
7	$ 2,329.42	$ (1,178.00)	Undefined
8	$ 2,603.58	$ (1,178.00)	Undefined
9	$ 2,488.82	$ (1,178.00)	Undefined
10	$ 2,375.88	$ (1,178.00)	Undefined
11	$ 1,666.06	$ (1,178.00)	Undefined
12	$ 1,603.27	$ (1,178.00)	Undefined
13	$ 2,059.21	$ (1,178.00)	Undefined
14	$ 1,507.21	$ (1,178.00)	Undefined
15	$ 2,559.03	$ (1,178.00)	Undefined
16	$ 256.80	$ (1,178.00)	Undefined

The analysis that follows considered sensitivity of two components: natural gas TDV and heat pump water heater maintenance costs. The impact of variability in each component, individually and combined, on the cost-effectiveness of heat pump technology was analyzed.

Table 4. Scenarios for Sensitivity Analysis

Scenario(s)	Description
Default Scenario	No changes in TDV values or incremental costs. Single Family 2,100 ft^2 simulated using latest CBECC-Res 2022.
Scenario 1: HPWH Cost Changes Only	No changes in TDV values but incremental HPWH O&M costs represent equal maintenance costs for gas and HPWHs.
Scenario 2: Retail Rate Adjustment Only	Reduced gas retail rate adjustment and no changes to the incremental HPWH O&M costs.
Scenario 3: Retail Rate & Gas Cost Only	Reduced Gas Retail Rate Adjustment, reduced gas commodity prices, reduced hydrogen and SNG prices, decreased conventional natural gas share in fuel blend, and no changes to the incremental HPWH O&M costs.
Scenario 4: Retail Rate & HPWH Cost Changes	Reduced gas retail rate adjustment. Incremental HPWH O&M costs represent equal maintenance costs for gas and HPWHs.
Scenario 5: Retail Rate, Gas Cost & HPWH Cost Changes	Reduced retail rate adjustment, reduced gas commodity prices, reduced hydrogen and SNG prices, decreased conventional natural gas share in fuel blend. Incremental HPWH O&M costs represent equal maintenance costs for gas and HPWHs.

Scenario 1: HPWH Cost Changes Only. In this case, there are no changes in TDV values, but the case does include incremental HPWH maintenance costs. Table 5 shows the cost-effectiveness of a HPWH when replacing gas instantaneous water heaters in a single-family building per each CZ assuming the maintenance cost of the HPWH is the same as the instantaneous gas water heater, increasing the incremental costs of a HPWH to $801.

The inclusion of more realistic maintenance costs for the HPWH significantly reduced the cost effectiveness of the HPWH relative to the instantaneous gas water heater in all climate zones and flipped the results of the analysis from electric to natural gas in CZs 1 and 16.

Table 5. Scenario 1: HPWH Cost Changes Only
Lifecycle Cost-effectiveness of a 2,100 ft^2 Single Family Building Prototype:
Heat Pump Water Heating with Maintenance Costs

Climate Zone	Benefits TDV Energy Cost Savings + Other PV Savings1 (2023 PV)	Costs Total Incremental Present Valued (PV) Costs2 (2023 PV)	Benefit-to-Cost Ratio
1	$ (27.03)	$ 801.00	0
2	$ 1,536.98	$ 801.00	1.92
3	$ 1,594.93	$ 801.00	1.99
4	$ 1,950.24	$ 801.00	2.43
5	$ 1,462.14	$ 801.00	1.83
6	$ 2,333.33	$ 801.00	2.91
7	$ 2,329.42	$ 801.00	2.90
8	$ 2,603.58	$ 801.00	3.25
9	$ 2,488.82	$ 801.00	3.10
10	$ 2,375.88	$ 801.00	2.96
11	$ 1,666.06	$ 801.00	2.07
12	$ 1,603.27	$ 801.00	2.00
13	$ 2,059.21	$ 801.00	2.57
14	$ 1,507.21	$ 801.00	1.88
15	$ 2,559.03	$ 801.00	3.19
16	$ 256.80	$ 1,518.00	0.17

Scenarios 2 & 4: Retail Rate Adjustments. SoCalGas believes that the retail rate adjustment used to project customer gas prices in the TDV analysis was likely overstated due to an incorrect assessment of the relationship between utility costs and throughput volumes and the number of customers. The Policy Compliant – Res and Non-Res 2050 growth rates for Natural Gas Retail Rates - CA Avg ($/MMBtu) were cut in half from the original TDV values as calculated using the TDV spreadsheet model. So, an adjusted linear trend from the model's original values for the rates in 2023 to new 2050 values was applied.

Scenarios 3 & 5: Retail Rate & Gas Cost Adjustments. The second adjustment applied to the TDV model was to reduce gas commodity prices. We believe that these were overstated because a more up-to-date gas price forecast was not utilized. CEC directed E3 to use the PLEXOS IEPR California EG Gas Price Forecast (Nominal $/MMBtu) for 2019 in the TDV analysis. Since we did not have access to the PLEXOS reports provided by the CEC to E3, we compared the values used in the TDV to the gas price forecasts from the EIA AEO for 2019, 2020 and 2021. We also compared the PLEXOS 2019 data from the TDV model to the AEO values. We found that the 2019 PLEXOS report overestimated natural gas spot price projections (in nominal dollars/MMBtu) at Henry Hub by 14 percent compared to the 2021 AEO. Thus, we utilized the *Adjustments* row in the Fuel Costs tab in the TDV spreadsheet model to reduce the 2019 PLEXOS-sourced EG Gas price Forecast by 14 percent. This value then fed into the overall natural gas commodity costs.

Lastly, we modified the hydrogen and SNG prices based on more recent forecasts of hydrogen energy prices. Building on the first two adjustments to natural gas TDV, we changed hydrogen price estimates to align with the DOE Hydrogen Energy Earthshot target of $1/kg for green hydrogen ($7.44/MMBtu, HHV basis) by 2030. This remains constant at $7.44/MMBtu after 2030. SNG costs were estimated at $15 above the cost of hydrogen, reflecting a 50/50 blend of bio-CO2 and CO2 from direct air conversion. With alternative fuels at more competitive prices, a greater decrease in natural gas contributions to the Policy Compliant Natural Gas Fuel Blend over time than the original TDV model was assumed. We modeled approximately 50 percent of the blend as natural gas by 2050 with hydrogen reaching 7 percent (unchanged from the original DDV value), SNG at about 24 percent, and biogas unchanged from the original TDV value at 19 percent.

Results. We present the results of the water heater analysis in Table 6. This table shows a heat map indicating whether the electric option (green) or natural gas option (red) is more cost effective in each scenario. This provides a visual representation of how the cost-effectiveness of HPWHs change over time by climate zone due to changes in the basic assumptions. Simply put, the inclusion of reasonable maintenance costs for HPWH, shown in Scenario 1 below, makes a fundamental difference in the comparison between gas and electric water heaters. While this basic assumption only flips the cost benefit result in two climate zones, it brings the relationship between the electric and gas water heaters much closer in all of the climate zones.

Changing only the assumptions related to the retail gas prices, shown in Scenario 2 and Scenario 3 below, has a similar impact, although the balance between gas and electric shifts further toward natural gas. Combining the two sets of impacts, as shown in Scenario 4 and Scenario 5 shows that under a realistic set of O&M cost assumptions, and a realistic set of natural gas price assumptions, the gas water heater option is more economic than the HPWH option in most regions.

Table 6. Sensitivity Analysis Results of the Cost-effectiveness of All Scenarios

Climate Zones	Default Scenario	Scenario 1: HPWH Cost Changes Only	Scenario 2: Retail Rate Adjustment Only	Scenario 3: Retail Rate & Gas Cost Only	Scenario 4: Retail Rate & HPWH Cost Changes	Scenario 5: Retail Rate, Gas Cost & HPWH Cost Changes
CZ 1	43.59	0 (no benefits)	0.81	0.76	0 (no benefits)	0 (no benefits)
CZ 2	Undefined (no costs)	1.92	Undefined (no costs)	Undefined (no costs)	0.22	0.09
CZ 3	Undefined (no costs)	1.99	Undefined (no costs)	Undefined (no costs)	0.30	0.17
CZ 4	Undefined (no costs)	2.43	Undefined (no costs)	Undefined (no costs)	0.85	0.72
CZ 5	Undefined (no costs)	1.83	Undefined (no costs)	Undefined (no costs)	0.13	0.01
CZ 6	Undefined (no costs)	2.91	Undefined (no costs)	Undefined (no costs)	1.39	0.84
CZ 7	Undefined (no costs)	2.91	Undefined (no costs)	Undefined (no costs)	1.39	1.28
CZ 8	Undefined (no costs)	3.25	Undefined (no costs)	Undefined (no costs)	1.78	1.67
CZ 9	Undefined (no costs)	3.11	Undefined (no costs)	Undefined (no costs)	1.62	1.51
CZ 10	Undefined (no costs)	2.97	Undefined (no costs)	Undefined (no costs)	1.49	1.37
CZ 11	Undefined (no costs)	2.08	Undefined (no costs)	Undefined (no costs)	0.56	0.44
CZ 12	Undefined (no costs)	2.00	Undefined (no costs)	Undefined (no costs)	0.41	0.29
CZ 13	Undefined (no costs)	2.57	Undefined (no costs)	Undefined (no costs)	1.10	0.98
CZ 14	Undefined (no costs)	1.88	Undefined (no costs)	Undefined (no costs)	0.35	0.23
CZ 15	Undefined (no costs)	3.19	Undefined (no costs)	Undefined (no costs)	2.01	1.92
CZ 16	Undefined (no costs)	0.32	1.03	0.95	0 (no benefits)	0 (no benefits)

Legend: The electric technology (relative to natural gas)

Not Cost-effective — Highly Cost-effective

Appendix B: Natural Gas Prices and the Time Dependent Value of Natural Gas Savings

The overall cost comparisons used in the Proposed 2022 California Energy Code analysis are based on a consumer natural gas price forecast that is, in SoCalGas' judgement, overly pessimistic, representing a much higher than expected retail price of gas, even after consideration of changes in throughput and increases in the volume of low carbon gas in the supply portfolio. This overstatement in retail prices is sufficiently large to change the results of the economic analysis used to justify the proposed changes in the building code. We suggest that the CEC prepare a sensitivity case to examine the results of the Proposed 2022 California Energy Code analysis with a less pessimistic retail gas price forecast. If the sensitivity case results in significant changes to the results of the Proposed 2022 California Energy Code analysis, we request that the CEC conduct a more rigorous analysis of the gas price forecast before finalizing the proposed code changes to the Proposed 2022 California Energy Code.

Specifically, three factors (discussed below) contribute to, a higher than justified natural gas price forecast. The analysis then assumes that resulting high natural gas prices provide additional impetus for more existing gas customers to leave the system than otherwise would be occurring – which create an artificially accelerated price spiral for the natural gas prices used in the Proposed 2022 California Energy Code analysis. Specifically, these three factors are:

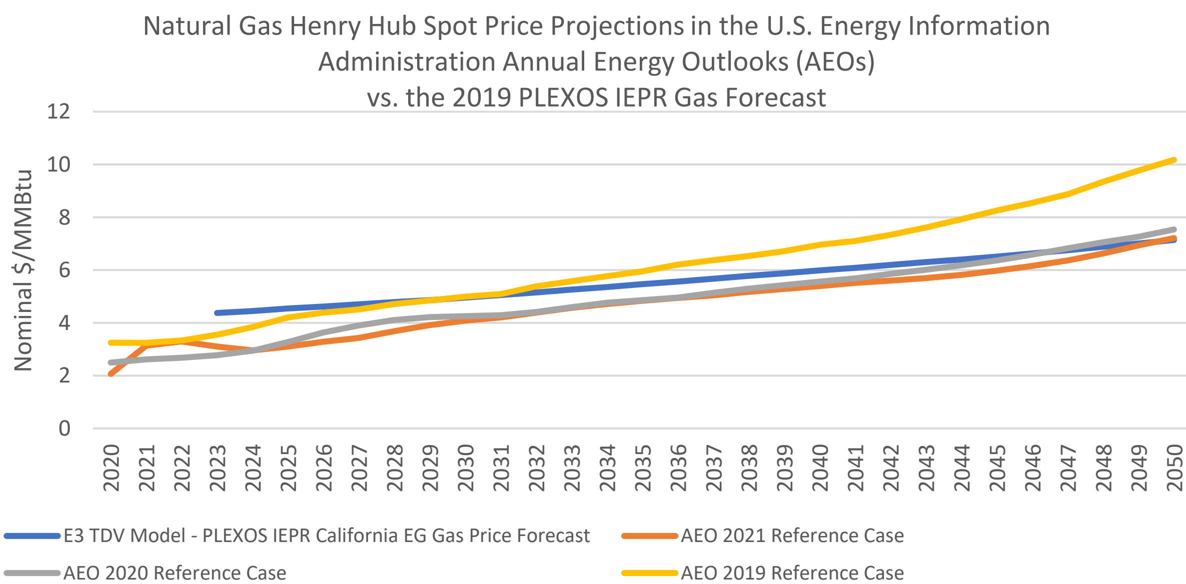
a) The conventional natural gas costs are based on an out-of-date forecast that is substantially higher than current market expectations regarding future natural gas costs. Additionally, the Retail Rate Adjustment included in the Proposed 2022 California Energy Code analysis is based on an overly simplistic assumption about natural gas system costs that leads to a significant overestimate of expected retail natural gas prices.
b) Low carbon gas supply costs, particularly hydrogen costs, are dramatically overestimated relative to current industry expectations.
c) The biogas pricing and availability estimates reflect an overly conservative estimate of the potential for biogas to reduce the carbon content of the gas delivered by utilities.

The combination of these three factors results in a natural gas price forecast that is far less reliable than it could and should be resulting in significantly higher than reasonable reference case costs for the Proposed 2022 California Energy Code analysis. A more realistic assessment of future retail natural gas prices would result in lower prices and lower customer attrition. Similarly, a more realistic assessment of low carbon gas supply costs would lead to additional low carbon gas supplies and similar GHG emissions reductions. Lastly, a lower retail natural gas price could change the cost relationship between natural gas and electricity in many of the new building applications assessed in the Proposed 2022 California Energy Code analysis, leading to different recommendations based on the economic comparison of the natural gas and electric end-use options. If finalized based on sub-optimal data, the proposed code changes and policy changes would cause higher rates, accelerated customer attrition, and avoidable harm to remaining customers.

a. The Natural Gas Commodity Price Forecast is Outdated

SoCalGas believes that the natural gas commodity prices were overestimated due to the use of an outdated natural gas price forecast. For instance, the CEC consultants Energy + Environmental Economics (E3) used the PLEXOS Integrated Energy Policy Report (IEPR) California EG Natural Gas Price Forecast (Nominal $/MMBtu) for 2019. As SoCalGas does not have access to the PLEXOS Forecast for 2019, we compared the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) values for 2019, 2020, and 2021 to estimate the decline in gas price outlook between 2019 and 2021.[23,24] As shown in Figure 3, we found that, on average, the 2019 AEO overestimated natural gas spot price projections (in nominal dollars/MMBtu) at Henry Hub by 20 percent compared to the 2020 AEO, and by 21 percent compared to the updated 2021 AEO. Meanwhile, the 2019 PLEXOS forecast was 11 percent higher on average than the 2020 AEO forecast and 14 percent higher on average than the 2021 AEO forecast. Older gas price projections tend to overestimate prices relative to more recent studies. The commodity price of natural gas is just one of five inputs, but an overestimate of about 20 percent in the commodity price, coupled with a huge increase in the retail adjustment and an unverified "emissions abatement" cost can result is price factors that are unreliable and excessively inflated.

Figure 3. Natural Gas Price Projections Over Time as a Factor in Commodity Costs



The projection of natural gas prices for the Proposed 2022 California Energy Code update reflects a dramatic increase, about 33 percent, in the consumer gas prices relative to the 2019 forecast. More than half of this increase is due to an increase in the retail rate adjustment. The retail rate adjustment by itself represents the single largest component of the potential gas cost accounting for more than 40 percent of the total gas costs. The retail rate adjustment is based on a utility cost allocation reflecting a significant

[23] U.S. Energy Information Administration, Natural Gas Henry Hub Natural Gas Spot Price AEO 2021 and 2020. Available at https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[24] Ibid., Natural Gas Henry Hub Natural Gas Spot Price AEO 2019.

decline in natural gas throughput, in conjunction with a gas utility cost model that assumes growing costs, and no change in costs as throughput declines. According to the CEC report sourced for the TDV analysis, "the base assumption of this study is that the gas system revenue requirement in both mitigation scenarios is equal to that of the reference case."[25] Hence as volumes drop due to improvements in energy efficiency, electrification, and other factors, rates must increase to recover all the unrecovered revenue.

While it is clear that gas utility distribution costs will not decline at the same rate as throughput, there is no analytically based evidence that costs will be unchanged and there is significant evidence that costs will decline, albeit at a slower rate than a decline in throughput. The CEC reports documenting the retail rate forecast provide no sources or documentation to support the conclusion that the gas system revenue requirement would not change with a decline in throughput.[26,27] A recent report from the Haas Energy Institute estimates this relationship at a 0.5 percent decline in revenue for every 1 percent decline in throughput (excluding commodity cost savings).

> *"New customers lead to one-to-one revenue increases, with a ten percent increase in residential customers increasing revenues by ten percent. In contrast, customer losses lead to a less than one-to-one decrease in revenue, with a ten percent decrease in residential customers decreasing revenues by only about five percent. This pattern implies that remaining customers make up about half of the lost revenue through increased rates."*[28]

A more accurate representation of retail rates using the estimated relationship between declining volumes and declining costs would have resulted in substantially lower consumer gas prices. In addition, the use of the Retail Rate Adjustment to capture unrecovered revenue by increasing rates, and then including the impact of the higher rates as a cost in the TDV analysis is inconsistent with economic theory and with economic equity. This component of the Retail Rate Adjustment is simply a transfer cost; a shifting of costs from customers that leave the gas system onto the customers that remain on the gas system. Hence, the customers that are unable or unwilling to pay the costs of converting from natural gas to electricity pay the system costs for the customers that can leave the gas system. And this increase in costs to the customers that can't leave the gas system is used to justify the building code changes that encourage other customers to move off the gas system. Despite the inclusion of the retail rate adjustment in the marginal natural gas costs, there are no true societal cost savings associated with this element of the TDVs. Figure 4 shows the magnitude of overestimation in the CEC's assumptions with the Retail Rate Adjustment; it

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[25] Energy and Environmental Economics, Inc. and University of California, Irvine, *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*, CEC-500-2019-055-F, April 2020, at 49. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf#:~:text=The%20Challenge%20of%20Retail%20Gas%20in%20California%E2%80%99s%20Low-Carbon,Environmental%20Economics%20and%20the%20University%20of%20California%2C%20Irvine.

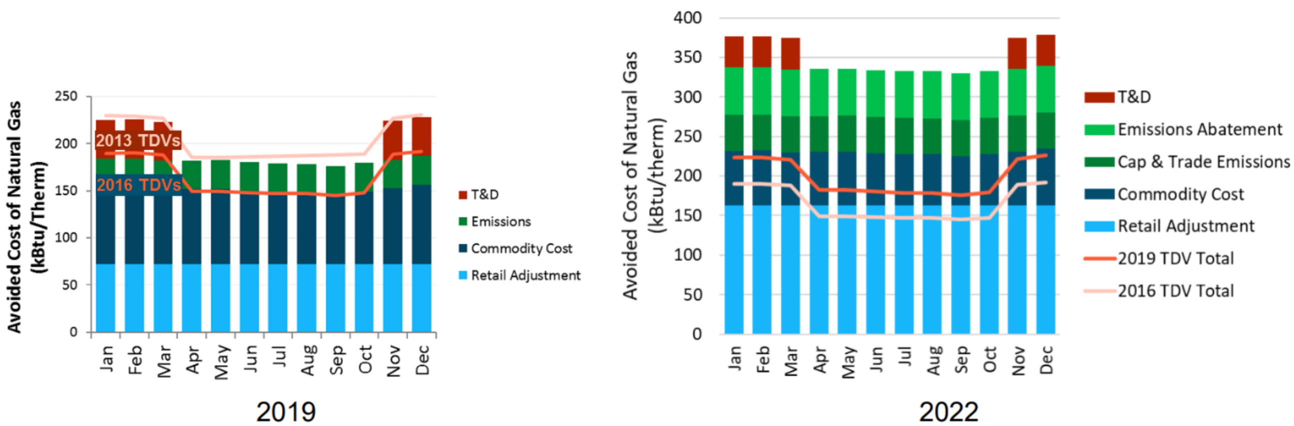
[26] Ibid.

[27] NORESCO and Energy and Environmental Economics, Inc., *TN 237776: Nonresidential PV and Battery Storage Measure Proposal*, Docket 21-BSTD-01, 11 May 2021, at 59. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=237776&DocumentContentId=71014.

[28] Lucas Davis and Catherine Hausman, *Who Will Pay for Legacy Utility Costs?*, Energy Institute at Haas, Energy Institute WP 317, June 2021, at 2. Available at https://haas.berkeley.edu/wp-content/uploads/WP317.pdf.

goes from about $70 of avoided cost of natural gas (kBtu/Therm) in the 2019 forecast to $160 of avoided cost of natural gas (kBtu/Therm), which is an increase of about 225 percent.

Figure 4. 2019 vs 2022 Natural Gas TDV



b. Low Carbon Gas Supply Costs are Dramatically Overstated

The CEC assessment of natural gas costs included in the TDV analysis is based on several assumptions related to the cost of low carbon gas, which according to alternative and more recent analysis, present a very pessimistic view of the future that is inconsistent with industry expectations. Specifically, the gas price used in the Proposed 2022 California Energy Code cost-benefit analysis is based on the marginal cost of hydrogen, which is estimated to be $45.29/MMBtu in 2031 and declining to $33.42/MMBtu by 2050.[29] These estimates are described as "optimistic" estimates of future technology costs by E3 and the University of California, Irvine (UCI) in their analysis for the CEC, *The Challenge of Retail Gas in California's Low-Carbon Future*, published April 2020.[30] However, in June 2020, E3 published an analysis for Mitsubishi Hitachi Power Systems Americas, Inc. (MHPS) and Magnum Development, LLC., *Hydrogen Opportunities in a Low-Carbon Future*, that reflects much lower hydrogen cost estimates.[31]

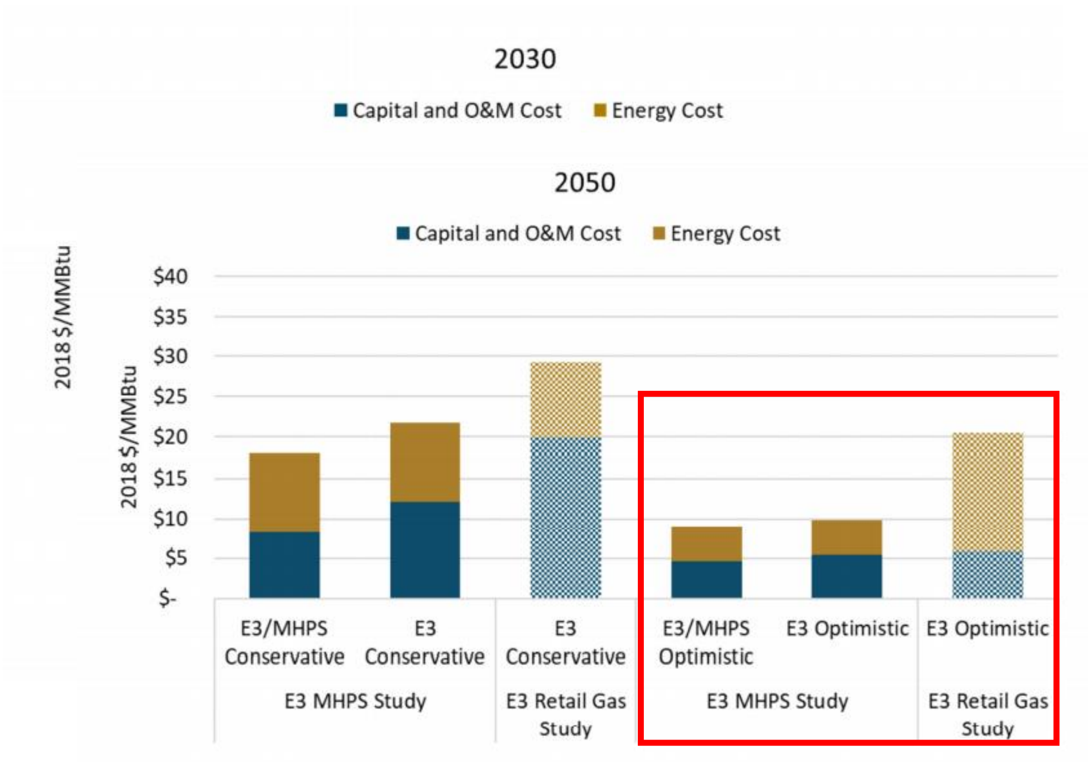
E3's hydrogen price estimates changed significantly between the April 2020 analysis and the June 2020 analysis. Conservative and optimistic energy, capital, and O&M hydrogen costs in the MHPS analysis were much lower than those estimates for the CEC analysis in both 2030 and 2050 (the CEC's E3 Retail Gas Study 2050 "optimistic" costs are greater that two times the cost of an E3's MHPS "optimistic" case released within a few months of each other). In some cases, the MHPS analysis also showed a greater potential for hydrogen price declines over time than was demonstrated in the analysis for the CEC. Further,

[29] Hydrogen prices in the TDV are reported in nominal dollars, based on a 2 percent per year inflation factor. As such, hydrogen prices in real 2020 dollars would be $36.4 per MMbtu in 2031, falling to $17.06 in 2050.
[30] Energy and Environmental Economics, Inc. and University of California, Irvine, *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*.
[31] Energy and Environmental Economics, Inc., *Hydrogen Opportunities in a Low-Carbon Future*, June 2020. Available at https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.

the MHPS Study attributes these differences to fundamentally different but reasonable assumptions. As part of the MHPS Study, E3 compared the two studies' hydrogen price estimates (shown in Figure 5). Ultimately, the challenge is that there is more uncertainty in hydrogen prices than is being acknowledged in the Retail Gas study.

While the contemporaneous E3 study[32] did not reflect the CEC views and is based on a different set of assumptions developed for a different client with a different perspective on the market, SoCalGas believes that at a minimum, the CEC analysis should recognize variations among hydrogen price forecasts and that used in the TDV (suggesting that it reflects a somewhat conservative projection of future costs). As such, assessment and consideration of additional scenarios more in line with current industry expectations would enhance the efficacy and accuracy of the analysis. For instance, during the same time period, other public reports[33] projected that delivered hydrogen costs would fall to $15/MMBtu by 2030 and to $7.4/MMBtu by 2050, if a significant public investment in hydrogen technology is made. Furthermore, the U.S. Department of Energy (DOE) recently announced a "Hydrogen Energy Earthshot" program that presents a hydrogen production cost target of about $7.4/MMBtu by 2030.[34]

Figure 5. E3's Comparison of the Hydrogen Price Estimates in the MHPS Study (June 2020) and in the CEC Retail Gas Study (April 2020)[35]



[32] Ibid.
[33] Bloomberg NEF, *Hydrogen Economy Outlook*, 30 March 2020. Available at https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf.
[34] U.S. Department of Energy, *Secretary Granholm Launches Hydrogen Energy Earthshot to Accelerate Breakthroughs Toward a Net-Zero Economy*.
[35] Energy and Environmental Economics, Inc., *Hydrogen Opportunities in a Low-Carbon Future*, at 72.

Since hydrogen is a major input to the production of SNG, the costs of SNG also appear to be significantly overstated, as the reduction in hydrogen costs will also result in a similar reduction in SNG costs. The CEC estimates that by 2050 SNG will cost between $10/MMBtu (from organic waste sources of carbon, "bio-CO_2") and $21/MMBtu (direct air capture) more to produce than hydrogen in their optimistic case.[36] The technology advancements expected to drive down hydrogen costs should be expected to reduce the cost difference between hydrogen and SNG. This includes co-production of SNG and renewable natural gas (RNG) as well as other cost reduction strategies. Hence, an alternative technology case for low carbon gas would have the cost of hydrogen at below $10/MMBtu, while SNG costs would be between $15/MMBtu and $25/MMBtu. While there is no guarantee that hydrogen costs will reach the DOE "Hydrogen Earthshot" program target, it is informative to the impacted stakeholders and public as it is representative of the level of scale up effort that successfully and dramatically decreased renewable electricity production costs. The nascent state of low carbon gas technology, and at a minimum, the potential for much lower cost low and no carbon gas should be addressed in the CEC analysis.

c. Conservative Estimates of Biogas Potential

The CEC analysis assumes relatively limited access to biogas resources for residential and commercial gas customers in California. In *the Challenge of Retail Gas in California's Low-Carbon Future* (Retail Gas) Report,[37] E3 referenced standard biomass studies like the 2016 DOE Billion-Ton Report[38] when calculating the RNG feedstock potential. Yet, E3 took a more conservative approach and excluded purpose-grown energy crops from the estimate of biomass resource potential. As a result, E3 estimates of California's biomass resources/ population-share of U.S. biomass resource base (43 million dry tons of biomass per year by 2040) reflect a somewhat conservative estimate of biofuel potential.

E3 then assumed that biomass resources available for residential and commercial customers will be limited relative to the estimate of potential. E3 notes in Appendix D of the Retail Gas Report that:

> *"the biomass supply potential assessed here focuses on economic or technical potentials, not gross potentials. The gross potential is the total quantity of raw biomass generated each year. The technical potential is the quantity that could be physically recovered. The economic potential is the quantity that can be utilized economically, which depends somewhat on the value of the resulting fuels and the availability of alternatives."*[39]

While E3 reduced the availability of biomass for biogas, the report does not detail how this reduction was calculated and/or whether the reduction was reasonable. From the documentation provided, how the report

[36] Energy and Environmental Economics, Inc. and University of California, Irvine, *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use*, at 24-25.
[37] Ibid.
[38] U.S. Department of Energy, *2016 Billion-Ton Report*, July 16. Available at https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.
[39] Energy and Environmental Economics, Inc. and University of California, Irvine, *The Challenge of Retail Gas in California's Low-Carbon Future: Appendices A-G*, CEC-500-2019-055-AP-G, April 2020, at Appendix D-16. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdf.

processed and reduced the resource base between these scales of biomass potential down to the RNG available for end uses is not clear. This includes the basis for the modeling decisions that reduced the amount of biomass available for RNG in the Retail Gas Report's economic potential such that "much of biomass [was] converted to liquid fuels." The report notes that the 43 million dry tons of biomass, if used entirely for biomethane, equates to 635 trillion Btu annually by 2040. It is unclear if the assumptions guiding the economic potential assessment were justifiable. Consequently, the analysis is not replicable thereby raising questions of its reliability.

The TDV analysis includes a note that E3 "[assumed] that biogas is supply-limited, so incremental gas consumption will not be able to be met by incremental biogas supply."[40] Biogas is included in the TDV supply mix, but it is possible that more would be available to the utility market, either due to higher overall supply or based on a higher percentage of available RNG used for utility supply.

In addition, the E3 analysis of gas prices for the CEC used marginal or market clearing prices for RNG.[41] This assumption is based on an economic model similar to current conventional natural gas purchasing practices where purchases are made based on short term market clearing prices. This business model is unlikely to predominate in the biofuels market, where utilities are currently making long term fixed price agreements to purchase biofuels from individual producers, rather than making short term purchases at market clearing prices.

Assuming that utilities are buying on the margin also leaves no room for different price streams based on the impact of different incentive structures on RNG from different sources and for different end-uses. As a result, the assumption that utilities pay a single market-clearing price for all biofuel purchased likely overestimates the reasonably expected biofuel and SNG costs to utilities. Likewise, there appears to be an inherent inconsistency with the assumption that utilities will be excluded from significant sources of biofuels due to being a lower-value user.

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[40] California Energy Commission, *TDV 2022 Update Model.* Available at https://www.energy.ca.gov/files/tdv-2022-update-model.

[41] The TDV analysis assumed 0 percent penetration of SNG and therefore SNG did not contribute to total gas costs or carbon reductions. We presume that SNG was excluded due to assumed costs higher than other emissions reduction measures.

Appendix C: A Look at the Avoided Cost of Generation

The "Final 2022 TDV Methodology" report[42] sets the avoided capacity cost beyond 2030 at the fixed operations and maintenance of CCGT resources. This is based on the assertion that the diminishing electricity load carrying capacity (ELCC) of storage and solar ***requires*** existing resources to provide firm capacity. The report states that RESOLVE modeling was conducted and that capacity prices from RESOLVE are utilized for 2030. We respectfully request the CEC to please provide capacity prices out of RESOLVE for the forecast period and some context as to why there was deviation from RESOLVE capacity prices for any year after 2030.

Additionally, the "Final 2022 TDV Methodology" report sets the avoided capacity cost beyond 2030 at the fixed operations and maintenance of CCGT resources. This is based on the argument that the diminishing ELCC of storage and solar ***renders*** existing resources available to provide firm capacity. We were unable to find further evidence that the existing resources in the system are sufficient to meet the growing demand from electrification and in fact, our internal modeling suggests the converse: the more load is electrified, the more peak day gas demand to support electric reliability and resiliency increases. We therefore respectfully request that the CEC provide the data necessary to demonstrate that the installed resources and new additions are sufficient to meet resource adequacy requirement, accounting for the declining ELCC of renewable and storage resources and that no additional firm capacity will be required to meet the increased demand due to electrification.

In addition, it seems likely that the gas costs associated with the operation of the CCGT resources are understated. The cost of the CCGT assets appears to be constant in real terms after 2031.[43] However, this assumption is inconsistent with the need to hold firm gas pipeline service to the generating stations in an environment where throughput on the gas system, and throughput at the generating stations is expected to decline due to growth in renewable power. The plants will need to maintain firm pipeline service to ensure the availability of gas when needed. The costs of the firm service will be spread over a declining load, resulting in higher costs per unit of power generated, and higher marginal capacity costs associated with these units. In the best case, this will lead to current pipeline capacity costs being spread over a smaller generation base, leading to an increase in per kWh costs. In the worst case, pipeline costs will need to increase substantially as the demand for gas in the residential and commercial sector declines, putting more pressure on power generation customers to cover the cost of the pipeline system rather than facing termination of the pipeline service.

[42] California Energy Commission, *TN 233257: Final 2022 TDV Methodology Report*, Docket 19-BSTD-03. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=233257&DocumentContentId=65743.
[43] Ibid.

Appendix D: Proposed Requirements for Kitchen Exhaust Systems and Range Hood Ventilation

Cooking is a well-recognized source of particulate matter (PM) in homes. PM is primarily emitted from the cooking process (*i.e.*, frying, sautéing, toasting, etc.) and the emissions are similar whether the energy source of the stove is gas or electric. Furthermore, cooking is not the only source of PM and nitrogen dioxide (NO_2) in homes. Outdoor (ambient) air and other indoor sources also contribute to indoor air concentrations of these air pollutants. Over the years, there have been notable changes to indoor concentrations of $PM_{2.5}$ and NO_2. First, outdoor air concentrations of $PM_{2.5}$ and NOx (including NO_2) have decreased, due in part to regulations of ambient air quality.[44,45] Second, buildings have gotten more energy efficient, with an accompanying tighter building envelope, which has kept outdoor pollution from infiltrating into buildings.[46] Tighter building envelopes also can trap air pollutants indoor, hence the importance of ventilation.

Additionally, building codes and other factors have improved indoor ventilation. Indoor ventilation is regarded as a key factor in mitigating emissions associated with cooking. Many ranges now include a hood to direct the emissions away from the kitchen. California's Title 24 Building Standards have required mechanical ventilation in new homes since 2008 (effective January 1, 2010) to decrease cooking-related exposures. Further, gas stoves with pilot lights have not been manufactured for over a decade. Today's gas stoves are more efficient, have electronic starters, and emit less NO_2 than older gas stoves with gas-fed pilot lights. Significantly, studies demonstrate that residents' exposures to NO_2 in households using gas stoves with electronic starters are statistically similar to exposures in households with electric stoves (*i.e.*, only ~5 parts per billion [ppb] higher for NO_2). [47,48,49]

[44] U.S. Environmental Protection Agency, *Air Trends: Particulate Matter ($PM_{2.5}$) Trends*, Web, 21 May 2021. Available at https://www.epa.gov/air-trends/particulate-matter-pm25-trends.

[45] U.S. Environmental Protection Agency, *Air Trends: Nitrogen Dioxide* Trends, Web, 21 May 2021. Available at https://www.epa.gov/air-trends/nitrogen-dioxide-trends.

[46] Institute of Medicine, *Climate Change, the Indoor Environment, and Health*, Washington, DC: The National Academies Press, 2011. Available at https://doi.org/10.17226/13115.

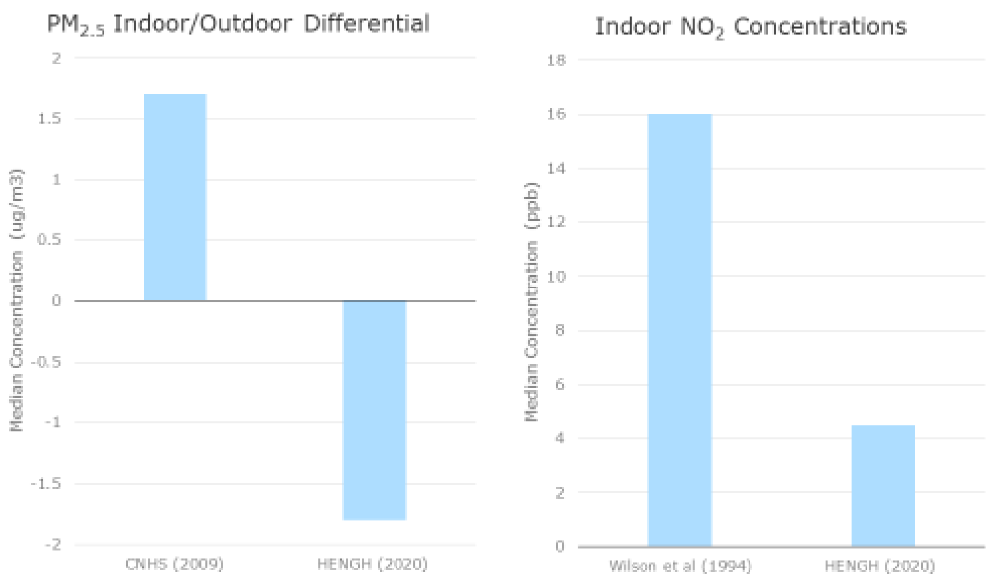
[47] Gary J. Raw, Sara K. D. Coward, Veronica M. Brown, and Derrick R. Crump, *Exposure to air pollutants in English homes*, J Expo Anal Environ Epidemiol, 14 (Suppl. S1): S85–S94, 2004. Available at doi: 10.1038/sj.jea.7500363.

[48] Óscar García-Algar, Meritxell Zapater, Cecilia Figueroa, Oriol Vall, Xavier Basagaña, Jordi Sunyer, Assumpcio Freixa, X avier Guardino, and Simona Pichini, *Sources and Concentrations of Indoor Nitrogen Dioxide in Barcelona, Spain*, Journal of Environmental Science and Health, Part A 56:2: 1312-1317, 22 February 2012. Available at https://www.tandfonline.com/doi/citedby/10.1080/10473289.2003.10466297?scroll=top&needAccess=true.

[49] Kiyoung Lee, Wonho Yang, and Neville D. Bofinger, *Impact of microenvironmental nitrogen dioxide concentrations on personal exposures in Australia*, Journal of the Air and Waste Management Association, 50: 1739-1744, 2000. Available at https://www.tandfonline.com/doi/pdf/10.1080/10473289.2000.10464212.

Finally, as illustrated below in Figure 6,[50,51,52] indoor $PM_{2.5}$ and NO_2 concentrations have been decreasing. Thus, residential exposures to air pollutants from gas appliances are decreasing and are much lower now than 20 years ago. $PM_{2.5}$ emission reduction drivers are lower outdoor $PM_{2.5}$ emissions, high efficiency air filters in central forced air systems and mechanical ventilation systems. NO_2 emission reduction drivers are mechanical ventilation and lower outdoor NO_2 emissions.

Figure 6: Indoor $PM_{2.5}$ and NO_2



Likewise, ventilation is a useful tool to improve indoor air quality, not only for $PM_{2.5}$ and NO_2, but for other indoor pollutants. In fact, whole house ventilation is already required under the energy code. The proposed code changes add rating metrics for range hood capture efficiency. As shown in Table 150.0-G of the Draft 2022 Energy Code Express Terms (below), the proposed hood capture efficiencies for electric stoves ranged from 50 percent to 65 percent and for natural gas stoves from 70 percent to 85 percent, depending on the size of the dwelling unit, in order to avoid high levels of NO_2 (based on a 1-hour standard) and $PM_{2.5}$ (based on a 24-hour standard).

[50] California Energy Commission, *Ventilation and Indoor Air Quality in New Homes*, CEC-500-2009-085, November 2009. Available at https://www.acac.org/forms/rclibrary/caventilation.pdf.
[51] Yang Kim, Brennen Less, Brett Singer, Wanyu R. Chan, and Iain Walker, *Ventilation and Indoor Air Quality in New California Homes with Gas Appliances and Mechanical Ventilation*.
[52] AL Wilson, SD Colome, Y Tian, and CA Garrison, *Formaldehyde and Nitrogen Dioxide Concentrations Inside and Outside of Homes in California*, A&WMA 94-WP90.01, 1994.

Table 7. Kitchen Range Hood Airflow Rates (cfm) and ASTM E3087 Capture Efficiency (CE) Ratings According to Dwelling Unit Floor Area and Kitchen Range Fuel Type

Dwelling Unit Floor Area (ft^2)	Hood Over Electric Range	Hood Over Natural Gas Range
>1500	50% CE or 110 cfm	70% CE or 180 cfm
>1000 - 1500	50% CE or 110 cfm	80% CE or 250 cfm
750 - 1000	55% CE or 130 cfm	85% CE or 280 cfm
<750	65% CE or 160 cfm	85% CE or 280 cfm

We understand that these capture efficiencies were derived from experiments and modeling conducted by the LBNL. There are a lot of variabilities involved with cooking itself and among the experiments, especially $PM_{2.5}$ associated with cooking. Therefore, we strongly recommend that a single capture efficiency standard (the more stringent of the two) for each dwelling unit size regardless of fuel source will be in the public interest as well as decrease all indoor pollutants to a greater extent.

Despite the health benefits that ventilation offers, a survey conducted by the LBNL[53] shows that many people do not use their range hoods because they think the hood is not needed, simply forget it is there, or find it is too noisy. We suggest for the CEC to consider range hoods that turn on automatically when the stove is turned on. This strategy has been used in Japan[54] and has been found to be effective.

[53] Yang Kim, Brennen Less, Brett Singer, Wanyu R. Chan, and Iain Walker, *Ventilation and Indoor Air Quality in New California Homes with Gas Appliances and Mechanical Ventilation*.
[54] *See* Presentation by Kazukiyo Kumagai of the California Department of Public Health at the CEC Workshop on September 30, 2020, Docket: 21-BSTD-03.

Appendix E: Risks Associated with Battery Storage Assumptions

The data sources used by the CEC for estimating the costs of the residential energy storage are reputable and appear reasonable. However, residential energy storage lacks manufacturers and historical data to estimate costs as accurately as utility storage. Therefore, the risks and data gaps associated with availability, reliability, and operations and maintenance should be considered in addition to energy storage costs.

Represented in Table 9, the CEC forecasted the following capital expenditure (CAPEX) costs for battery energy storage systems (BESS). Two reputable sources were used to forecast the 2023 BESS CAPEX costs in the below table. However, the sources have limited data for residential energy storage. For example, one of the two source's estimated costs for residential energy storage are limited to 2 use cases in Hawaii and Germany (both 6kW/25kWh), not California.[55] The other source's cost projections were based on large scale utility battery storage system cost trends and limited to estimates/quotes from a single residential battery storage system manufacturer, Tesla.[56] This is due to the scarce number of battery storage systems available for residential installations (smaller than 800kWh). Currently, most available battery storage systems are for large scale utilities. Therefore, it is believed that the quotes provided by Tesla are accurate for 2021, but that their large influence within the energy code pre-rulemaking present the following risks:

- Tesla may charge a higher price than what would otherwise be available in a more competitive market. Therefore, projected energy storage costs could be inaccurate.
- Tesla may not have the ability to meet future demands as the primary manufacturer of residential energy storage. This could delay projects and hinder the cost effectiveness of PV + storage.

Table 8. Incremental First Costs for Battery Energy Storage System[57]

Battery Size (kW, kWh)	CAPEX (2020$/kWh)	CAPEX (2023$/kWh)
10 kW, 40 kWh	$760	$807
25 kW, 100 kWh	$754	$800
50 kW, 200 kWh	$743	$789
75 kW, 300 kWh	$733	$778
100 kW, 400 kWh	$723	$767
500 kW, 2000 kWh	$599	$636

[55] Lazard, *Lazard's Levelized Cost of Storage Analysis - Version 5.0*, November 2019, at 31 and 36. Available at https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

[56] California Energy Commission, *TN 235137: Noresco Slides on PV and Storage Cost Presented on October 2020*, Docket 19-BSTD-03, 8 October 2020. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=235137&DocumentContentId=68017.

[57] NORESCO and Energy and Environmental Economics, Inc., *TN 237776: Nonresidential PV and Battery Storage Measure Proposal*, Docket 21-BSTD-01, 11 May 2021, at 63. Available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=237776&DocumentContentId=71014.

Additionally, the CEC mentioned the use of a “cell replacement” strategy within its lifetime incremental operations and maintenance costs. However, “cell replacement” is not defined within the CEC documentation. Therefore, it is assumed that “cell replacement” requires removing all the existing and/or old batteries from an existing energy storage enclosure and adding new batteries in their place. This may be the most cost-effective solution for maintaining the capacity of the system because it requires the shortest bill of materials, compared to augmentations. However, this solution is highly speculative and not without risk. For example, it is unclear if the following was considered when estimating battery replacement costs:

- Will the warranty of the energy storage enclosure be viable for up to 30 years? For example, Tesla’s Powerwall has a limited warranty of 10 years.[58]
- Will the form factor of the energy storage container be capable of integrating future batteries? Future batteries may have different voltage levels and form factors.
- If the energy storage integrator/manufacturer is no longer in business, how will future O&M and replacements be performed? Can batteries from another manufacturer be integrated into a competitor’s enclosure?

[58] Tesla, *Service & Warranty*, Web, 2021. Available at https://www.tesla.com/support/energy/solar-panels/learn/solar-service-warranty.