DOCKETED	
Docket Number:	23-IEPR-03
Project Title:	Electricity and Gas Demand Forecast
TN #:	253460
Document Title:	PG&E Comments RE IEPR Workshop on Load Modifier Scenario Results
Description:	N/A
Filer:	System
Organization:	PG&E
Submitter Role:	Public
Submission Date:	12/1/2023 2:21:07 PM
Docketed Date:	12/1/2023

Comment Received From: Josh Harmon
Submitted On: 12/1/2023
Docket Number: 23-IEPR-03

PG&E Comments RE IEPR Workshop on Load Modifier Scenario Results

Additional submitted attachment is included below.

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December 1, 2023

California Energy Commission
Docket Number 23-IEPR-03
715 P Street
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RE: CEC IEPR Commissioner Workshop on Load Modifier Scenario Results

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the California Energy Commission's (CEC) IEPR Workshop held on November 15, 2023.

PG&E commends the CEC on its robust analysis of the variables that will shape future electricity demand. In particular, PG&E appreciates the effort and resources the CEC invested in making meaningful advancements to all its load modifier forecasting methodologies. PG&E also appreciates the CEC's extending of the forecast horizon to 2040.

PG&E offers six general comments on the workshop that cut across multiple load modifiers as well as thematic comments that correspond to this year's focus for the IEPR. While some have been carried forward from PG&E's previous comment letter on the August 18 IEPR Workshop due to continued relevance, PG&E has also included new feedback in this letter. To aid the CEC's review, we have underlined new comments.

First, PG&E recommends that the CEC examine whether the load modifier scenario assumptions are sufficiently different in the Planning Forecast and Local Reliability Scenario to produce scenarios with meaningfully different results.

PG&E's understanding is that the difference between the Planning Forecast and Local Reliability Scenario is the selection of the Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Fuel Substitution (AAFS) scenarios. Assumptions for all other components will all be the same in both the Planning Forecast and Local Reliability Scenario.[1]

Based on the workshop presentations, the electricity impacts of AAFS 3 (used in the Planning Forecast), and AAFS 4 (used in the Local Reliability Scenario)—which were highly different in the 2022 California Energy Demand Forecast—appear to be relatively similar, especially in years 2030-onward. Consequently, our understanding is that the differences between AAEE 2 (used in the Local Reliability

[1] Other components include economic, demographic, and price; behind-the-meter solar; behind-the-meter storage; and transportation electrification.

scenario) and AAEE 3 (used in the Planning Forecast) will be the primary differences between the Local Reliability Scenario and the Planning Forecast.

Given the high levels of uncertainty associated with all DER adoption, impacts of emerging policy, and the resulting impacts on electricity demand, we believe it is valuable to have Planning Scenarios and Local Reliability Scenarios that are sufficiently different to depict the range of uncertainty. To that end, PG&E recommends that the CEC consider opportunities to represent more of that uncertainty in the Planning Forecast and Local Reliability Scenarios. Potential opportunities include, for example, changing assumptions in AAFS 3 and AAFS 4 so the results are more materially different, selecting AAFS 5 or AAFS 6 for the Local Reliability Scenario, or by using different scenarios for the other forecast components (e.g., economic, demographic, and price; behind-the-meter solar; behind-the-meter storage, and transportation electrification). Among these opportunities, PG&E specifically recommends the CEC evaluate how sensitive AAFS scenario results are to assumptions about appliance lifetimes and to consider varying these assumptions across scenarios.

Second, PG&E would appreciate the opportunity to access the CEC's models and data.

PG&E is especially interested in the CEC's data and models concerning Behind the Meter (BTM) Self Generation, BTM Storage, Electric Vehicles, Additional Achievable Fuel Substitution, and Committed and Additional Achievable Energy Efficiency—some of which the workshop presentations indicate have undergone substantial revisions recently. Having access to these models and data—for example, via the CEC's Planning Library—would enhance our understanding of how the CEC now performs their forecasting and would enable us to provide more detailed feedback on the modeling assumptions. As PG&E has mentioned in the past, we find the CEC's Planning Library to be extremely useful and support its expanded use.

Third, PG&E recommends the CEC expand the scope of the IEPR electricity forecasting to include potential new large industrial loads such as industrial electrification, data centers, cryptocurrency miners, and hydrogen production.

PG&E recognizes that forecasting these new industrial loads is challenging and would likely require substantial investment of resources; however, there is reasonable likelihood that these topics could have major impacts on a decarbonized energy system in the United States and California. Some of these new industrial loads are flexible and could play a meaningful role in improving the efficiency and reliability of California's energy resources and grid while decarbonizing our energy systems.

In the specific case of hydrogen production, such a forecast would provide a valuable, more comprehensive insight into how hard-to-electrify industrial customers and hydrogen fuel cell transportation — especially of medium- and heavy-duty vehicles, for which the CEC already forecasts vehicle population — will affect electricity demands.

Fourth, PG&E recommends that the CEC investigate the sensitivity of load modifiers' performance to temperature.

Based on the August 18 IEPR workshop presentation, PG&E understands the CEC's intention to consider the efficiency of BTM PV at elevated temperatures. In that same vein, PG&E recommends the CEC also consider how the efficiency of other load modifiers vary by temperature. For example, the efficiency of both heat pumps and electric vehicles decreases with extreme temperatures. These temperature sensitivities are especially pertinent on winter peak and summer peak days—which typically coincide with extreme temperature events—and the 1-in-N electricity peak analyses.

Fifth, PG&E would appreciate the opportunity to review draft hourly load impact results.

PG&E appreciated the presentations that demonstrated some preliminary hourly load impact data for electric vehicles and BTM storage and we understand that additional hourly load impact results will be presented at the December 6 IEPR workshop. The PG&E System peak forecast—which is based on the hourly load impacts—is a critically important output of the IEPR forecast. Consequently, PG&E would appreciate greater opportunities to understand how hourly impacts are modeled in the CEC forecast. To that end, for future IEPR cycles, PG&E would like to request an opportunity to review and discuss preliminary hourly impacts earlier in the forecasting cycle, for example via a Demand Analysis Working Group meeting, to facilitate PG&E's understanding of the CEC's hourly load forecasts prior to that work being presented to the Commissioners.

Sixth, PG&E recommends the CEC study the potential impact of load flexibility to manage peak demand.

The ability for DERs to shift load represents a substantial, albeit highly uncertain opportunity to manage the growth of peak demand, to the benefit of the grid and all customers. PG&E expects that a material share of customers will use the flexibility to shift load—especially via electric vehicles and heat pump water heaters—to reduce their energy bills. In future cycles of the IEPR forecast, PG&E recommends that the CEC consider how load flexibility might change the hourly impact of load modifiers relative to current assumptions in the IEPR forecast. Given the CEC's expertise with existing Additional Achievable modeling framework—already applied to energy efficiency, fuel substation, and transportation electrification—PG&E recommends the CEC consider if it would be appropriate to apply the Additional Achievable framework to load flexibility, for example, to create an Additional Achievable Load Flexibility scenario.

PG&E also provides the below comments on this year's IEPR thematic focus areas.

Behind-the-Meter Self Generation Forecast Draft Results

PG&E supports the methodological changes outlined in the workshop. CEC's contracting with NREL to update their BTM PV and BTM Storage modeling appears to have been a valuable contribution to California's forecasting tools.

PG&E considers the BTM PV and BTM Storage adoption forecasts to be reasonable scenarios. Nevertheless, we also acknowledge that there is substantial uncertainty around the size of the BTM PV and BTM storage market size and adoption dynamics. Consequently, we recommend the CEC consider a range of scenarios that reflect that uncertainty in the Planning Forecast and Local Reliability Scenario, rather than using the same adoption forecast for both the Planning Forecast and Local Reliability Scenario.

Additionally, PG&E recommends CEC consider how the sizing of BTM PV and BTM Storage systems may change in the future as a consequence of the electrification forecasted in the Planning Forecast and Local Reliability Scenario. For example, compared to a mixed-fuel home with two internal combustion vehicles, as is typical for California homes today, a fully electric home with two electric vehicles is expected to have greater than double the electricity consumption. Consequently, PG&E would expect that typical BTM PV system sizes would also trend larger to at least partially offset the greater electricity demand arising from transportation and building electrification. PG&E expects such a change would result in larger BTM PV capacity additions than what the CEC is currently forecasting.

Regarding the CEC's BTM Storage load shapes, PG&E is supportive of the methodology and preliminary results presented in the workshop. In particular, PG&E expects that BTM storage will have substantial impact by charging during mid-day hours—when there is usually low-cost solar energy--and discharging during higher price hours in the vicinity of hour ending 20.

Additional Achievable Energy Efficiency (AAEE) & Additional Achievable Fuel Substitution (AAFS) Results

PG&E appreciates how rapidly the CEC has worked to substantially advance the AAFS forecast in recent years. AAFS is a particularly challenging topic to forecast because of the dearth of observed adoption data, the variability of impacts across California due to the complex diversity of building types, climates, and technologies, and the rapidly changing policy landscape. To that end, PG&E appreciates how the CEC has strategically crafted a range of valuable AAFS scenarios that effectively span and address key forecasting uncertainties, especially the impact of new policies from the California Air Resource Board and regional air districts such as the Bay Area Air Quality Management District.

Incorporating Targeted/Zonal Electrification and Gas Decommissioning Efforts into AAFS

Traditionally, fuel substitution forecasts have focused on replacement of space and water heating systems. In future IEPR forecast cycles, PG&E would be interested in seeing the CEC explore an AAFS scenario that contemplates additional fuel substitution due to electrification of specific "zones" where a gas utility would have otherwise invested to repair or replace an existing gas pipeline.

As an example, zonal electrification could be incorporated into AAFS 5 and 6, with AAFS 6 assuming zonal electrification efforts begin in 2030 and AAFS 5 assuming zonal electrification efforts begin in 2040. As Energy and Environmental Economics, Inc (E3) highlights in its report The Challenge of Retail Gas in California's Low-Carbon Future, "a managed gas transition would likely require some amount of… zonal electrification to enable a reduction in the gas distribution infrastructure. Without a managed gas transition and without any effort to target electrification it would be difficult to reduce the size or scale of gas system investments and costs.[2]"

To maintain safety and reliability, the natural gas system comes with necessary operations and maintenance needs, the costs for which are approved by the California Public Utilities Commission (CPUC) in PG&E's General Rate Case. Without strategies such as full building decarbonization or zonal electrification, the gas system and its associated maintenance costs will remain relatively fixed while customer demand for gas falls. This will create an unsustainable trend in which those relatively fixed maintenance and reliability costs are spread over a smaller base of customers, leading to potential increases in gas costs. If a customer or subset of customers were to fully electrify instead, the infrastructure associated with that portion of the gas system could be retired, potentially leading to a more equitable decarbonization transition.

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[2] The Challenge of Retail Gas in California's Low-Carbon Future (ethree.com)

Incorporating Zero-Emission Appliance Standards to AAFS

PG&E is unable to evaluate the reasonableness of the zero-emission appliance standards assumptions used in the Planning Forecast and the Local Reliability Scenario due to the limited publicly-available space and water heating appliance replacement data and estimates of the impact of zero-emission appliance standards on gas appliance repair rates. Specifically, zero-emission appliance standards may have an impact on gas appliance lifespan if some customers elect to extend their gas appliance's useful life through repair rather than replace it with an electric appliance. There are many sources of uncertainty as compliance will depend on complementary policies and programs, (local, state, national), as well as compliance improvement and enforcement. If public information, including permit data, was used for these assumptions, PG&E encourages the CEC to include this in future presentations.

Separately, PG&E would like additional detail on the assumption that all newly constructed buildings will contain 100% zero-emission appliances starting in 2026 and 2029 for the residential and commercial sectors, respectively. If the assumptions reflect expectations of outcomes for the 2025 and 2028 Energy Code rulemakings, PG&E notes that it may be premature to assume all newly constructed buildings will immediately be all-electric. Based on the content shared to date in the 2025 Energy Code update pre-rulemaking workshops, specifically the "2025 Energy Code Heat Pump Baselines, Solar Photovoltaic and Energy Storage Requirements" event held on August 24, 2023[3] and the subsequent release of the Express Terms, it is unlikely that all permitted residential new construction in 2026, 2027 and 2028 will be compelled to be all-electric via the Energy Code.

PG&E also notes that on November 3, 2023, CARB introduced a proposed amendment to Part 11 of the California building code requiring that all newly constructed residential buildings be designed and constructed as "zero-emission" as of January 1, 2026.[4] It is expected that Housing Community Development (HCD) will review this code change proposal. If it receives HCD support, it will move toward adoption through the Building Standards Commission. If adopted, this code change would accelerate all-electric new construction, but it is too soon to predict whether HCD will embrace this proposal.

Transportation Forecast and Additional Achievable Transportation Electrification (AATE) Forecasts

PG&E appreciates how the CEC has developed scenarios that demonstrate the impact of zero-emission vehicle policies, especially those stemming from the California Air Resources Board. PG&E expects these policies to be a major driving force for zero-emission vehicle adoption and believes it is critical to forecast the impacts of these policies on electricity demand.

PG&E also appreciates that the CEC is further considering the impacts of enroute charging, particularly direct current fast charging (DCFC) along rural corridors, as enroute charging can result in highly concentrated charging demand which coincides with peak travel times. To that end, PG&E notes that the CEC's current methodology of disaggregating total annual system energy across an average annual light-duty vehicle (LDV) or medium-duty and heavy-duty vehicle (MDHDV) load profile may not accurately account for localized and short duration peak charging conditions. PG&E would encourage the CEC to continue to enhance its LDV and MDHDV annual load profiles to more closely align with observed daily and seasonal variations in peak loading conditions. A charging capacity forecast based on

[3] Staff Workshop 2025 Energy Code Heat Pump Baselines, Solar Photovoltaic and Energy Storage Requirements
[4] CARB CALGreen package 11-3-23.pdf

<u>charger quantities and types as developed from statewide transportation electrification studies could also ensure adequate local demand is accounted for.</u>

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PG&E sincerely appreciates the CEC's ongoing commitment to transparency, collaboration, and public engagement and is grateful for the opportunity to comment on this IEPR workshop. Please reach out to me if you have any questions.

Sincerely,

Josh Harmon
State Agency Relations