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PACIFIC GAS AND ELECTRIC COMPANY

2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND RATE DESIGN

ERRATA TO OCTOBER 5, 2022 REBUTTAL TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2023 GAS TRANSMISSION AND STORAGE
COST ALLOCATION AND RATE DESIGN
REBUTTAL TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

REBUTTAL TESTIMONY OF KATIA SOKOLOFF ON

INTRODUCTION AND SCOPE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
REBUTTAL TESTIMONY OF KATIA SOKOLOFF ON
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
REBUTTAL TESTIMONY OF KATIA SOKOLOFF ON INTRODUCTION AND SCOPE

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Katia Sokoloff. This testimony responds to the direct testimony of The Utility Reform Network (TURN), and Small Business Utility Advocates (SBUA). Pacific Gas and Electric Company (PG&E) summarizes these parties' positions in Section B below. In Section D, my testimony also briefly identifies PG&E rebuttal to other intervenor proposals, which other PG&E witnesses are sponsoring.

B. Summary of TURN and SBUA Positions on Timing for Filing Future Applications

Q 2 Please provide a summary of parties' policies position to which you are responding?

A 2 This testimony responds to parties' testimony concerning one issue relating to Chapter 1 of prepared testimony: the timing to file the next Gas Transmission and Storage (GT&S) Cost Allocation and Rate Design (CARD) proceeding?

Q 3 What are parties' position regarding the timing of PG&E's next GT&S CARD proceeding?

A 3 Both TURN and SBUA recommend revisions to the timing for the next filing of the CARD application:

- TURN recommends a greater time lag between the filing of the General Rate Case (GRC) and the next CARD application. TURN states it is very challenging for intervenors to participate in both proceedings when they are running so close together. TURN recommends a six-month lag between the GRC and CARD filings.[1]

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[1] TURN Prepared Testimony, p. 3, lines 6-22.

- SBUA believes filing the CARD 90 days after the GRC application is filed is a reasonable goal; however, for practical consideration they recommend filing CARD later than 90 days from the filing of the GRC.[2]

Q 4 What is PG&E's response regarding any of parties recommendations?

A 4 PG&E agrees with recommendations made by parties, and responds further in Section C.

C. PG&E Agrees That Its Next CARD Application Filing Should Be Approximately Six Months After Its GRC I Application Filing

Q 5 Generally, what is the timing of the CARD applications?

A 5 Pursuant to Decision (D.) 19-09-025, p. 338, Ordering Paragraph (OP) 101, the California Public Utilities Commission (Commission) directed PG&E to file the next GT&S rate case consistent with the schedule required for test year. D.20-01-002, which modified the Commission's Rate Case Plan for Energy Utilities ordered a workshop, where PG&E presented a case schedule to mitigate stacking of proceedings. As part of that proposal, the CARD application was proposed to be the successor to the GT&S rate case and was filed within 90 days of filing PG&E's GRC I applications

Q 6 What is PG&E's proposal regarding the filing of future CARD applications?

A 6 PG&E proposed to file future CARD applications 90 days after a GRC Track 1 application was filed.[3]

Q 7 Which parties commented on the timing of filing the next CARD application.

A 7 TURN and SBUA were the only parties to address timing of future CARD applications.[4]

Q 8 What are parties' positions regarding PG&E's proposal for filing future CARD applications?

A 8 Both TURN and SBUA believe a greater time lag is needed between GRC and CARD. TURN argues that participating in both proceedings is very challenging for intervenors when they are running so close together.[5]

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2 SBUA Direct Testimony, p. 4.

3 PG&E Errata Testimony (Aug. 18, 2022), p. 1-9, lines 24-28.

4 TURN Prepared Testimony, p. 3, lines 6-22; SBUA Direct Testimony, p. 4.

5 TURN Prepared Testimony, p. 3, lines 13-14.

Q 9 Do parties have general criticisms and recommendations about PG&E's timing of filing the next CARD application.

A 9 Yes, TURN argues it is very challenging for intervenors to participate in both proceedings when they are running so close together.[6] TURN argues updates to the GRC result in many number changes in the CARD application.[7] It states that "[a] greater lag between the two applications would [allow for] up-to-date numbers in [the] CARD testimony."[8]

Similarly, SBUA states that while it agrees that filing "future CARD applications within 90 days is a reasonable goal", it recommends "a filing date of later than 90 days from the filing of GRC applications."[9]

Q 10 What is TURN's and SBUA recommendation?

A 10 TURN's recommendation is to have a 6-month lag between the next GRC and the next CARD application.[10] SBUA recommends a date greater than 90 days.[11]

Q 11 Do you agree with TURN's and SBUA's recommendations?

A 11 Yes, I agree. The timing of filing the current CARD application within 90 days of the GRC application has proved to be problematic. The 2023 GRC was the first time GT&S revenue requirements were decoupled from the CARD proceeding. PG&E was attempting to facilitate a simultaneous implementation with the new GT&S revenue requirements—as filed in the 2023 GRC application—to keep with the historical GT&S implementation of rates occurring with the implementation of the new GT&S revenue requirement.

Q 12 Do you agree with parties' recommendation?

A 12 Yes, PG&E agrees, finding reasonable the timing of filing the next CARD application to be around six months after the next GRC application is filed.

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6 TURN Prepared Testimony, p. 3, lines 13-14.

7 *Id.* at p. 3, lines 15-16.

8 *Id.* at p. 3, lines 20-22.

9 SBUA Direct Testimony, p. 4.

10 TURN Prepared Testimony, p. 3, lines 16-17.

11 SBUA Direct Testimony, p. 4.

D. Summary of PG&E Rebuttal Testimony Presented in Other Chapters

Q 13 Please provide a summary of PG&E Rebuttal Testimony.

A 13 PG&E presents rebuttal testimony to intervenor parties related to several proposals in CARD and the Core Gas Supply Portfolio. This exhibit is comprised of a substantive rebuttal to the following:

- Chapter 2A – Electric Generation Gas Demand and Throughput (Todd Peterson).
- Chapter 3 – Backbone Rate Inputs (Carl Orr).
- Chapter 4 – Local Transmission Allocation Study (Annette Taylor and James Chen).
- Chapter 5 – Electric Generation Local Transmission Rate Analytics (Todd Peterson).
- Chapter 6 – Cost Allocation and Rate Design (Patricia Gideon).
- Chapter 7 – Core Gas Supply (Pete Koszalka).

PG&E does not provide substantive rebuttal to the following, because they were not addressed in intervenor testimony. PG&E reserves the right to address the matters below if future developments warrant:

- Chapter 2B – Non-Generation Demand and Throughput Forecast (Andrew Klingler).
- Chapter 8 – G-NGV1 and G-NGV4 Tariff Modifications (Stephen Sheridan).

Q 14 Does PG&E additional rebuttal testimony in this Exhibit include new concerns and proposals that are raised by intervenor proposals?

A 14 Yes, PG&E presents Chapter 9, Gas Transmission and Storage Revenue Sharing Mechanism (RSM). This rebuttal testimony discusses PG&E's recommendations for revisions to the RSM, recommended *only in the event* the Commission adopts certain intervenor proposals to modify the Electric Generation (EG) rate design and/or increase PG&E's proposed EG load forecast/throughput. Proposals included in written testimony from three parties—The Utility Reform Network, the Northern California Generation Coalition, and Moss Landing Power Company LLC—if adopted, may affect collection of an adopted revenue requirement. The proposals involve several different issue areas. Therefore PG&E's rebuttal testimony responds to these recommendations in various chapters, with the issue of modification to the RSM discussed in Chapter 9, if the intervenor proposals were to be adopted.

E. Conclusion

Q 15 What is PG&E's recommendation for the timing of the fling of the next CARD?

A 15 For the reasons discussed above, PG&E recommends that future CARD application be filed around six months after a GRC application.

Q 16 Does PG&E have any other changes or corrections to Chapter 1?

A 16 No. PG&E does not have any other changes or corrections to its Chapter 1 proposals.

Q 17 Does this conclude your rebuttal testimony?

A 17 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2A

REBUTTAL TESTIMONY OF

TODD PETERSON ON

ELECTRIC GENERATION GAS DEMAND AND THROUGHPUT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2A
REBUTTAL TESTIMONY OF
TODD PETERSON ON
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2A
REBUTTAL TESTIMONY OF
TODD PETERSON ON
ELECTRIC GENERATION GAS DEMAND AND THROUGHPUT

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Todd Peterson, Principal Strategic Analyst. I am sponsoring Pacific Gas and Electric Company (PG&E) Prepared Testimony, Chapter 2A, Electric Generation Gas Demand and Throughput.[1] This testimony responds to the direct testimony of The Utility Reform Network (TURN)[2] and the Small Business Utility Advocates (SBUA).[3] PG&E summarizes the parties' positions in Section B below.

B. Summary of Parties Positions and PG&E's Responses

Q 2 Please briefly summarize the parties' positions with regard to Chapter 2A, Electric Generation Gas Demand and Throughput (EG forecast), and PG&E's response?

A 2 Two parties, TURN and SBUA, offer recommendations for the EG forecast for market-responsive generators. No party submitted written testimony disputing the non-market-responsive portion of the EG forecast. A summary of TURN's and SBUA's recommendations and PG&E's response follows:

- First, TURN proposed that PG&E's forecast of Market-Responsive Electric Generation (EG) gas demand be increased by 16.5 thousand dekatherms (MDth/d), to correct for an asserted downward bias in PG&E's results.[4]

  <u>PG&E's response:</u> PG&E disagrees and believes its EG forecast is reasonable and should be approved as proposed in its Prepared Testimony. Downward bias does not exist in the forecast, as the

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[1] I am also sponsoring Cost Allocation and Rate Design Chapters 5 and 9.

[2] TURN Prepared Testimony, Ch. 2A.

[3] SBUA Direct Testimony, Sections II.4 and II.5.

[4] TURN Prepared Testimony, p. 9, lines 11-14.

forecast relied on a PLEXOS model whose accuracy was confirmed by an appropriate backtest. TURN's proposal to use backtest results from 2019 (and 2020 that are averaged) are dated and creates results to the EG forecast that fails to account for the State of California's policy for the electric market in 2023-2026 timeframe.

- Second, TURN proposes to include EG forecast assumptions that incorporate other known constraints—including minimum generation constraints and electrical transmission connections outage rates.

  PG&E's response: PG&E disagrees and recommends rejection of this proposal. The backtest process ensures that the forecasting model produces reasonable approximations for actual throughput. The reasonable approximation in the 2019 and 2020 backtest years reflect that the forecasting model reproduces operational constraints found in the actual throughput.

- Third, TURN would have the EG forecast adjusted, with PG&E's "forecast of EG-LT [Electric Generation Local Transmission] gas demand upward by 91 MDth per day and reduce the Backbone-only gas demand downward by 32 MDth per day" if TURN's proposal for EG rate design is adopted in its Chapter 5 testimony.[5]

  PG&E's response: PG&E disagrees and opposes any revision to its EG forecast. TURN's proposal to adjust the EG forecast is based on a speculative assumption that its proposed EG-LT rate design will be adopted as it proposed. However, no reason exists to prepare forecasts on an assumption that any new rate design will be adopted. Moreover, PG&E's forecast uses a sound industry-endorsed PLEXOS production cost model for its forecast, which is superior to a "back-of-the-envelope" projection proposed by TURN.

- Fourth, SBUA notes that PG&E EG-LT forecasts a significant decrease in electric generation from natural gas from 2022 through 2026, then criticizes PG&E's forecast for predicting a more precipitous decline in electric generation from natural gas than is realistic.[6]

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5 *Id.* at p. 48, lines 1-3.

6 SBUA Direct Testimony, p. 5.

PG&E's response: SBUA's criticism is unsubstantiated, insufficient, and inaccurate, as PG&E's EG forecast assumptions uses recognized market conditions at the time of the forecast and incorporates the California Public Utilities Commission's (CPUC or Commission) adopted Integrated Resource Planning (IRP) Preferred System Plan (PSP).

- Fifth, SBUA says that PG&E did not comply with a Commission order to provide a 1-in-35 cold weather EG forecast.[7]

PG&E's response: SBUA's allegation is incorrect, as PG&E provided a cold weather EG forecast in compliance with Decision (D.) 19-09-025, Ordering Paragraph 86. The decision, however, only required the forecast to be provided and did not mandate its use within the case.

Q 3 Are there parties that do not dispute the EG forecast?

A 3 Yes, the written prepared testimony from Northern California Generation Coalition, Moss Landing, Indicated Shippers, Citadel Energy Marketing LLC, and Tourmaline Oil Marketing Corporation, and Calpine parties do not present a dispute to PG&E's EG forecast.

C. PG&E's Response to Parties' General Criticisms of Electric Generation Throughput and Demand Forecast

1. TURN's Request to Increase the EG Forecast to Adjust for an Alleged Downward Bias Should Be Rejected

Q 4 For background, what is the EG forecast? Please describe.

A 4 For purposes of the EG forecast in this case, PG&E's gas Local Transmission (LT) and backbone transmission system transports and delivers natural gas to on-system EG customers. PG&E designates electric generators into two groups based on the generator's responsiveness to electric market prices: non-market responsive and market responsive. The market-responsive EG group consists of gas-fired electric generators whose output varies in response to prices in the wholesale electricity and gas markets. The market-responsive group is further divided by the level of service provided by PG&E. LT customers on PG&E's transmission or distribution systems pay different transportation charges compared to those

7 *Id.* at pp. 6-7.

taking service off of the Backbone (BB) system. The EG forecast is more fully discussed in PG&E's prepared testimony.[8]

The market-responsive EG throughput forecast incorporates the CPUC's IRP 2021 PSP portfolio that increases greenhouse gas (GHG)-free electric generation and energy storage resources[9] "that meets a statewide 38 million metric ton (MMT) GHG target for the electric sector in 2030 and 35 MMT for 2032."[10]

PG&E presents a non-market-responsive EG forecast that was not addressed by any party in intervenor testimony.

Q 5 Summarize TURN's first criticism with the market-responsive EG forecast.

A 5 Yes, TURN claims that the EG forecast contains a downward bias of 16.5 MDth/d.[11] It states that a lack of minimum generation requirements from five Local Capacity Areas in PG&E's territory and failure to include assumptions for outage rates for key electrical transmission lines causes PG&E to underestimate the amount of gas generation that must come from plants served by PG&E's gas system. It states that these two omissions leads to a "slight downward bias," amounting to 16.5 MDth/d in a 2-year backtest analysis.[12] It recommends increasing the EG forecast by 16.5 MDth/d.[13]

Q 6 Does PG&E agree with TURN that the EG forecast contains a downward bias of 16.5 MDth/d?

A 6 No, PG&E objects to any request to revise the EG forecast. PG&E's EG forecast does not contain a downward bias. PG&E believes TURN's request to revise the EG forecast for this alleged downward bias in the

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8 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-1, lines 11-27.

9 D.22-02-004, Decision Adopting 2021 Preferred System Plan, Table 5, p. 101 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF.

10 *Id.* at p. 2. PG&E's initial forecast assumed the planned retirement of PG&E's Diablo Canyon Power Plant. California Governor Newsom recently signed Senate Bill 846, which seeks to continue operations at Diablo Canyon for an additional five years beyond 2025.

11 TURN Prepared Testimony, p. 5, lines 13-14.

12 *Id.* at p. 9, lines 4-10.

13 *Id.* at p. 9, lines 11-13.

backtest[14,15] should be rejected for three reasons: (1) no downward bias is evident in the analysis as the two backtest years show opposite results, one year down and one year up; (2) adjusting the EG forecast with backtest results carries forward the electric generation market conditions from 2019 and 2020 to the 2023-2026 forecast years; and (3) incorporating the backtest results lessens the impact of the CPUC's adopted IRP.

For context, PG&E's backtest shows how well its PLEXOS production cost model replicates previous electric generation conditions. Based on the backtest, the PLEXOS results are well-correlated to actual gas deliveries with no consistent bias. A backtest that is well-correlated serves as a validation of the forecast.

First, the backtest does not show a downward bias. The 2019 backtest shows an underestimate of 47 MDth/d compared to the actual throughput. The 2020 backtest shows an overestimate of 14 MDth/d.[16] These two years show no downward bias. 2019 is down and 2020 is up. These facts oppose TURN's analysis. TURN's proposal should be rejected.

Second, TURN's averaging of the backtest results and adjusting the EG forecast with these results carries forward the 2019 and 2020 electric generation market conditions to the 2023-2026 forecast years. As a reminder, the purpose of a backtest is to provide an indication of the accuracy of the modeling approach. TURN's use of the backtest results is a misuse of the backtest and its proposal should be rejected.

Third, relying on historical data by using the backtest would lessen the impact of the CPUC's adopted IRP, particularly GHG emissions. Adding the average backtest throughput results would project 2019 and 2020 electric generation conditions in the 2023-2026 EG forecast. The additional gas throughput TURN proposes would add GHG emissions. TURN's proposal should be rejected, as it will not reflect the impact of the CPUC IRP's impact to GHG emissions.

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14 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-7, line 12 to p. 2A-8, line 12.

15 The backtest shows the accuracy of the model compared to history.

16 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-9, Table 2A-3.

2. TURN's Claim that the EG Forecast Fails to Include Constraint Assumptions for Minimum Generation and Transmission Outages Is Incorrect

Q 7 Does TURN have an additional criticism about PG&E's EG forecast? Please describe.

A 7 Yes, TURN claims that the EG forecast does not include constraint assumptions for minimum generation for five Local Capacity Areas and for forced outage rates to transmission lines.[17] This is another reason TURN recommends adjusting the EG forecast upward by 16.5 MDth/day.

Q 8 Does PG&E agree with TURN that the EG forecast excludes the constraint assumptions for minimum generation and transmission outages?

A 8 No. The backtest presented in Chapter 2A illustrates how the PLEXOS model simulates history. The backtest process ensures that the model results are a reasonable approximation for actual throughput. Even though the California Independent System Operator (CAISO)[18] has identified local capacity constraints (i.e., local generation needs), it is reasonable to recognize that PG&E's backtest and model validation process captures these type of operation constraints. Figure 2A-1 and Table 2A-3 show how well the backtest simulates actual throughput. The correlation coefficient equals 0.89, very near 1.0 that signifies the level of association of historical throughput and how well PLEXOS simulates history.

For transmission outages, PG&E's transmission assumptions contain these constraints. These transmission assumptions for imports and exports into the CAISO are based on analysis conducted by the CAISO and CPUC as referenced in PG&E's Workpapers.[19]

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17 TURN Prepared Testimony, p. 5, line 17 to p. 9, line 14.

18 California ISO, 2022 Local Capacity Area Technical Study Final (Jan. 15, 2021), <http://www.caiso.com/InitiativeDocuments/2022LocalCapacityRequirementsFinalStudyManual.pdf> (as of Sept. 19, 2022).

19 PG&E Workpapers Supporting Chapter 2A, Confidential, p. 27:

> "During the peak period, CAISO imports are constrained to 6,000 MW to account for specified and unspecified imports, consistent with IRP planning assumptions. Outside the peak period, this constraint is relaxed to 10,805 MW using 2021 CAISO Step 6 analysis."

TURN's allegation that PG&E's EG forecast is missing Local Capacity Areas is also not correct. PG&E's EG forecast captures Local Capacity Areas, or in other words, minimum generation constraints. PG&E's EG forecast assumption on minimum generation is informed by the backtest and observing power plant historical throughput. It is incorrect to state that the PLEXOS modeling omitted consideration of these inputs. Adding the throughput impact from minimum generation and transmission would overstate the generation forecast.

3. TURN's Proposal to Increase EG-LT Gas Demand Forecast and Reduce the EG-BB Gas Demand Forecast, Based on an Potential Alternative EG-LT Rate Design, Should be Rejected

Q 9 What is TURN's next proposal regarding the EG-LT forecast?

A 9 TURN proposes to adjust PG&E's forecast of EG-LT gas demand upward by 91 MDth/d and reduce Backbone-only gas demand downward by 32 MDth/d.[20] This proposal is dependent on the Commission adopting its proposal for an alternative EG-LT rate design. The proposed rate design would include a combination of a fixed reservation charge and a volumetric charge, whereas the current rate design is a 100 percent volumetric charge. TURN explains its fixed charge proposal as part of its testimony PG&E's EG-LT rate design analysis in Chapter 5 of its prepared testimony?[21]

Q 10 Does PG&E agree with TURN's proposal to increase the EG-LT demand forecast and decrease the Backbone only forecast?

A 10 No. The proposal should be rejected for two reasons.

First, TURN's proposal is speculatively based on its proposed fixed charge, lower volumetric EG-LT rate design that may not be adopted as it proposed. The current rate design is an all-volumetric rate, and there is no indication that the Commission will revise this design. Even if the Commission were to consider a fixed and variable rate design at least three parties have presented alternative proposals so there is no current reason to expect TURN's proposal to be the frontrunner for adoption. Another option is for the Commission to adopt a variation of current rate proposals. The

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[20] TURN Prepared Testimony, p. 13, line 22.

[21] *Id.* at p. 9, line 15 to p. 13, line 31.

various outcomes make it difficult to revise a gas forecast solely on TURN's proposal. The impact on the EG forecast could be different than TURN's proposal or the Commission may adopt the current EG forecast.

Second, TURN's proposal uses an inferior "back-of-the-envelope" methodology. PG&E's forecast uses a sound industry-endorsed PLEXOS production cost model for its forecast.[22] For this proposal, TURN does not rely on the results of the PLEXOS model but instead relies on an un-modeled assumption. TURN states that PG&E's modeling presumed a 50 percent fixed charge. TURN states that, "absent actual model results, I approximated what the impact would be by applying the ratio of the fixed charge in the negotiated contracts (95%) to the actual fixed charged assumed by PG&E (50%)…,"[23] and then used this approximation for its LT and backbone adjustments. These approximations have not been tested. TURN's "back-of-the-envelope" method cannot capture additional impacts that the production cost model can. For example, PG&E's PLEXOS production cost model will be able to capture the interplay of competing electric generation sources, both with the PG&E service territory and throughout the Western Energy Coordination Council (WECC). TURN's method cannot do this.

In TURN's testimony on PG&E's Chapter 5 Electric Generation Local Transmission Rate Design Analytics, TURN says that production cost modeling, such as PG&E's PLEXOS model, "is by far the most recognized and utilized method for conducting forecasting of this nature, because it takes into account the impacts of a wide variety of variables on EG gas demand… ."[24] In contrast, TURN relies on an approximation to propose a revision to throughput that does not capture these variables. A change in gas transportation rates can have impacts outside of gas-fired electric generation gas demand on the PG&E LT system. For example, a change in gas transportation rates changes the dispatch order of competing generators. The dynamics will not be adequately captured by TURN's

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22 TURN recognizes that PLEXOS "is commonly used in the industry." TURN Prepared Testimony, p. 4, lines 18-19.

23 TURN Prepared Testimony, p. 13, lines 12-14.

24 *Id.* at p. 29, lines 21-23.

"back-of-the-envelope" arithmetic. The PLEXOS production cost model has the ability to calculate gas throughput impacts from changes in a gas-fired generators costs throughout the WECC.

4. SBUA's Claim That PG&E Is Forecasting a More Precipitous Decline in Electric Generation from Natural Gas than Is Realistic Is Incorrect

Q 11 What is SBUA's conclusion regarding PG&E's forecast for Electric Generation from natural gas?

A 11 SBUA appears to object to PG&E's forecast for electric generation, stating:

> …PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic. Natural gas derived electricity has proven to be reliable, cost effective, and reliably easy to construct and operate. This is especially true where there are no new plans for hydroelectric or Nuclear Powerplants. Solar Generation, with the backup of natural gas generation, is the direction in which California is headed.[25]

Q 12 Does PG&E agree with SBUA "that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."[26]?

A 12 No, PG&E does not agree with SBUA. PG&E presented an accurate electric generation forecast for the 2023-2026 cycle.

SBUA seems to admit that there will be a decline in in gas consumption in California, when it testified, "As more renewable resources are brought online, less natural gas generation will be necessary."[27] SBUA has not defined what constitutes a "precipitous" decline, thought it seems to agree that a forecasted decrease in consumption is reasonable.

SBUA further testified that it understood there is "overall declining natural gas usage in the state, and the intentional policy of reducing natural gas usage."[28]

Q 13 Please detail the reasons for the disagreement with SBUA's conclusion?

A 13 PG&E has five reasons for its disagreement. To the extent SBUA's comment suggests that PG&E's forecast is not accurate, PG&E disagrees.

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25 SBUA Direct Testimony, p. 5-6.

26 *Id.* at p. 5.

27 *Id.* at p. 6.

28 *Id.* at p. 7.

First, SBUA says that generation resources (or capacity) are being taken offline.[29] SBUA mentions the decommissioning of the Diablo Canyon Power Plant, hydroelectric power plants, and coal will eventually be completely phased out. PG&E's EG forecast includes the additional generation resources in the CPUC's 2019-2020 IRP PSP[30] for 2023-2026. The additional generation resources are multiple times larger than the Diablo Canyon Power Plant, any decommissioning of hydroelectric power plants and the phase out of coal. The PSP calls for the following additional installed nameplate capacity (megawatts (MW)) made up of mostly renewable generation and storage, relative to 2021:

- 13,202 in 2023;
- 20,161 in 2024;
- 26,511 in 2025; and
- 26,897 in 2026

Over these four years, this amounts to nearly 26,900 MW. As for coal generation, SBUA shows in its response to PG&E's data request one coal generation equals 303 gigawatt-hours (GWh) in 2021. This is only 35 average megawatts (aMW, the amount of generation over one year, divided by the number of hours in a year).[31] This generation or capacity is a very small amount compared to the PSP capacity listed above. With nearly 26,900 MW forecast to come online by mid-2026, this level of capacity will put downward pressure on gas-fired electric generation. PG&E's EG forecast reflects this new capacity and this helps explain why the forecast declines.

Second, PG&E's EG forecast is based on sound modeling methodology and assumptions. As described in PG&E's Workpapers,[32] PLEXOS is an industry recognized production cost model as used by the California Energy

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[29] SBUA's response to PG&E Data Request, Set One, dated 9/14/22, p. 5 in Attachment A, at the end of this chapter.

[30] D.22-02-004, Decision Adopting 2021 Preferred System Plan.

[31] 35 aMW = 303 GWh X 1,000 MWh/GWh ÷ 8,760 hours/year.

[32] PG&E Workpapers Supporting Chapter 2A, Confidential, p. 1.

Commission (CEC).[33] It is also used by others in the industry, such as CAISO, and globally as described by Energy Exemplar, the PLEXOS software vendor[34].

Third, the EG forecast assumptions uses comprehensive and well recognized assumptions that reflect the knowledge of market conditions at the time of the forecast. Beyond the PSP described above, PG&E's EG forecast uses the CEC's PLEXOS model as a base dataset. The CEC is the State's authority for electric production cost modeling.

Fourth, benchmarking PG&E's EG forecast to other forecasts, show similar trends. Two such sources are the 2022 Annual Energy Outlook[35] published by the Energy Information Administration and the CEC's[36] 2021 Integrated Energy Policy Report. Both of these forecasts show a downward trend over time.

Fifth, SBUA provides no information to support that PG&E's use of the PLEXOS model produces an inaccurate forecast, and fails to provide any alternative forecast that indicates a smaller decrease in throughput than forecasted by PG&E.

5. SBUA's Incorrectly Claims that PG&E Failed to Submit a Cold-Year Electric Generation Demand Forecast

Q 14 What is SBUA's testimony regarding a cold-year forecast?

A 14 SBUA states, "PG&E's application does not comply with Commission Decision 19-09-025, ordering paragraph 86. Decision 19-09-025 states that, "Pacific Gas and Electric Company shall provide a separate cold-year

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33 CEC, Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System (Mar. 2022), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=242233> (as of Sept. 19, 2022).

34 Energy Exemplar, PLEXOS, The Unified Energy Market Simulation Platform, <https://www.energyexemplar.com/plexos> (as of Sept. 19, 2022).

35 The Energy Information Administration (EIA) forecasts natural gas consumption for electric generation in the Pacific census region that shows a similar trend to the PG&E EG forecast. EIA, Annual Energy Outlook 2022, Table 61. Natural Gas Consumption by End-Use Sector and Census Division, Case: Reference case, https://www.eia.gov/outlooks/aeo/data/browser/.

36 Marshall, Lynn, Presentation – California Energy Demand 2021 Consumption and Sales Forecast Results (Dec. 16, 2021), p. 27, Statewide Managed Natural Gas Scenarios, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=240959&DocumentContentId=74810> (as of Sept. 19, 2022).

forecast of Electric Generation gas demand in its next Gas Storage and Transmission rate case application."[37]

Q 15 Does PG&E agree with SBUA that PG&E did not comply in providing a separate cold-year forecast of Electric Generation gas demand in its 2023 Gas Storage and Transmission Cost Allocation and Rate Design rate case application?

A 15 No. PG&E did comply in providing a separate cold year EG forecast. PG&E presented this forecast in is prepared testimony.[38] In fact, SBUA reproduced PG&E's cold-year forecast in its own testimony.[39] The forecast is developed for a 1-in-35 year cold year scenario.[40] Furthermore in SBUA's response to PG&E data request number one,[41] it states that PG&E developed a cold year forecast.

Q 16 What is SBUA's concern?

A 16 SBUA opines that the cold year forecast is too close to the baseline or average electric generation forecast. SBUA goes on to say that the baseline EG forecast for 2024 is 472 MDth/d and the cold year EG for 2024 is 474 MDth/d.

Q 17 Is SBUA correct in implying that a cold year forecast is not compliance with the Commission decision because there is only a slight difference between an average-weather and cold-year?

A 17 No, SBUA is not correct The Commission decision does not establish a minimum level of gap or increase that must exist between a cold-year and average weather forecast.

Q 18 What is PG&E's response to SBUA's comment regarding the cold-year forecast?

A 18 First, the annual average daily EG demand forecast measure does not show well the impact of cold temperature on EG demand. In PG&E's Chapter 2A

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37 SBUA Direct Testimony, p. 6-7.

38 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-12, line 22 to p. 2A-13, line 7 and Table 2A-5.

39 SBUA Direct Testimony, p. 7.

40 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-13, line 1.

41 SBUA's response to PG&E Data Request, Set One, dated 9/14/22, p. 6, Response a) "Table 2A-5 is a cold year electric generation demand forecast", in Attachment A at the end of this chapter.

testimony, Table 2A-1 Line 3 Market-Responsive 2024 Forecast is 472 MDth/d. In the same chapter, Table 2A-5, Line 3 Market-Responsive 2024 Forecast is 474 MDth/d. This is a spread of 2 MDth/d. Examining the forecasts at a monthly level,[42] EG gas throughput for December 2023 in the baseline forecast is 623 MDth/d. In the cold year forecast, the same EG gas demand is 637 MDth/d. This is a spread is 14 MDth/d. Looking at the forecast where cold temperatures impact the winter season shows more spread than an annual average 2 MDth/d compared to 14 MDth/d.

Second, the cold temperature forecast does not impact EG gas demand much during portions of the year. A cold year forecast does not impact summer months, marginally impacts shoulder months,[43] while having a higher impact during the winter. This causes the annual average view to appear lower than some may expect under cold temperature conditions.

Third, cold temperature conditions only slightly impact electric load for the gas-fired electric generation throughput. Cold weather mainly impacts space heating causing higher use of gas for heating, rather than electric use.

Fourth, growing renewable generation resources can fill in a portion of increased electric load from cold temperatures. This limits the need for gas-fired electric generation to serve electric load.

D. Conclusion

Q 19 What is PG&E's recommendation for EG forecast?

A 19 PG&E recommends the adoption of the EG forecast as presented in Chapter 2A.

As discussed in Section C, PG&E disagrees with TURN's and SBUA's criticism of the EG forecast. The EG forecast represents the best gas throughput electric generation forecast using the industry's preferred model PLEXOS. Additionally, the EG forecast uses the state of California's policy

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[42] See PG&E's response to Data Request TURN_002-Q002, dated 6/1/22, and TURN_002_Q002_Atch01.xlsx; and PG&E's response to Data Request TURN_003-Q004, dated 6/29/22, and TURN_003_Q004_Atch01.xlsx in Attachment B at the end of this chapter.

[43] Generally, shoulder months for this forecast includes April, May, September, and October.

regarding electric generation resources found in the CPUC's IRP PSP adopted by the Commission.

Q 20 Does this conclude your rebuttal testimony?

A 20 Yes it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2A

ATTACHMENT A

SBUA'S RESPONSE TO PG&E DATA REQUEST, SET ONE,

QUESTION 1(A) AT P. 5 (9/14/2022)

GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
(A.21-06-021)
SMALL BUSINESS UTILITY ADVOCATES
RESPONSE TO PG&E DATA REQUESTS, SET ONE

TO:	Chris McRoberts Email: chris.mcroberts@pge.com. Taylor Storer Email: T8SF@pge.com
FROM:	Michael Brown, on behalf of Small Business Utility Advocates Email: michael@mbrownlaw.net; Jennifer Weberski Email: jennifer@utilityadvocates.org Luke May Email: luke@utilityadvocates.org
DATE SENT:	August 28, 2022
DATE DUE:	September 14, 2022 (by agreement with PG&E)

DATA RESPONSES

Q 1: At page 5 of SBUA Testimony, SBUA testifies that it "believe(s) that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."

> **a) Please provide a detailed explanation of all reasons supporting SBUA's conclusion "that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."**
>
> **b) Please provide all calculations, data sources, assumptions, and documents that support SBUA's conclusion "that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."**

Response:

a) PG&E appears to forecast a steep decline in electric generation from natural gas (from recorded 2020 baseline levels) during the 2023-2026 period, as detailed below in Table 2A-1:

TABLE 2A-1
AVERAGE-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED
(MDTH/D)

Line No.		2020 Recorded	2023 Forecast	2024 Forecast[(a)]	2025 Forecast	2026 Forecast
1	Electric Generation					
2	Non-market-responsive EG	163	155	156	155	155
3	Market-responsive EG	654	319	316	342	371
4	*Local Transmission*	*287*	*60*	*58*	*59*	*60*
5	*Backbone-only*	*367*	*259*	*258*	*284*	*312*
6	Total Electric Generation	817	474	472	497	527

(a) Since 2024 is a leap year, calculating an annual average value from monthly data results in throughput that is slightly higher than in other years.

2020 Total Electricity System Power

Contact

Michael Nyberg
Energy Assessments Division
916-931-9477

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Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	Total Imports (GWh)	Percent of Imports	Total California Energy Mix (GWh)	Total Califor Power Mix
Coal	317	0.17%	194	6,963	7,157	8.76%	7,474	2.74%
Natural Gas	92,298	48.35%	70	8,654	8,724	10.68%	101,022	37.06%
Oil	30	0.02%	-	-	0	0.00%	30	0.01%
Other (Waste Heat / Petroleum Coke)	384	0.20%	125	9	134	0.16%	518	0.19%
Nuclear	16,280	8.53%	672	8,481	9,154	11.21%	25,434	9.33%
Large Hydro	17,938	9.40%	14,078	1,259	15,337	18.78%	33,275	12.21%
Unspecified	-	0.00%	12,870	1,745	14,615	17.90%	14,615	5.36%
Total Non-Renewables and Unspecified Energy	127,248	66.65%	28,009	27,111	55,120	67.50%	182,368	66.91%
Biomass	5,680	2.97%	975	25	1,000	1.22%	6,679	2.45%
Geothermal	11,345	5.94%	166	1,825	1,991	2.44%	13,336	4.89%
Small Hydro	3,476	1.82%	320	2	322	0.39%	3,798	1.39%
Solar	29,456	15.43%	284	6,312	6,596	8.08%	36,052	13.23%
Wind	13,708	7.18%	11,438	5,197	16,635	20.37%	30,343	11.13%
Total Renewables	63,665	33.35%	13,184	13,359	26,543	32.50%	90,208	33.09%
Total System Energy	190,913	100.00%	41,193	40,471	81,663	100.00%	272,576	100.00

2021 Total System Electric Generation

Contact

Michael Nyberg
Energy Assessments Division

2020 Total System Electric Generation and previous years

Depending on browser width, scrolling of table may be necessary. Scroll bar is at bottom of table.

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	Total Imports (GWh)	Percent of Imports	Total California Energy Mix (GWh)	Total California Power Mix
Coal	303	0.2%	181	7,788	7,969	9.5%	8,272	3.0%
Natural Gas	97,431	50.2%	45	7,880	7,925	9.5%	105,356	37.9%
Oil	37	0.0%	-	-	-	0.0%	37	0.0%
Other (Waste Heat/Petroleum Coke)	382	0.2%	68	15	83	0.1%	465	0.2%
Nuclear	16,477	8.5%	524	8,756	9,281	11.1%	25,758	9.3%
Large Hydro	12,036	6.2%	12,042	1,578	13,620	16.3%	25,656	9.2%
Unspecified	-	0.0%	8,156	10,731	18,887	22.6%	18,887	6.8%
Total Thermal and Non-Renewables	**126,666**	**65.2%**	**21,017**	**36,748**	**57,764**	**69.1%**	**184,431**	**66.4%**
Biomass	5,381	2.8%	864	26	890	1.1%	6,271	2.3%
Geothermal	11,116	5.7%	192	1,906	2,098	2.5%	13,214	4.8%
Small Hydro	2,531	1.3%	304	1	304	0.4%	2,835	1.0%
Solar	33,260	17.1%	220	5,979	6,199	7.4%	39,458	14.2%
Wind	15,173	7.8%	9,976	6,405	16,381	19.6%	31,555	11.4%
Total Renewables	**67,461**	**34.8%**	**11,555**	**14,317**	**25,872**	**30.9%**	**93,333**	**33.6%**
Total System Energy	**194,127**	**100.0%**	**32,572**	**51,064**	**83,636**	**100.0%**	**277,764**	**100.0%**

As shown by the charts above,[1] natural gas and solar generation increased from 2020 to 2021, on a percent basis, as reported by the CEC. Expert Michael Brown contends that this trend is likely to accelerate (or remain stable) in the coming years; in particular, solar generation will increase – due to favorable economics, and legislative mandates. Natural gas is a stable source of electricity, which can "back up" solar generation during periods of intermittency. This combination seems to be acceptable in California, and therefore is likely to be used to replace other types of generation.[2]

[1] *Available at*: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation; https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation/2020

[2] See *e.g.*: https://www.npr.org/2022/05/07/1097376890/for-a-brief-moment-calif-fully-powered-itself-with-renewable-energy

Also, other types of generation are being taken offline. This is primarily because: (1) California has decided to decommission Diablo Canyon and SONGS; (2) hydroelectric projects – writ large – are not being expanded, but rather are being decommissioned or made secondary to environmental interests; and (3) coal will eventually be completely phased out in California. Thus, because nuclear and hydro facilities are being decommissioned and because stable "baseload" will be necessary to complement solar generation, we believe that reducing gas usage for electric generation from 817 Million Dekatherms per day (2020) to 472-474 Million Dekatherms per day (2023 & 2024 forecast) presents risks for small business ratepayers.

b) Please see response to (a) above. Mr. Brown did not perform any additional independent calculations.

Q 2: At page 6 of SBUA Testimony, SBUA testifies that "PG&E's application does not comply with Commission Decision 19-09-025, ordering paragraph 86."

a) Please confirm that PG&E provided a cold year electric generation demand forecast in its Prepared Testimony, at Chapter 2, Section D and Table 2A-6.

b) Does SBUA contend that the forecast presented in its Prepared Testimony (at Chapter 2, Section D and Table 2A-6) does not comply with Decision 19-09-025, OP 86?

c) If so, please provide a detailed explanation of the reasons that SBUA's concludes that the PG&E's Prepared Testimony does not comply with the Decision.

d) Please provide SBUA's all calculations, data sources, assumptions, and documents that supports SBUA's conclusion that PG&E did not comply with decision (D) 19-09-025, Ordering Paragraph (OP) 86 to include a forecast of electric generation gas demand using a 1-in-35 cold year scenario.

Response:

a) Table 2A-5 is a cold year electric generation demand forecast. The testimony refers to Table 2A-5, not Table 2A-6. After review of PG&E's testimony, there does not appear to be a "Table 2A-6." For the purposes of this response, SBUA assumes that "2A-6" was a typo.

b) Decision 19-09-025 states that, "Pacific Gas and Electric Company shall provide a separate cold-year forecast of Electric Generation gas demand in its next Gas Storage and Transmission rate case application." While Expert Brown acknowledges that PG&E did provide a cold year electric generation demand forecast, Expert Brown does not believe that Table 2A-5 fulfilled the Commission's intent of the ordering paragraph. The forecast did not serve the purpose of the Commission Order, which was to model an extreme cold weather event. That exercise would help determine the capacity of the natural gas delivery system.

c) As discussed above, while PG&E did provide a forecast, Expert Brown's opinion is that PG&E did not comply with the intent of the Commission's request. PG&E should have used a different methodology in making its cold weather forecast. As noted in SBUA's testimony, we recommend that PG&E use a methodology similar to SEMPRA's 15-year cold year electric generation demand forecast.

Q 3: At page 14 of SBUA Testimony, SBUA testifies, "However, a manipulation (and thereby subsidization) of these generators through gas rates is inappropriate."

> **a) Does a rate design that incorporates recovery of fixed cost of service in a fixed charge provide a discount?**
>
> **b) Does SBUA agree that PG&E's local transmission function costs are fixed in nature?**
>
> **c) Does SBUA agree that PG&E's alternative negotiated fixed charge EGLT rate design-based contracts (PG&E Prepared Testimony, Chapter 5) did not provide a discount to the power plants that chose that option?**
>
> **d) If SBUA asserts that PG&E's alternative negotiated fixed charge EGLT rate design provides a discount to power plants that chose that option, then explain in detail the discount that these power plants received. Quantify the amount or level of discount these power plants received.**

Response:

a) As asked, it is difficult to say whether a rate design that incorporates a fixed cost of service in a fixed charge provides a discount, without further cost of service information or the charge; rate designs that incorporate both a fixed and variable charge may provide either a discount or overcharge, relative to the cost of service. As such the G-EG LT tariff should attempt to recover the exact cost of providing service to customers using that tariff whether it be by fixed or variable charges.

b) Local transmission function costs are fixed in nature with some variability in terms of maintenance costs.

c) – (d). Expert Brown's understanding (based on PG&E's testimony) is that the G-EG LT tariff only recovered 90 percent of the annual revenue requirement. From that information, he deduced that (in general) customers choosing that option would receive a discount. Mr. Brown did not conduct an independent study.

Q 4: At page 17 of SBUA Testimony, SBUA testifies, "PG&E states that wholesale customers exhibit more uniform demand patterns, thereby not necessitating storage." SBUA's footnote refers to See PG&E's Prepared Testimony at page 6-19.

> **a) Please confirm that the PG&E testimony referred to by SBUA does not refer to or identify wholesale customers, but states, "Off-system customers of PG&E backbone transmission system currently pay for this service in their unbundled backbone rates despite not being end-use customers and not contributing to the imbalances across the hours of the day or days of the month." PG&E Prepared Testimony, p. 6-18, lines 1-4 (August 18, 2022).**
>
> **b) Confirm that "wholesale customers" are not the same as "off-system" customers.**
>
> **c) Please confirm that, with regard to wholesale customers, PG&E testified that "Wholesale customers serve almost solely end-use customers classified as core. Therefore, PG&E proposes that wholesale customers pay the Inventory Management rate associated with PG&E's total Core group." PG&E Prepared Testimony, p. 6-22, lines 4-7 (August 18, 2022).**

Response:

a. SBUA's testimony refers to page 6-19, lines 3-8, which states: "Core NGV and Large Commercial classes closely mimic the Industrial Distribution class in terms of winter usage …" Expert Brown interprets this statement as meaning that natural gas usage amongst these classes of customers is relatively uniform, and these classes are, therefore, in less need of natural gas storage. The testimony was not referring to wholesale customers / large customers in general, such as large commercial and large industrial customers. SBUA's testimony was not intending to refer to off-system customers, and was not trying to imply that PG&E was referring to off-system customers.

b. Correct - wholesale customers are not the same as off-system customers.

c. SBUA agrees that this is in PG&E's testimony. However, SBUA's testimony was in reference to 6-20; lines 18-21.

Q 5: At page 17 of SBUA Testimony regarding PG&E's proposal to change the recovery of the Inventory Management service, SBUA testifies, "However, PG&E fails to acknowledge the above factors, and likewise does not explain why such a large aggregate change is necessary."

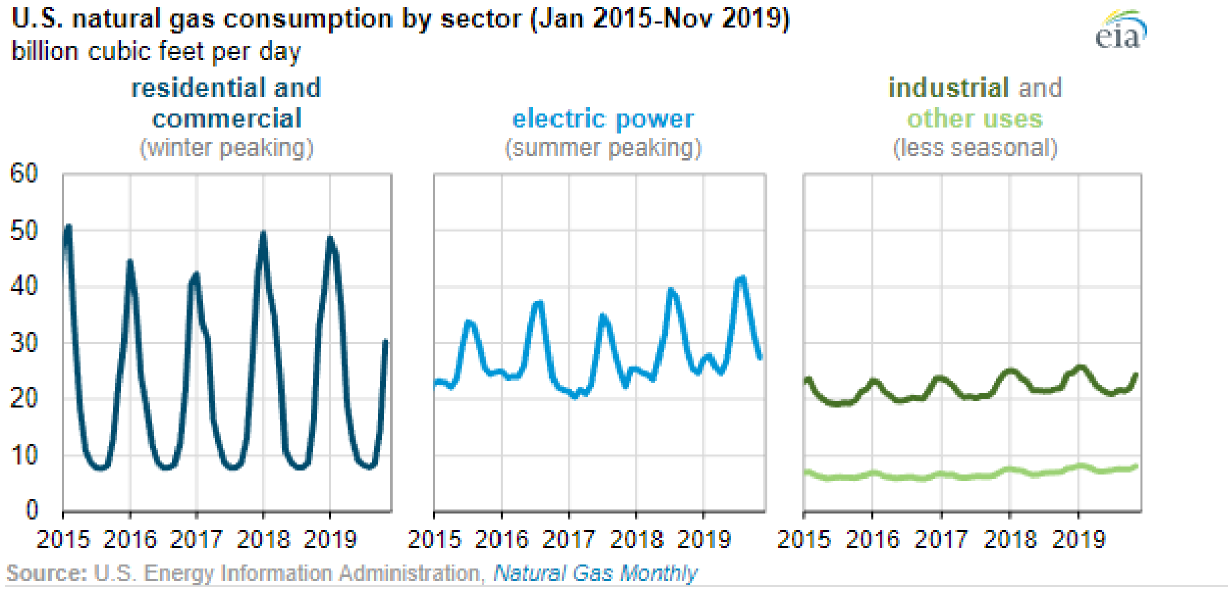
> **a) Please confirm that PG&E's testimony (PG&E, Errata II, August 18, 2022 Clean, at p. 6-15 to 6-17) provides the rationale for a more cost-based recovery of the Inventory Management cost?**
>
> **b) Specifically, does SBUA believe that the increase over time in the Inventory Management's revenue requirement and the Gas Planning OIR's discussion of increased volatility of EG demand for natural gas as discussed (both referenced in PG&E's testimony (p. 6-15 and 6-16, August 18, 2022 Errata II Clean) is not an explanation as to why an examination of the class-based causation of inventory management services is warranted?**
>
> **c) Does SBUA acknowledge that large commercial/industrial customers have load profiles that are far more consistent across both summer and winter seasons than profiles of residential/small commercial on one hand and electric generation on the other?**

Response:

a) Expert Brown has reviewed PG&E's Errata and confirms that PG&E provided a rationale. The Errata explains why recovery by customer class of increased use of the storage system was warranted on a cost causation basis.

b) PG&E makes reference to the implementation of the Natural Gas Storage Strategy (NGSS) and the 2019 GT&S Rate Case as the reason why Inventory Management Service was established. PG&E now proposes to recover costs based on customer class. Since PG&E does own natural gas storage facilities, the analysis and cost allocation are currently in dispute and up for discussion. PG&E must purchase and maintain cushion gas, as well as maintain its various gas storage and transmission assets. However, it is unclear why small commercial customers and residential customers need to be allocated a large portion of "Inventory Management" costs. PG&E uses daily gas fluctuations as a reason for a large Inventory Management discrepancy amongst customer classes. However, it is unclear what cost these variations are actually causing. PG&E has a fixed asset (natural gas storage) which requires cushion gas and maintenance. So, it is unclear why small commercial customers, as a class, are causing PG&E to incur Inventory Management costs.

   Expert Brown further believes that if PG&E intends to increase its usage of, and rely more heavily upon natural gas storage (as opposed to firm natural gas delivery contracts), then it must consider that small businesses are a smaller user of electricity in the summer time and greater user of natural gas in the winter time.[3]



As far as storage, most electric generators are more interested in securing storage capacity (and using natural gas) during the summer time, when they must generate electricity during the periods of highest demand. If PG&E is going to differentiate between classes, and allocate costs based on class-based causation of inventory management, then small commercial customers should receive a lesser cost allocation.

c) Expert Brown agrees that large commercial/industrial customers generally have more consistent load profiles (both summer and winter seasons) than residential and small commercial customers.

[3] See *e.g.* https://www.eia.gov/todayinenergy/detail.php?id=42815

Q 6: At page 17 of SBUA Testimony, SBUA testifies, "Furthermore, natural gas storage is cheaper in the winter months."

> **a) Please provide all workpapers, studies, analyses, or other documents that support SBUA's conclusion that natural gas storage is cheaper in the winter months.**
>
> **b) Please provide all workpapers, studies, analyses, or other documents that SBUA's conclusion natural gas storage withdrawals in the summer are complementary to winter withdrawal.**

Response subparts a & b:

> Expert Brown acknowledges that it is possible that this statement may not be true. However, Expert Brown has prior experience in managing natural gas inventory at natural gas power plants; this experience has demonstrated that, generally, companies purchase gas storage capacity year-round. Like a balloon, they fill up natural gas storage capacity during the winter-time, with any excess gas. Then as summer approaches, they use excess natural gas to run the power plant, in addition to using whatever firm natural gas deliveries are supplied to them. The exact costs of natural gas storage, by season, would vary by demand in the market.

Q 7: At page 17 of SBUA Testimony, SBUA testifies, "the two should compliment each other" when discussing residential vs EG demands for inventory management service.

a) **Does SBUA testimony acknowledge that residential/small commercial usage on the one hand and electric generation on the other hand both have load shapes impacted by variations in temperatures?**

b) **Does PG&E propose roughly similar Inventory Management rate components for the residential/small Commercial/wholesale and electric generation customer classes? (Table 6-12, page 6-23, August 18 filing)?**

c) **Are these PG&E proposed Inventory Management rate components both significantly higher than those proposed for large commercial and industrial customer classes?**

Responses subparts a-c:

a. Yes.

b. Yes. PG&E does propose roughly similar Inventory Management rate components for residential & small commercial/ Wholesale/ and Electric Generation Customer classes in line 3 "Implementation Rates under this proposal 2023".

c. Please clarify the question and provide the actual cost of inventory management for all customer classes, in order for SBUA to provide an informed response about what the cost of service for each customer class should be.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2A

ATTACHMENT B

PG&E'S RESPONSE TO TURN SET TWO, QUESTION 2

(6/1/2022)

PACIFIC GAS AND ELECTRIC COMPANY
GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	TURN_002-Q002		
PG&E File Name:	GTS-CARD-2023_DR_TURN_002-Q002		
Request Date:	May 16, 2022	Requester DR No.:	002
Date Sent:	June 1, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Todd Peterson	Requester:	Camille Stough

QUESTION 002

Please provide the forecast of *daily* market-responsive EG gas demand for the entire forecast period from PG&E's PLEXOS EG gas demand forecast modeling.

ANSWER 002

Please refer to attachment, "GTS-CARD-2023_DR_TURN_002-Q002Atch01.xlsx" for PG&E's forecast of daily market-responsive EG gas demand for the entire forecast period (June 2021 through December 2026).

The daily forecast begins on row 84. Market-responsive, LT data can be found in column E and market-responsive, BB data can be found in column F.

In order to facilitate review, PG&E has provided non-market-responsive data in column G and total EG data in column H such that the data aligns with what was presented in Table 2A-1 of PG&E's Revised Testimony, filed May 10, 2022. Monthly data is provided in rows 14 through 80 and annual data is provided in rows 6-10.

Please note that since PG&E's methodology for non-market-responsive EG relies on monthly-level data, the values provided in the daily cells for this column are simply the monthly average repeated for each day of a given month.

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day		Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
Annual Forecast							
2021	<>0	<>0		n/a	n/a	n/a	n/a
2022	<>0	<>0		162	239	155	556
2023	<>0	<>0		59	235	155	450
2024	<>0	<>0		56	231	156	443
2025	<>0	<>0		54	246	155	455
2026	<>0	<>0		55	278	155	488

Note - since 2023 GT&S CARD forecast starts in June 2021, annual values for this year are not calculated

Year	Month	Day	Days/Mo	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
Monthly Forecast							
2021	6	<>0	30	155	159	159	474
2021	7	<>0	31	374	463	164	1,001
2021	8	<>0	31	309	427	188	924
2021	9	<>0	30	355	483	186	1,024
2021	10	<>0	31	239	261	174	674
2021	11	<>0	30	208	291	142	641
2021	12	<>0	31	279	426	149	855
2022	1	<>0	31	198	367	140	706
2022	2	<>0	28	168	281	164	614
2022	3	<>0	31	110	99	131	339
2022	4	<>0	30	73	60	129	262
2022	5	<>0	31	51	57	138	246
2022	6	<>0	30	54	118	159	332
2022	7	<>0	31	187	271	164	622
2022	8	<>0	31	213	348	188	749
2022	9	<>0	30	257	334	186	777
2022	10	<>0	31	197	230	174	600
2022	11	<>0	30	193	311	142	646
2022	12	<>0	31	238	395	149	783
2023	1	<>0	31	75	355	140	571
2023	2	<>0	28	71	265	164	500
2023	3	<>0	31	47	105	131	282
2023	4	<>0	30	41	65	129	235
2023	5	<>0	31	37	60	138	235
2023	6	<>0	30	38	126	159	324
2023	7	<>0	31	56	276	164	496
2023	8	<>0	31	62	351	188	600
2023	9	<>0	30	69	276	186	531
2023	10	<>0	31	64	269	174	507

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day		Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	11	<>0	30	72	273	142	487
2023	12	<>0	31	82	398	149	630
2024	1	<>0	31	65	337	140	542
2024	2	<>0	29	59	207	164	430
2024	3	<>0	31	45	103	131	278
2024	4	<>0	30	42	64	129	235
2024	5	<>0	31	37	58	138	233
2024	6	<>0	30	37	123	159	320
2024	7	<>0	31	51	255	164	469
2024	8	<>0	31	55	323	188	566
2024	9	<>0	30	70	279	186	535
2024	10	<>0	31	55	240	174	469
2024	11	<>0	30	70	314	142	526
2024	12	<>0	31	87	455	149	692
2025	1	<>0	31	60	348	140	548
2025	2	<>0	28	56	226	164	447
2025	3	<>0	31	44	103	131	278
2025	4	<>0	30	38	64	129	232
2025	5	<>0	31	36	59	138	232
2025	6	<>0	30	37	124	159	320
2025	7	<>0	31	47	246	164	457
2025	8	<>0	31	49	308	188	545
2025	9	<>0	30	64	289	186	538
2025	10	<>0	31	54	271	174	499
2025	11	<>0	30	66	405	142	614
2025	12	<>0	31	93	499	149	741
2026	1	<>0	31	67	414	140	621
2026	2	<>0	28	61	316	164	541
2026	3	<>0	31	45	126	131	301
2026	4	<>0	30	40	64	129	234
2026	5	<>0	31	35	60	138	234
2026	6	<>0	30	37	126	159	322
2026	7	<>0	31	50	273	164	487
2026	8	<>0	31	53	329	188	570
2026	9	<>0	30	65	348	186	599
2026	10	<>0	31	52	328	174	553
2026	11	<>0	30	65	430	142	637
2026	12	<>0	31	87	516	149	752

Year	Month	Day		Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
Daily Forecast						
2021	6	1	87	57	159	303
2021	6	2	79	72	159	311
2021	6	3	96	86	159	341
2021	6	4	180	115	159	454
2021	6	5	137	113	159	409
2021	6	6	65	60	159	285
2021	6	7	80	88	159	327
2021	6	8	181	176	159	517
2021	6	9	138	214	159	512
2021	6	10	93	76	159	328
2021	6	11	92	72	159	323
2021	6	12	72	108	159	339
2021	6	13	36	54	159	249
2021	6	14	161	154	159	474
2021	6	15	332	323	159	815
2021	6	16	129	79	159	367
2021	6	17	206	162	159	527
2021	6	18	288	269	159	716
2021	6	19	130	106	159	395
2021	6	20	65	65	159	289
2021	6	21	136	149	159	444
2021	6	22	190	135	159	485
2021	6	23	202	307	159	668
2021	6	24	350	536	159	1,045
2021	6	25	318	360	159	837
2021	6	26	150	143	159	452
2021	6	27	83	37	159	279
2021	6	28	153	153	159	465
2021	6	29	247	266	159	673
2021	6	30	181	250	159	590
2021	7	1	234	338	164	736
2021	7	2	401	473	164	1,037
2021	7	3	372	483	164	1,019
2021	7	4	240	391	164	795
2021	7	5	439	416	164	1,018
2021	7	6	567	619	164	1,349
2021	7	7	449	649	164	1,262
2021	7	8	358	454	164	976
2021	7	9	238	316	164	717
2021	7	10	227	265	164	656
2021	7	11	169	393	164	726

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2021	7	12	266	412	164	841
2021	7	13	307	307	164	778
2021	7	14	414	436	164	1,014
2021	7	15	521	563	164	1,248
2021	7	16	516	555	164	1,235
2021	7	17	370	464	164	997
2021	7	18	188	320	164	671
2021	7	19	233	308	164	704
2021	7	20	304	317	164	784
2021	7	21	376	378	164	917
2021	7	22	505	601	164	1,270
2021	7	23	479	684	164	1,327
2021	7	24	372	399	164	935
2021	7	25	301	444	164	909
2021	7	26	441	536	164	1,141
2021	7	27	454	593	164	1,210
2021	7	28	562	681	164	1,407
2021	7	29	518	585	164	1,266
2021	7	30	507	561	164	1,232
2021	7	31	263	423	164	849
2021	8	1	127	308	188	622
2021	8	2	261	483	188	931
2021	8	3	338	511	188	1,036
2021	8	4	377	556	188	1,121
2021	8	5	251	335	188	773
2021	8	6	254	346	188	788
2021	8	7	190	249	188	627
2021	8	8	100	185	188	473
2021	8	9	159	246	188	593
2021	8	10	263	415	188	866
2021	8	11	327	468	188	983
2021	8	12	249	390	188	827
2021	8	13	390	507	188	1,085
2021	8	14	224	297	188	709
2021	8	15	196	338	188	722
2021	8	16	580	650	188	1,417
2021	8	17	456	552	188	1,196
2021	8	18	343	444	188	974
2021	8	19	390	403	188	980
2021	8	20	329	373	188	890
2021	8	21	159	312	188	658
2021	8	22	203	346	188	737

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2021	8	23	441	449	188	1,078
2021	8	24	453	531	188	1,172
2021	8	25	394	584	188	1,167
2021	8	26	459	572	188	1,219
2021	8	27	480	594	188	1,262
2021	8	28	260	384	188	832
2021	8	29	123	278	188	589
2021	8	30	339	518	188	1,045
2021	8	31	466	620	188	1,274
2021	9	1	535	622	186	1,344
2021	9	2	490	592	186	1,269
2021	9	3	428	619	186	1,234
2021	9	4	282	421	186	889
2021	9	5	183	302	186	671
2021	9	6	317	436	186	939
2021	9	7	478	640	186	1,305
2021	9	8	370	528	186	1,084
2021	9	9	390	563	186	1,138
2021	9	10	451	640	186	1,276
2021	9	11	250	381	186	817
2021	9	12	245	490	186	921
2021	9	13	431	606	186	1,223
2021	9	14	532	628	186	1,347
2021	9	15	427	503	186	1,116
2021	9	16	340	480	186	1,006
2021	9	17	225	356	186	767
2021	9	18	156	255	186	597
2021	9	19	154	206	186	546
2021	9	20	418	551	186	1,155
2021	9	21	446	492	186	1,124
2021	9	22	448	413	186	1,047
2021	9	23	396	481	186	1,063
2021	9	24	383	444	186	1,013
2021	9	25	328	433	186	948
2021	9	26	158	305	186	649
2021	9	27	302	506	186	995
2021	9	28	304	500	186	991
2021	9	29	381	517	186	1,084
2021	9	30	398	565	186	1,148
2021	10	1	225	372	174	771
2021	10	2	251	193	174	618
2021	10	3	280	219	174	673

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2021	10	4	308	438	174	919
2021	10	5	294	303	174	771
2021	10	6	275	299	174	748
2021	10	7	258	247	174	680
2021	10	8	226	257	174	657
2021	10	9	188	183	174	545
2021	10	10	199	202	174	576
2021	10	11	285	314	174	772
2021	10	12	323	401	174	898
2021	10	13	325	350	174	848
2021	10	14	300	280	174	753
2021	10	15	261	277	174	712
2021	10	16	72	138	174	384
2021	10	17	111	151	174	436
2021	10	18	299	278	174	750
2021	10	19	295	276	174	745
2021	10	20	309	246	174	729
2021	10	21	275	241	174	691
2021	10	22	210	253	174	636
2021	10	23	195	260	174	629
2021	10	24	197	262	174	633
2021	10	25	265	254	174	693
2021	10	26	192	227	174	593
2021	10	27	144	226	174	544
2021	10	28	209	271	174	654
2021	10	29	279	242	174	694
2021	10	30	183	231	174	588
2021	10	31	176	215	174	564
2021	11	1	171	214	142	528
2021	11	2	193	234	142	569
2021	11	3	264	317	142	722
2021	11	4	190	345	142	677
2021	11	5	223	389	142	755
2021	11	6	153	249	142	544
2021	11	7	138	246	142	526
2021	11	8	265	353	142	759
2021	11	9	225	409	142	776
2021	11	10	227	422	142	791
2021	11	11	202	448	142	793
2021	11	12	182	401	142	725
2021	11	13	77	73	142	292
2021	11	14	74	92	142	308

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2021	11	15	210	191	142	543
2021	11	16	237	380	142	759
2021	11	17	222	489	142	854
2021	11	18	266	369	142	776
2021	11	19	241	360	142	743
2021	11	20	168	150	142	460
2021	11	21	169	212	142	523
2021	11	22	269	407	142	818
2021	11	23	270	321	142	734
2021	11	24	285	253	142	680
2021	11	25	184	199	142	526
2021	11	26	200	212	142	554
2021	11	27	168	159	142	468
2021	11	28	151	180	142	473
2021	11	29	274	293	142	709
2021	11	30	334	379	142	854
2021	12	1	281	500	149	931
2021	12	2	267	536	149	953
2021	12	3	280	489	149	919
2021	12	4	202	235	149	586
2021	12	5	119	154	149	422
2021	12	6	285	297	149	731
2021	12	7	260	421	149	830
2021	12	8	312	488	149	949
2021	12	9	364	545	149	1,059
2021	12	10	321	506	149	977
2021	12	11	146	237	149	533
2021	12	12	152	382	149	683
2021	12	13	287	461	149	898
2021	12	14	449	537	149	1,136
2021	12	15	451	548	149	1,149
2021	12	16	360	570	149	1,079
2021	12	17	275	525	149	949
2021	12	18	213	410	149	773
2021	12	19	254	387	149	790
2021	12	20	343	392	149	884
2021	12	21	337	459	149	945
2021	12	22	247	464	149	861
2021	12	23	339	427	149	915
2021	12	24	303	385	149	837
2021	12	25	317	406	149	872
2021	12	26	300	433	149	882

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2021	12	27	316	431	149	897
2021	12	28	166	362	149	677
2021	12	29	245	453	149	848
2021	12	30	271	496	149	917
2021	12	31	199	268	149	617
2022	1	1	176	449	140	766
2022	1	2	207	462	140	810
2022	1	3	239	487	140	866
2022	1	4	231	382	140	754
2022	1	5	240	263	140	643
2022	1	6	114	163	140	417
2022	1	7	168	172	140	480
2022	1	8	182	248	140	570
2022	1	9	162	362	140	664
2022	1	10	188	444	140	772
2022	1	11	213	453	140	807
2022	1	12	224	418	140	782
2022	1	13	237	457	140	834
2022	1	14	245	299	140	684
2022	1	15	137	184	140	461
2022	1	16	183	400	140	724
2022	1	17	184	445	140	770
2022	1	18	172	387	140	699
2022	1	19	295	440	140	876
2022	1	20	214	501	140	856
2022	1	21	194	375	140	710
2022	1	22	196	339	140	675
2022	1	23	171	373	140	685
2022	1	24	222	507	140	869
2022	1	25	240	485	140	865
2022	1	26	256	498	140	894
2022	1	27	216	505	140	861
2022	1	28	173	317	140	631
2022	1	29	142	80	140	362
2022	1	30	141	130	140	411
2022	1	31	174	361	140	676
2022	2	1	122	267	164	553
2022	2	2	113	208	164	485
2022	2	3	115	210	164	488
2022	2	4	92	119	164	375
2022	2	5	90	107	164	360
2022	2	6	115	147	164	426

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	2	7	194	346	164	704
2022	2	8	167	383	164	713
2022	2	9	213	422	164	799
2022	2	10	227	473	164	864
2022	2	11	171	450	164	785
2022	2	12	193	336	164	693
2022	2	13	191	361	164	716
2022	2	14	209	497	164	871
2022	2	15	212	495	164	871
2022	2	16	186	506	164	856
2022	2	17	227	413	164	804
2022	2	18	269	376	164	809
2022	2	19	143	296	164	604
2022	2	20	127	122	164	413
2022	2	21	162	280	164	606
2022	2	22	194	275	164	633
2022	2	23	204	195	164	563
2022	2	24	148	149	164	461
2022	2	25	173	170	164	508
2022	2	26	176	153	164	493
2022	2	27	157	81	164	402
2022	2	28	118	43	164	325
2022	3	1	136	160	131	426
2022	3	2	123	146	131	400
2022	3	3	120	116	131	367
2022	3	4	125	100	131	356
2022	3	5	96	69	131	296
2022	3	6	58	64	131	253
2022	3	7	77	113	131	320
2022	3	8	125	162	131	417
2022	3	9	137	119	131	386
2022	3	10	90	96	131	316
2022	3	11	107	109	131	347
2022	3	12	85	76	131	291
2022	3	13	36	67	131	234
2022	3	14	78	78	131	287
2022	3	15	87	91	131	309
2022	3	16	81	79	131	290
2022	3	17	87	95	131	312
2022	3	18	123	106	131	360
2022	3	19	131	78	131	340
2022	3	20	94	67	131	292

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	3	21	112	98	131	341
2022	3	22	119	87	131	336
2022	3	23	130	79	131	339
2022	3	24	100	80	131	311
2022	3	25	92	55	131	278
2022	3	26	156	49	131	335
2022	3	27	145	72	131	348
2022	3	28	114	87	131	331
2022	3	29	133	121	131	385
2022	3	30	153	177	131	461
2022	3	31	147	154	131	431
2022	4	1	78	98	129	305
2022	4	2	59	61	129	249
2022	4	3	50	60	129	239
2022	4	4	78	69	129	276
2022	4	5	81	42	129	252
2022	4	6	72	45	129	246
2022	4	7	58	57	129	245
2022	4	8	71	59	129	260
2022	4	9	56	53	129	238
2022	4	10	54	60	129	243
2022	4	11	84	70	129	283
2022	4	12	71	34	129	235
2022	4	13	83	54	129	267
2022	4	14	100	60	129	290
2022	4	15	75	71	129	275
2022	4	16	56	56	129	241
2022	4	17	39	53	129	221
2022	4	18	53	66	129	249
2022	4	19	81	63	129	274
2022	4	20	107	45	129	282
2022	4	21	88	47	129	264
2022	4	22	81	68	129	279
2022	4	23	57	63	129	249
2022	4	24	58	41	129	229
2022	4	25	94	51	129	275
2022	4	26	88	69	129	286
2022	4	27	87	86	129	303
2022	4	28	78	73	129	280
2022	4	29	78	71	129	279
2022	4	30	66	59	129	254
2022	5	1	54	53	138	245

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	5	2	57	88	138	283
2022	5	3	57	51	138	246
2022	5	4	63	47	138	248
2022	5	5	86	78	138	302
2022	5	6	79	81	138	298
2022	5	7	69	46	138	253
2022	5	8	51	42	138	231
2022	5	9	71	47	138	256
2022	5	10	69	70	138	276
2022	5	11	66	73	138	277
2022	5	12	57	58	138	253
2022	5	13	70	59	138	267
2022	5	14	40	37	138	214
2022	5	15	28	45	138	210
2022	5	16	41	72	138	251
2022	5	17	45	63	138	247
2022	5	18	47	43	138	228
2022	5	19	44	68	138	249
2022	5	20	44	66	138	248
2022	5	21	53	40	138	231
2022	5	22	37	24	138	199
2022	5	23	36	39	138	213
2022	5	24	55	111	138	304
2022	5	25	36	103	138	277
2022	5	26	42	42	138	222
2022	5	27	45	52	138	234
2022	5	28	36	54	138	228
2022	5	29	25	48	138	211
2022	5	30	37	55	138	230
2022	5	31	41	26	138	206
2022	6	1	71	77	159	308
2022	6	2	44	97	159	300
2022	6	3	38	187	159	385
2022	6	4	33	136	159	328
2022	6	5	39	94	159	292
2022	6	6	69	93	159	322
2022	6	7	44	60	159	264
2022	6	8	61	117	159	337
2022	6	9	45	138	159	343
2022	6	10	55	138	159	352
2022	6	11	50	115	159	324
2022	6	12	35	73	159	268

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	6	13	41	99	159	299
2022	6	14	54	109	159	323
2022	6	15	58	146	159	364
2022	6	16	43	101	159	303
2022	6	17	67	111	159	337
2022	6	18	77	102	159	339
2022	6	19	50	72	159	282
2022	6	20	67	123	159	349
2022	6	21	50	134	159	344
2022	6	22	51	121	159	332
2022	6	23	59	150	159	368
2022	6	24	56	178	159	393
2022	6	25	45	148	159	353
2022	6	26	34	108	159	302
2022	6	27	59	100	159	318
2022	6	28	70	149	159	379
2022	6	29	63	137	159	359
2022	6	30	98	134	159	392
2022	7	1	109	231	164	504
2022	7	2	106	228	164	497
2022	7	3	103	241	164	507
2022	7	4	200	236	164	599
2022	7	5	362	356	164	881
2022	7	6	324	342	164	830
2022	7	7	329	381	164	873
2022	7	8	172	288	164	624
2022	7	9	103	179	164	446
2022	7	10	83	173	164	420
2022	7	11	160	314	164	637
2022	7	12	123	267	164	553
2022	7	13	120	165	164	448
2022	7	14	152	228	164	543
2022	7	15	228	296	164	688
2022	7	16	204	265	164	632
2022	7	17	119	193	164	476
2022	7	18	156	283	164	602
2022	7	19	95	178	164	437
2022	7	20	103	199	164	466
2022	7	21	111	267	164	541
2022	7	22	195	399	164	758
2022	7	23	159	266	164	589
2022	7	24	131	205	164	500

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	7	25	283	280	164	726
2022	7	26	315	307	164	785
2022	7	27	342	453	164	958
2022	7	28	371	506	164	1,040
2022	7	29	308	398	164	870
2022	7	30	129	188	164	481
2022	7	31	106	97	164	366
2022	8	1	181	340	188	709
2022	8	2	209	409	188	805
2022	8	3	280	429	188	896
2022	8	4	148	382	188	719
2022	8	5	132	304	188	623
2022	8	6	92	185	188	465
2022	8	7	98	241	188	526
2022	8	8	115	292	188	595
2022	8	9	110	290	188	589
2022	8	10	168	339	188	695
2022	8	11	135	324	188	646
2022	8	12	161	352	188	701
2022	8	13	118	235	188	541
2022	8	14	141	258	188	587
2022	8	15	330	428	188	946
2022	8	16	352	427	188	966
2022	8	17	331	436	188	955
2022	8	18	248	392	188	828
2022	8	19	180	320	188	688
2022	8	20	85	252	188	525
2022	8	21	155	220	188	563
2022	8	22	344	358	188	890
2022	8	23	360	453	188	1,002
2022	8	24	339	519	188	1,046
2022	8	25	353	574	188	1,115
2022	8	26	336	436	188	960
2022	8	27	164	147	188	498
2022	8	28	128	171	188	487
2022	8	29	165	279	188	632
2022	8	30	303	471	188	962
2022	8	31	354	524	188	1,066
2022	9	1	342	473	186	1,001
2022	9	2	356	571	186	1,113
2022	9	3	242	381	186	809
2022	9	4	86	76	186	348

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	9	5	171	177	186	534
2022	9	6	376	425	186	988
2022	9	7	285	480	186	951
2022	9	8	290	494	186	970
2022	9	9	346	516	186	1,048
2022	9	10	220	261	186	667
2022	9	11	112	162	186	460
2022	9	12	218	318	186	722
2022	9	13	346	527	186	1,059
2022	9	14	362	540	186	1,088
2022	9	15	274	356	186	816
2022	9	16	254	266	186	707
2022	9	17	151	93	186	430
2022	9	18	118	101	186	405
2022	9	19	257	286	186	729
2022	9	20	289	409	186	885
2022	9	21	330	394	186	911
2022	9	22	342	368	186	896
2022	9	23	290	227	186	703
2022	9	24	223	194	186	603
2022	9	25	180	162	186	528
2022	9	26	239	218	186	643
2022	9	27	258	278	186	722
2022	9	28	240	338	186	764
2022	9	29	287	421	186	895
2022	9	30	220	513	186	919
2022	10	1	101	267	174	541
2022	10	2	163	166	174	503
2022	10	3	333	283	174	790
2022	10	4	258	312	174	744
2022	10	5	217	254	174	644
2022	10	6	167	253	174	594
2022	10	7	157	228	174	559
2022	10	8	98	168	174	440
2022	10	9	128	185	174	487
2022	10	10	241	243	174	658
2022	10	11	235	205	174	615
2022	10	12	303	249	174	726
2022	10	13	224	241	174	639
2022	10	14	155	272	174	601
2022	10	15	94	145	174	412
2022	10	16	72	158	174	404

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	10	17	142	277	174	593
2022	10	18	267	327	174	768
2022	10	19	246	323	174	743
2022	10	20	238	288	174	700
2022	10	21	225	197	174	596
2022	10	22	136	140	174	449
2022	10	23	173	209	174	556
2022	10	24	264	289	174	727
2022	10	25	221	285	174	680
2022	10	26	143	213	174	530
2022	10	27	182	191	174	547
2022	10	28	231	188	174	593
2022	10	29	204	134	174	513
2022	10	30	199	198	174	571
2022	10	31	284	235	174	693
2022	11	1	188	212	142	542
2022	11	2	177	250	142	569
2022	11	3	203	333	142	678
2022	11	4	169	283	142	594
2022	11	5	155	293	142	591
2022	11	6	166	409	142	717
2022	11	7	172	494	142	809
2022	11	8	239	477	142	858
2022	11	9	224	470	142	836
2022	11	10	197	493	142	832
2022	11	11	176	516	142	834
2022	11	12	118	131	142	392
2022	11	13	65	54	142	261
2022	11	14	152	165	142	459
2022	11	15	258	299	142	699
2022	11	16	203	465	142	810
2022	11	17	221	499	142	862
2022	11	18	258	491	142	891
2022	11	19	194	330	142	666
2022	11	20	174	235	142	551
2022	11	21	215	308	142	666
2022	11	22	273	335	142	750
2022	11	23	252	312	142	706
2022	11	24	210	212	142	564
2022	11	25	169	171	142	482
2022	11	26	150	162	142	455
2022	11	27	119	118	142	379

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2022	11	28	177	193	142	512
2022	11	29	234	273	142	649
2022	11	30	272	340	142	754
2022	12	1	227	483	149	859
2022	12	2	204	519	149	873
2022	12	3	184	449	149	782
2022	12	4	156	158	149	464
2022	12	5	173	141	149	463
2022	12	6	218	247	149	615
2022	12	7	233	349	149	732
2022	12	8	256	433	149	838
2022	12	9	241	533	149	923
2022	12	10	221	378	149	749
2022	12	11	154	261	149	564
2022	12	12	197	342	149	688
2022	12	13	207	373	149	729
2022	12	14	341	531	149	1,021
2022	12	15	418	540	149	1,108
2022	12	16	312	562	149	1,023
2022	12	17	219	499	149	868
2022	12	18	177	390	149	717
2022	12	19	223	400	149	773
2022	12	20	269	357	149	776
2022	12	21	255	408	149	812
2022	12	22	216	435	149	801
2022	12	23	353	434	149	937
2022	12	24	336	377	149	862
2022	12	25	282	399	149	830
2022	12	26	311	456	149	916
2022	12	27	267	417	149	834
2022	12	28	132	312	149	594
2022	12	29	221	421	149	792
2022	12	30	234	509	149	892
2022	12	31	133	144	149	427
2023	1	1	63	420	140	623
2023	1	2	89	440	140	670
2023	1	3	91	446	140	678
2023	1	4	70	364	140	574
2023	1	5	81	308	140	530
2023	1	6	60	181	140	381
2023	1	7	44	220	140	404
2023	1	8	37	287	140	464

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	1	9	61	359	140	560
2023	1	10	74	403	140	617
2023	1	11	93	404	140	637
2023	1	12	106	418	140	664
2023	1	13	90	374	140	605
2023	1	14	82	226	140	449
2023	1	15	42	223	140	405
2023	1	16	79	476	140	696
2023	1	17	72	440	140	653
2023	1	18	58	343	140	541
2023	1	19	96	435	140	672
2023	1	20	89	485	140	714
2023	1	21	60	317	140	518
2023	1	22	66	298	140	505
2023	1	23	92	406	140	638
2023	1	24	110	480	140	730
2023	1	25	104	487	140	731
2023	1	26	84	500	140	725
2023	1	27	74	478	140	692
2023	1	28	58	229	140	428
2023	1	29	42	67	140	249
2023	1	30	66	142	140	348
2023	1	31	88	358	140	587
2023	2	1	79	224	164	467
2023	2	2	75	205	164	444
2023	2	3	78	215	164	457
2023	2	4	46	97	164	308
2023	2	5	33	93	164	290
2023	2	6	59	211	164	434
2023	2	7	69	272	164	505
2023	2	8	83	309	164	556
2023	2	9	83	388	164	636
2023	2	10	84	441	164	690
2023	2	11	68	329	164	560
2023	2	12	65	360	164	589
2023	2	13	92	478	164	734
2023	2	14	96	495	164	756
2023	2	15	96	502	164	761
2023	2	16	90	503	164	757
2023	2	17	90	398	164	652
2023	2	18	73	260	164	497
2023	2	19	55	179	164	398

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	2	20	59	201	164	423
2023	2	21	60	312	164	536
2023	2	22	83	267	164	514
2023	2	23	81	198	164	444
2023	2	24	73	67	164	304
2023	2	25	56	94	164	313
2023	2	26	40	196	164	400
2023	2	27	64	94	164	322
2023	2	28	50	35	164	250
2023	3	1	57	161	131	349
2023	3	2	57	132	131	319
2023	3	3	55	105	131	291
2023	3	4	42	95	131	268
2023	3	5	26	106	131	262
2023	3	6	51	96	131	277
2023	3	7	56	137	131	324
2023	3	8	59	159	131	348
2023	3	9	54	107	131	291
2023	3	10	42	76	131	249
2023	3	11	40	98	131	268
2023	3	12	36	100	131	266
2023	3	13	36	105	131	271
2023	3	14	41	109	131	280
2023	3	15	59	110	131	300
2023	3	16	56	109	131	296
2023	3	17	53	104	131	288
2023	3	18	38	80	131	249
2023	3	19	31	90	131	252
2023	3	20	43	116	131	290
2023	3	21	52	109	131	292
2023	3	22	55	104	131	290
2023	3	23	58	93	131	282
2023	3	24	50	66	131	247
2023	3	25	32	95	131	257
2023	3	26	30	120	131	281
2023	3	27	48	109	131	287
2023	3	28	49	87	131	266
2023	3	29	45	89	131	265
2023	3	30	51	92	131	273
2023	3	31	50	88	131	268
2023	4	1	33	90	129	253
2023	4	2	25	45	129	199

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	4	3	55	55	129	240
2023	4	4	47	59	129	236
2023	4	5	41	59	129	230
2023	4	6	41	65	129	235
2023	4	7	38	69	129	237
2023	4	8	31	59	129	219
2023	4	9	29	47	129	206
2023	4	10	39	62	129	231
2023	4	11	49	47	129	225
2023	4	12	54	48	129	232
2023	4	13	54	47	129	231
2023	4	14	54	49	129	232
2023	4	15	36	66	129	231
2023	4	16	24	73	129	226
2023	4	17	41	95	129	265
2023	4	18	42	67	129	238
2023	4	19	44	87	129	260
2023	4	20	59	73	129	261
2023	4	21	56	56	129	241
2023	4	22	31	53	129	213
2023	4	23	24	60	129	213
2023	4	24	41	91	129	262
2023	4	25	47	74	129	250
2023	4	26	46	117	129	292
2023	4	27	43	89	129	261
2023	4	28	45	54	129	228
2023	4	29	35	47	129	211
2023	4	30	24	33	129	186
2023	5	1	39	50	138	227
2023	5	2	42	58	138	238
2023	5	3	42	39	138	219
2023	5	4	46	69	138	253
2023	5	5	39	74	138	251
2023	5	6	39	70	138	247
2023	5	7	27	58	138	223
2023	5	8	37	33	138	208
2023	5	9	42	47	138	226
2023	5	10	36	34	138	208
2023	5	11	41	45	138	223
2023	5	12	35	51	138	224
2023	5	13	33	64	138	235
2023	5	14	25	65	138	227

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	5	15	36	73	138	247
2023	5	16	41	64	138	242
2023	5	17	40	39	138	217
2023	5	18	40	61	138	239
2023	5	19	38	64	138	241
2023	5	20	35	62	138	234
2023	5	21	26	50	138	214
2023	5	22	36	66	138	240
2023	5	23	37	85	138	260
2023	5	24	39	90	138	267
2023	5	25	34	81	138	252
2023	5	26	36	49	138	223
2023	5	27	34	77	138	249
2023	5	28	27	54	138	218
2023	5	29	41	54	138	233
2023	5	30	39	110	138	287
2023	5	31	37	28	138	202
2023	6	1	41	88	159	288
2023	6	2	38	191	159	388
2023	6	3	36	156	159	351
2023	6	4	30	76	159	265
2023	6	5	38	126	159	324
2023	6	6	43	112	159	315
2023	6	7	43	66	159	268
2023	6	8	43	105	159	308
2023	6	9	49	172	159	380
2023	6	10	38	162	159	359
2023	6	11	27	65	159	252
2023	6	12	42	97	159	298
2023	6	13	43	114	159	317
2023	6	14	40	121	159	320
2023	6	15	35	116	159	310
2023	6	16	40	125	159	324
2023	6	17	35	138	159	333
2023	6	18	28	118	159	305
2023	6	19	40	101	159	300
2023	6	20	41	199	159	399
2023	6	21	41	106	159	306
2023	6	22	39	104	159	303
2023	6	23	42	117	159	319
2023	6	24	35	140	159	335
2023	6	25	27	135	159	321

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	6	26	39	134	159	333
2023	6	27	42	142	159	344
2023	6	28	45	147	159	352
2023	6	29	34	152	159	346
2023	6	30	39	147	159	346
2023	7	1	35	246	164	445
2023	7	2	34	250	164	447
2023	7	3	58	318	164	540
2023	7	4	72	283	164	518
2023	7	5	86	357	164	606
2023	7	6	78	349	164	591
2023	7	7	77	367	164	608
2023	7	8	43	275	164	481
2023	7	9	28	148	164	339
2023	7	10	52	182	164	398
2023	7	11	61	332	164	557
2023	7	12	49	285	164	498
2023	7	13	47	162	164	373
2023	7	14	57	210	164	431
2023	7	15	54	263	164	481
2023	7	16	47	234	164	444
2023	7	17	67	294	164	525
2023	7	18	49	286	164	499
2023	7	19	41	197	164	401
2023	7	20	53	221	164	438
2023	7	21	49	264	164	476
2023	7	22	43	245	164	451
2023	7	23	41	257	164	462
2023	7	24	75	309	164	547
2023	7	25	81	375	164	619
2023	7	26	80	417	164	660
2023	7	27	79	483	164	726
2023	7	28	63	441	164	667
2023	7	29	51	139	164	354
2023	7	30	40	152	164	356
2023	7	31	55	224	164	442
2023	8	1	62	353	188	603
2023	8	2	61	471	188	720
2023	8	3	57	355	188	600
2023	8	4	62	381	188	631
2023	8	5	43	274	188	505
2023	8	6	37	163	188	388

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	8	7	60	333	188	580
2023	8	8	49	374	188	610
2023	8	9	46	278	188	512
2023	8	10	54	265	188	507
2023	8	11	61	322	188	571
2023	8	12	43	252	188	482
2023	8	13	37	278	188	503
2023	8	14	53	345	188	586
2023	8	15	48	299	188	536
2023	8	16	78	425	188	691
2023	8	17	80	462	188	730
2023	8	18	65	386	188	639
2023	8	19	49	251	188	488
2023	8	20	36	222	188	446
2023	8	21	79	429	188	696
2023	8	22	98	499	188	785
2023	8	23	99	473	188	760
2023	8	24	97	536	188	821
2023	8	25	77	422	188	687
2023	8	26	56	277	188	521
2023	8	27	36	157	188	382
2023	8	28	60	266	188	513
2023	8	29	59	315	188	562
2023	8	30	64	446	188	698
2023	8	31	107	563	188	859
2023	9	1	102	526	186	814
2023	9	2	67	417	186	670
2023	9	3	43	186	186	416
2023	9	4	53	126	186	365
2023	9	5	65	328	186	579
2023	9	6	77	426	186	690
2023	9	7	76	325	186	587
2023	9	8	93	478	186	757
2023	9	9	57	194	186	438
2023	9	10	43	172	186	401
2023	9	11	50	170	186	406
2023	9	12	69	262	186	518
2023	9	13	78	438	186	702
2023	9	14	93	560	186	839
2023	9	15	82	323	186	591
2023	9	16	48	73	186	308
2023	9	17	39	67	186	292

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	9	18	65	321	186	572
2023	9	19	73	181	186	440
2023	9	20	88	260	186	534
2023	9	21	87	293	186	566
2023	9	22	81	264	186	530
2023	9	23	62	229	186	477
2023	9	24	49	160	186	395
2023	9	25	85	224	186	495
2023	9	26	76	245	186	508
2023	9	27	72	261	186	520
2023	9	28	58	256	186	500
2023	9	29	62	287	186	535
2023	9	30	64	235	186	486
2023	10	1	46	195	174	415
2023	10	2	79	315	174	567
2023	10	3	88	344	174	606
2023	10	4	80	346	174	600
2023	10	5	72	287	174	533
2023	10	6	68	287	174	528
2023	10	7	57	236	174	467
2023	10	8	46	270	174	490
2023	10	9	79	276	174	528
2023	10	10	93	303	174	570
2023	10	11	75	259	174	508
2023	10	12	79	335	174	587
2023	10	13	87	284	174	544
2023	10	14	71	233	174	477
2023	10	15	46	199	174	418
2023	10	16	50	231	174	456
2023	10	17	46	258	174	477
2023	10	18	70	323	174	567
2023	10	19	82	319	174	575
2023	10	20	62	252	174	489
2023	10	21	39	135	174	347
2023	10	22	38	143	174	354
2023	10	23	57	400	174	631
2023	10	24	70	512	174	756
2023	10	25	86	392	174	652
2023	10	26	60	233	174	467
2023	10	27	47	174	174	395
2023	10	28	44	116	174	334
2023	10	29	35	146	174	355

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	10	30	52	273	174	499
2023	10	31	84	266	174	524
2023	11	1	76	212	142	431
2023	11	2	81	149	142	372
2023	11	3	71	244	142	457
2023	11	4	46	124	142	312
2023	11	5	55	259	142	456
2023	11	6	79	420	142	642
2023	11	7	76	410	142	628
2023	11	8	70	422	142	634
2023	11	9	76	436	142	654
2023	11	10	64	452	142	659
2023	11	11	71	276	142	489
2023	11	12	46	76	142	265
2023	11	13	51	33	142	225
2023	11	14	56	105	142	303
2023	11	15	72	173	142	387
2023	11	16	82	369	142	594
2023	11	17	92	487	142	721
2023	11	18	68	269	142	478
2023	11	19	56	195	142	394
2023	11	20	76	200	142	418
2023	11	21	88	281	142	512
2023	11	22	97	466	142	705
2023	11	23	93	319	142	554
2023	11	24	80	214	142	436
2023	11	25	52	208	142	402
2023	11	26	55	261	142	458
2023	11	27	82	238	142	462
2023	11	28	81	242	142	466
2023	11	29	84	261	142	488
2023	11	30	83	386	142	611
2023	12	1	83	510	149	742
2023	12	2	75	499	149	724
2023	12	3	54	345	149	549
2023	12	4	72	258	149	479
2023	12	5	69	185	149	403
2023	12	6	71	253	149	474
2023	12	7	85	344	149	578
2023	12	8	100	482	149	731
2023	12	9	86	503	149	738
2023	12	10	62	372	149	583

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2023	12	11	70	324	149	543
2023	12	12	76	361	149	586
2023	12	13	76	400	149	626
2023	12	14	114	528	149	792
2023	12	15	111	549	149	809
2023	12	16	78	536	149	764
2023	12	17	68	499	149	716
2023	12	18	100	456	149	705
2023	12	19	107	412	149	668
2023	12	20	85	370	149	604
2023	12	21	81	462	149	692
2023	12	22	76	465	149	690
2023	12	23	90	424	149	663
2023	12	24	99	374	149	622
2023	12	25	102	396	149	648
2023	12	26	115	462	149	726
2023	12	27	89	418	149	656
2023	12	28	76	295	149	520
2023	12	29	79	382	149	611
2023	12	30	68	350	149	568
2023	12	31	28	125	149	302
2024	1	1	59	303	140	503
2024	1	2	76	435	140	652
2024	1	3	67	355	140	562
2024	1	4	79	257	140	476
2024	1	5	76	337	140	554
2024	1	6	39	195	140	375
2024	1	7	35	201	140	377
2024	1	8	56	309	140	505
2024	1	9	61	351	140	552
2024	1	10	72	406	140	618
2024	1	11	86	433	140	660
2024	1	12	79	402	140	622
2024	1	13	50	270	140	460
2024	1	14	42	220	140	403
2024	1	15	69	230	140	440
2024	1	16	76	412	140	628
2024	1	17	79	418	140	637
2024	1	18	55	290	140	485
2024	1	19	64	394	140	599
2024	1	20	52	403	140	596
2024	1	21	54	284	140	479

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	1	22	84	316	140	540
2024	1	23	82	360	140	582
2024	1	24	78	408	140	626
2024	1	25	77	444	140	662
2024	1	26	61	500	140	702
2024	1	27	69	376	140	586
2024	1	28	48	267	140	456
2024	1	29	56	218	140	415
2024	1	30	63	242	140	445
2024	1	31	66	410	140	616
2024	2	1	59	219	164	443
2024	2	2	56	173	164	393
2024	2	3	46	192	164	403
2024	2	4	33	117	164	313
2024	2	5	56	159	164	379
2024	2	6	64	163	164	391
2024	2	7	66	266	164	496
2024	2	8	73	346	164	583
2024	2	9	70	343	164	577
2024	2	10	59	228	164	451
2024	2	11	53	222	164	440
2024	2	12	68	325	164	557
2024	2	13	62	341	164	567
2024	2	14	73	345	164	582
2024	2	15	78	357	164	598
2024	2	16	77	363	164	604
2024	2	17	65	262	164	491
2024	2	18	57	276	164	497
2024	2	19	74	254	164	491
2024	2	20	70	150	164	384
2024	2	21	63	213	164	441
2024	2	22	56	199	164	419
2024	2	23	48	129	164	340
2024	2	24	46	26	164	237
2024	2	25	36	55	164	255
2024	2	26	54	117	164	335
2024	2	27	45	43	164	253
2024	2	28	44	17	164	224
2024	2	29	56	104	164	324
2024	3	1	55	119	131	304
2024	3	2	47	74	131	251
2024	3	3	35	118	131	284

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	3	4	42	144	131	316
2024	3	5	56	100	131	287
2024	3	6	57	114	131	301
2024	3	7	53	130	131	313
2024	3	8	49	105	131	284
2024	3	9	40	95	131	266
2024	3	10	37	101	131	269
2024	3	11	37	135	131	303
2024	3	12	46	120	131	296
2024	3	13	40	115	131	285
2024	3	14	42	106	131	278
2024	3	15	32	74	131	237
2024	3	16	43	73	131	246
2024	3	17	37	86	131	254
2024	3	18	55	127	131	313
2024	3	19	59	104	131	294
2024	3	20	58	94	131	282
2024	3	21	56	83	131	270
2024	3	22	51	93	131	275
2024	3	23	40	103	131	274
2024	3	24	29	84	131	244
2024	3	25	43	98	131	271
2024	3	26	46	100	131	277
2024	3	27	52	86	131	269
2024	3	28	49	82	131	262
2024	3	29	48	95	131	273
2024	3	30	39	122	131	291
2024	3	31	27	106	131	264
2024	4	1	35	108	129	272
2024	4	2	47	87	129	263
2024	4	3	46	75	129	251
2024	4	4	38	63	129	230
2024	4	5	36	60	129	225
2024	4	6	29	58	129	216
2024	4	7	25	55	129	209
2024	4	8	41	68	129	238
2024	4	9	59	63	129	251
2024	4	10	44	59	129	233
2024	4	11	50	46	129	225
2024	4	12	54	51	129	234
2024	4	13	48	51	129	228
2024	4	14	24	60	129	214

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	4	15	38	74	129	241
2024	4	16	42	58	129	229
2024	4	17	43	55	129	228
2024	4	18	52	67	129	248
2024	4	19	40	50	129	219
2024	4	20	48	53	129	231
2024	4	21	27	88	129	244
2024	4	22	39	84	129	252
2024	4	23	48	108	129	285
2024	4	24	46	55	129	231
2024	4	25	47	49	129	225
2024	4	26	41	48	129	218
2024	4	27	34	41	129	204
2024	4	28	25	61	129	215
2024	4	29	41	67	129	237
2024	4	30	60	70	129	260
2024	5	1	47	87	138	271
2024	5	2	45	54	138	238
2024	5	3	43	67	138	249
2024	5	4	32	78	138	248
2024	5	5	25	51	138	213
2024	5	6	40	44	138	222
2024	5	7	42	40	138	220
2024	5	8	41	45	138	224
2024	5	9	40	46	138	223
2024	5	10	40	60	138	238
2024	5	11	31	58	138	227
2024	5	12	25	42	138	204
2024	5	13	38	55	138	232
2024	5	14	42	52	138	232
2024	5	15	41	50	138	228
2024	5	16	37	35	138	210
2024	5	17	37	50	138	225
2024	5	18	33	76	138	247
2024	5	19	25	49	138	212
2024	5	20	38	69	138	246
2024	5	21	37	73	138	247
2024	5	22	36	56	138	230
2024	5	23	40	41	138	219
2024	5	24	37	69	138	244
2024	5	25	34	74	138	247
2024	5	26	26	54	138	218

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	5	27	40	96	138	274
2024	5	28	43	92	138	273
2024	5	29	40	87	138	265
2024	5	30	39	45	138	222
2024	5	31	38	7	138	184
2024	6	1	37	161	159	357
2024	6	2	30	156	159	346
2024	6	3	43	133	159	335
2024	6	4	44	114	159	317
2024	6	5	43	104	159	307
2024	6	6	41	97	159	297
2024	6	7	43	125	159	327
2024	6	8	35	96	159	291
2024	6	9	28	87	159	274
2024	6	10	41	91	159	291
2024	6	11	39	89	159	288
2024	6	12	35	93	159	287
2024	6	13	40	75	159	274
2024	6	14	38	135	159	332
2024	6	15	34	81	159	275
2024	6	16	27	97	159	283
2024	6	17	40	147	159	346
2024	6	18	43	179	159	381
2024	6	19	40	136	159	335
2024	6	20	39	150	159	349
2024	6	21	39	106	159	305
2024	6	22	33	74	159	267
2024	6	23	27	123	159	310
2024	6	24	39	152	159	350
2024	6	25	43	156	159	358
2024	6	26	45	156	159	361
2024	6	27	40	170	159	370
2024	6	28	40	151	159	351
2024	6	29	29	135	159	323
2024	6	30	23	134	159	317
2024	7	1	53	235	164	451
2024	7	2	58	249	164	471
2024	7	3	61	224	164	449
2024	7	4	62	250	164	475
2024	7	5	54	241	164	459
2024	7	6	51	213	164	428
2024	7	7	28	251	164	443

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	7	8	43	249	164	456
2024	7	9	49	241	164	454
2024	7	10	47	254	164	464
2024	7	11	48	361	164	573
2024	7	12	46	190	164	399
2024	7	13	41	160	164	365
2024	7	14	42	233	164	439
2024	7	15	55	247	164	466
2024	7	16	61	285	164	510
2024	7	17	49	294	164	507
2024	7	18	48	241	164	452
2024	7	19	48	264	164	475
2024	7	20	37	188	164	389
2024	7	21	34	194	164	391
2024	7	22	62	352	164	578
2024	7	23	67	359	164	590
2024	7	24	75	344	164	582
2024	7	25	62	325	164	550
2024	7	26	46	223	164	433
2024	7	27	39	209	164	412
2024	7	28	41	242	164	447
2024	7	29	63	259	164	486
2024	7	30	59	268	164	491
2024	7	31	56	240	164	460
2024	8	1	62	344	188	594
2024	8	2	55	330	188	573
2024	8	3	36	242	188	466
2024	8	4	38	241	188	467
2024	8	5	55	290	188	533
2024	8	6	56	377	188	622
2024	8	7	49	329	188	566
2024	8	8	50	275	188	514
2024	8	9	47	296	188	531
2024	8	10	38	263	188	490
2024	8	11	39	243	188	470
2024	8	12	58	297	188	544
2024	8	13	51	304	188	543
2024	8	14	54	331	188	572
2024	8	15	84	348	188	621
2024	8	16	59	333	188	580
2024	8	17	44	257	188	489
2024	8	18	31	306	188	525

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	8	19	43	287	188	518
2024	8	20	60	326	188	574
2024	8	21	95	487	188	770
2024	8	22	92	477	188	756
2024	8	23	61	363	188	612
2024	8	24	48	236	188	472
2024	8	25	42	257	188	488
2024	8	26	53	383	188	624
2024	8	27	55	435	188	678
2024	8	28	59	415	188	663
2024	8	29	61	376	188	625
2024	8	30	60	301	188	549
2024	8	31	52	263	188	504
2024	9	1	70	443	186	699
2024	9	2	103	531	186	820
2024	9	3	69	225	186	480
2024	9	4	55	200	186	441
2024	9	5	75	268	186	530
2024	9	6	75	210	186	472
2024	9	7	54	226	186	466
2024	9	8	32	225	186	443
2024	9	9	59	247	186	492
2024	9	10	53	221	186	460
2024	9	11	81	380	186	648
2024	9	12	109	599	186	894
2024	9	13	94	445	186	725
2024	9	14	73	339	186	598
2024	9	15	73	261	186	520
2024	9	16	84	220	186	489
2024	9	17	84	166	186	437
2024	9	18	84	108	186	378
2024	9	19	87	157	186	430
2024	9	20	83	269	186	538
2024	9	21	64	198	186	448
2024	9	22	51	163	186	400
2024	9	23	66	248	186	500
2024	9	24	70	312	186	568
2024	9	25	79	263	186	529
2024	9	26	73	276	186	535
2024	9	27	49	242	186	477
2024	9	28	33	161	186	380
2024	9	29	46	282	186	514

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	9	30	65	472	186	723
2024	10	1	65	301	174	540
2024	10	2	70	281	174	525
2024	10	3	83	302	174	559
2024	10	4	66	189	174	429
2024	10	5	55	203	174	431
2024	10	6	45	313	174	532
2024	10	7	53	303	174	530
2024	10	8	50	328	174	553
2024	10	9	56	315	174	544
2024	10	10	52	242	174	468
2024	10	11	57	197	174	428
2024	10	12	42	196	174	412
2024	10	13	34	285	174	493
2024	10	14	53	219	174	446
2024	10	15	53	213	174	440
2024	10	16	63	244	174	481
2024	10	17	67	309	174	550
2024	10	18	60	243	174	477
2024	10	19	45	168	174	386
2024	10	20	40	170	174	383
2024	10	21	56	207	174	437
2024	10	22	66	272	174	511
2024	10	23	61	285	174	520
2024	10	24	62	267	174	502
2024	10	25	42	179	174	395
2024	10	26	48	147	174	369
2024	10	27	52	174	174	400
2024	10	28	53	220	174	447
2024	10	29	54	297	174	524
2024	10	30	56	224	174	454
2024	10	31	48	140	174	362
2024	11	1	65	102	142	309
2024	11	2	54	194	142	390
2024	11	3	42	285	142	469
2024	11	4	71	404	142	617
2024	11	5	85	491	142	718
2024	11	6	87	471	142	699
2024	11	7	83	476	142	701
2024	11	8	65	341	142	549
2024	11	9	61	305	142	508
2024	11	10	69	412	142	623

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	11	11	67	263	142	473
2024	11	12	55	111	142	308
2024	11	13	53	201	142	396
2024	11	14	69	318	142	529
2024	11	15	82	290	142	513
2024	11	16	70	347	142	559
2024	11	17	68	336	142	546
2024	11	18	86	276	142	504
2024	11	19	81	304	142	527
2024	11	20	77	394	142	613
2024	11	21	75	361	142	578
2024	11	22	73	386	142	602
2024	11	23	79	386	142	606
2024	11	24	71	346	142	559
2024	11	25	65	315	142	522
2024	11	26	52	235	142	429
2024	11	27	59	220	142	421
2024	11	28	79	278	142	500
2024	11	29	73	223	142	439
2024	11	30	76	364	142	583
2024	12	1	92	501	149	743
2024	12	2	91	527	149	767
2024	12	3	66	469	149	684
2024	12	4	63	311	149	523
2024	12	5	65	350	149	565
2024	12	6	75	397	149	621
2024	12	7	112	517	149	778
2024	12	8	90	558	149	798
2024	12	9	70	497	149	716
2024	12	10	59	492	149	700
2024	12	11	62	457	149	668
2024	12	12	71	482	149	703
2024	12	13	93	561	149	804
2024	12	14	100	588	149	838
2024	12	15	127	540	149	817
2024	12	16	125	595	149	869
2024	12	17	91	472	149	712
2024	12	18	95	513	149	757
2024	12	19	84	442	149	675
2024	12	20	80	310	149	539
2024	12	21	60	310	149	519
2024	12	22	100	474	149	723

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2024	12	23	126	411	149	686
2024	12	24	133	327	149	609
2024	12	25	108	542	149	799
2024	12	26	111	426	149	687
2024	12	27	72	273	149	494
2024	12	28	68	391	149	608
2024	12	29	83	519	149	751
2024	12	30	55	417	149	621
2024	12	31	81	446	149	676
2025	1	1	73	501	140	715
2025	1	2	66	475	140	682
2025	1	3	74	398	140	612
2025	1	4	50	212	140	403
2025	1	5	38	136	140	315
2025	1	6	51	219	140	410
2025	1	7	61	300	140	501
2025	1	8	63	331	140	535
2025	1	9	63	377	140	581
2025	1	10	60	381	140	581
2025	1	11	48	334	140	523
2025	1	12	41	261	140	442
2025	1	13	58	388	140	586
2025	1	14	61	353	140	555
2025	1	15	65	403	140	608
2025	1	16	52	383	140	576
2025	1	17	50	367	140	558
2025	1	18	48	354	140	542
2025	1	19	47	345	140	532
2025	1	20	64	431	140	636
2025	1	21	72	418	140	631
2025	1	22	82	373	140	594
2025	1	23	81	431	140	652
2025	1	24	77	486	140	703
2025	1	25	77	431	140	648
2025	1	26	45	406	140	592
2025	1	27	57	384	140	581
2025	1	28	58	215	140	414
2025	1	29	55	209	140	404
2025	1	30	61	269	140	470
2025	1	31	58	215	140	414
2025	2	1	45	170	164	379
2025	2	2	26	157	164	347

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	2	3	58	178	164	400
2025	2	4	57	183	164	404
2025	2	5	65	226	164	455
2025	2	6	64	265	164	492
2025	2	7	61	333	164	558
2025	2	8	49	171	164	383
2025	2	9	39	189	164	391
2025	2	10	58	335	164	557
2025	2	11	57	309	164	530
2025	2	12	57	396	164	617
2025	2	13	91	455	164	710
2025	2	14	79	489	164	732
2025	2	15	53	299	164	516
2025	2	16	45	242	164	452
2025	2	17	82	367	164	613
2025	2	18	69	271	164	503
2025	2	19	59	210	164	433
2025	2	20	54	197	164	415
2025	2	21	46	154	164	363
2025	2	22	43	50	164	257
2025	2	23	35	28	164	227
2025	2	24	56	125	164	345
2025	2	25	59	180	164	403
2025	2	26	57	148	164	369
2025	2	27	55	98	164	317
2025	2	28	51	119	164	334
2025	3	1	43	92	131	265
2025	3	2	31	82	131	244
2025	3	3	49	138	131	317
2025	3	4	55	162	131	347
2025	3	5	44	114	131	289
2025	3	6	57	97	131	284
2025	3	7	53	106	131	290
2025	3	8	42	90	131	262
2025	3	9	37	87	131	254
2025	3	10	38	113	131	281
2025	3	11	47	147	131	324
2025	3	12	40	132	131	302
2025	3	13	39	92	131	262
2025	3	14	37	106	131	273
2025	3	15	31	77	131	239
2025	3	16	24	85	131	240

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	3	17	55	114	131	300
2025	3	18	51	101	131	283
2025	3	19	57	97	131	284
2025	3	20	53	112	131	296
2025	3	21	57	124	131	312
2025	3	22	48	77	131	256
2025	3	23	26	91	131	247
2025	3	24	49	116	131	296
2025	3	25	39	72	131	242
2025	3	26	48	97	131	275
2025	3	27	56	99	131	285
2025	3	28	49	89	131	269
2025	3	29	40	84	131	254
2025	3	30	32	79	131	241
2025	3	31	46	115	131	291
2025	4	1	40	100	129	269
2025	4	2	41	78	129	248
2025	4	3	44	73	129	247
2025	4	4	41	54	129	225
2025	4	5	31	63	129	223
2025	4	6	24	70	129	223
2025	4	7	38	57	129	224
2025	4	8	42	71	129	242
2025	4	9	40	66	129	236
2025	4	10	43	57	129	229
2025	4	11	40	47	129	216
2025	4	12	29	36	129	195
2025	4	13	24	55	129	209
2025	4	14	41	69	129	239
2025	4	15	41	61	129	231
2025	4	16	40	59	129	229
2025	4	17	42	61	129	233
2025	4	18	39	49	129	217
2025	4	19	33	58	129	221
2025	4	20	25	56	129	210
2025	4	21	40	63	129	232
2025	4	22	43	84	129	256
2025	4	23	47	109	129	286
2025	4	24	44	72	129	245
2025	4	25	42	59	129	231
2025	4	26	30	49	129	209
2025	4	27	25	41	129	196

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	4	28	43	68	129	240
2025	4	29	47	83	129	260
2025	4	30	46	55	129	231
2025	5	1	42	57	138	238
2025	5	2	40	74	138	252
2025	5	3	33	70	138	241
2025	5	4	25	65	138	228
2025	5	5	36	49	138	222
2025	5	6	42	35	138	214
2025	5	7	41	42	138	221
2025	5	8	40	37	138	215
2025	5	9	40	50	138	228
2025	5	10	31	72	138	240
2025	5	11	25	69	138	232
2025	5	12	33	44	138	215
2025	5	13	37	69	138	244
2025	5	14	40	35	138	213
2025	5	15	37	56	138	231
2025	5	16	39	72	138	248
2025	5	17	34	60	138	231
2025	5	18	25	59	138	222
2025	5	19	39	82	138	259
2025	5	20	41	47	138	226
2025	5	21	38	54	138	231
2025	5	22	34	31	138	203
2025	5	23	33	48	138	219
2025	5	24	32	84	138	254
2025	5	25	25	79	138	241
2025	5	26	37	44	138	219
2025	5	27	41	85	138	264
2025	5	28	39	77	138	253
2025	5	29	43	75	138	255
2025	5	30	39	77	138	254
2025	5	31	30	20	138	188
2025	6	1	29	145	159	334
2025	6	2	38	132	159	329
2025	6	3	38	114	159	312
2025	6	4	36	74	159	269
2025	6	5	35	69	159	262
2025	6	6	40	159	159	359
2025	6	7	35	139	159	333
2025	6	8	27	77	159	263

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	6	9	39	135	159	333
2025	6	10	39	130	159	329
2025	6	11	39	106	159	304
2025	6	12	39	86	159	284
2025	6	13	41	97	159	298
2025	6	14	34	94	159	288
2025	6	15	26	90	159	276
2025	6	16	37	127	159	323
2025	6	17	38	130	159	328
2025	6	18	41	158	159	358
2025	6	19	36	118	159	314
2025	6	20	38	173	159	370
2025	6	21	33	135	159	328
2025	6	22	26	90	159	275
2025	6	23	40	98	159	298
2025	6	24	48	152	159	359
2025	6	25	46	156	159	361
2025	6	26	49	158	159	366
2025	6	27	43	192	159	394
2025	6	28	32	125	159	316
2025	6	29	26	112	159	298
2025	6	30	40	144	159	343
2025	7	1	46	242	164	452
2025	7	2	50	245	164	459
2025	7	3	43	303	164	510
2025	7	4	56	260	164	479
2025	7	5	53	221	164	437
2025	7	6	41	210	164	414
2025	7	7	43	241	164	447
2025	7	8	48	242	164	453
2025	7	9	44	235	164	443
2025	7	10	44	242	164	450
2025	7	11	44	387	164	594
2025	7	12	35	284	164	483
2025	7	13	26	99	164	289
2025	7	14	45	220	164	428
2025	7	15	64	246	164	474
2025	7	16	65	258	164	486
2025	7	17	45	248	164	456
2025	7	18	44	384	164	592
2025	7	19	31	245	164	440
2025	7	20	26	130	164	319

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	7	21	45	229	164	437
2025	7	22	57	242	164	463
2025	7	23	65	246	164	475
2025	7	24	69	263	164	495
2025	7	25	50	271	164	484
2025	7	26	35	231	164	429
2025	7	27	26	217	164	406
2025	7	28	59	246	164	468
2025	7	29	63	242	164	468
2025	7	30	63	242	164	469
2025	7	31	45	252	164	461
2025	8	1	56	335	188	579
2025	8	2	37	341	188	566
2025	8	3	27	270	188	486
2025	8	4	42	279	188	509
2025	8	5	54	271	188	513
2025	8	6	55	310	188	553
2025	8	7	48	298	188	533
2025	8	8	45	404	188	636
2025	8	9	35	260	188	483
2025	8	10	27	213	188	429
2025	8	11	44	300	188	532
2025	8	12	49	304	188	541
2025	8	13	59	301	188	547
2025	8	14	52	279	188	519
2025	8	15	49	288	188	525
2025	8	16	51	319	188	558
2025	8	17	42	301	188	531
2025	8	18	41	359	188	588
2025	8	19	45	266	188	499
2025	8	20	56	279	188	523
2025	8	21	60	289	188	537
2025	8	22	64	372	188	624
2025	8	23	38	323	188	549
2025	8	24	28	248	188	464
2025	8	25	64	282	188	534
2025	8	26	65	334	188	587
2025	8	27	67	393	188	648
2025	8	28	70	409	188	667
2025	8	29	58	317	188	563
2025	8	30	48	287	188	523
2025	8	31	39	319	188	546

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	9	1	62	469	186	717
2025	9	2	69	583	186	838
2025	9	3	68	475	186	729
2025	9	4	61	177	186	424
2025	9	5	64	174	186	425
2025	9	6	58	158	186	401
2025	9	7	59	181	186	425
2025	9	8	56	257	186	499
2025	9	9	62	285	186	534
2025	9	10	68	308	186	562
2025	9	11	61	314	186	560
2025	9	12	71	392	186	650
2025	9	13	60	381	186	627
2025	9	14	54	391	186	631
2025	9	15	73	395	186	654
2025	9	16	65	304	186	555
2025	9	17	64	186	186	436
2025	9	18	64	107	186	357
2025	9	19	69	153	186	408
2025	9	20	63	186	186	436
2025	9	21	50	228	186	464
2025	9	22	65	289	186	540
2025	9	23	68	309	186	563
2025	9	24	68	286	186	540
2025	9	25	88	324	186	599
2025	9	26	69	304	186	558
2025	9	27	53	250	186	488
2025	9	28	37	193	186	416
2025	9	29	60	247	186	493
2025	9	30	79	354	186	619
2025	10	1	62	305	174	541
2025	10	2	62	282	174	518
2025	10	3	65	266	174	505
2025	10	4	48	224	174	445
2025	10	5	37	233	174	443
2025	10	6	57	274	174	505
2025	10	7	61	260	174	495
2025	10	8	58	323	174	555
2025	10	9	68	269	174	511
2025	10	10	70	255	174	499
2025	10	11	46	178	174	397
2025	10	12	50	203	174	426

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	10	13	71	303	174	549
2025	10	14	72	324	174	569
2025	10	15	64	274	174	511
2025	10	16	54	256	174	484
2025	10	17	40	288	174	503
2025	10	18	40	295	174	508
2025	10	19	34	241	174	449
2025	10	20	50	270	174	494
2025	10	21	46	294	174	515
2025	10	22	48	294	174	516
2025	10	23	51	345	174	569
2025	10	24	59	345	174	578
2025	10	25	52	193	174	418
2025	10	26	30	116	174	320
2025	10	27	44	198	174	416
2025	10	28	48	284	174	506
2025	10	29	51	288	174	514
2025	10	30	56	330	174	560
2025	10	31	83	379	174	636
2025	11	1	47	181	142	370
2025	11	2	53	241	142	436
2025	11	3	67	374	142	583
2025	11	4	63	409	142	613
2025	11	5	70	497	142	709
2025	11	6	80	522	142	744
2025	11	7	74	509	142	725
2025	11	8	50	430	142	623
2025	11	9	44	401	142	587
2025	11	10	76	545	142	764
2025	11	11	77	531	142	750
2025	11	12	67	381	142	591
2025	11	13	53	203	142	398
2025	11	14	55	240	142	437
2025	11	15	48	231	142	421
2025	11	16	46	415	142	603
2025	11	17	68	520	142	730
2025	11	18	76	515	142	733
2025	11	19	73	505	142	720
2025	11	20	83	399	142	624
2025	11	21	92	376	142	611
2025	11	22	81	446	142	669
2025	11	23	82	389	142	613

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2025	11	24	104	327	142	573
2025	11	25	63	485	142	690
2025	11	26	68	545	142	755
2025	11	27	55	318	142	515
2025	11	28	58	324	142	524
2025	11	29	53	419	142	614
2025	11	30	62	483	142	687
2025	12	1	97	591	149	838
2025	12	2	109	566	149	824
2025	12	3	89	548	149	786
2025	12	4	63	473	149	685
2025	12	5	55	371	149	575
2025	12	6	49	374	149	572
2025	12	7	55	459	149	663
2025	12	8	120	559	149	829
2025	12	9	122	579	149	850
2025	12	10	100	540	149	789
2025	12	11	62	447	149	658
2025	12	12	61	481	149	691
2025	12	13	54	457	149	660
2025	12	14	99	570	149	819
2025	12	15	133	599	149	882
2025	12	16	146	618	149	914
2025	12	17	112	562	149	824
2025	12	18	119	552	149	820
2025	12	19	108	450	149	708
2025	12	20	61	410	149	621
2025	12	21	59	502	149	711
2025	12	22	94	533	149	777
2025	12	23	139	488	149	776
2025	12	24	157	450	149	757
2025	12	25	128	444	149	721
2025	12	26	133	558	149	840
2025	12	27	103	448	149	700
2025	12	28	43	375	149	567
2025	12	29	71	535	149	755
2025	12	30	84	543	149	777
2025	12	31	56	379	149	584
2026	1	1	71	500	140	712
2026	1	2	74	513	140	727
2026	1	3	64	439	140	644
2026	1	4	46	417	140	604

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	1	5	63	276	140	479
2026	1	6	53	193	140	386
2026	1	7	56	224	140	420
2026	1	8	66	343	140	549
2026	1	9	60	320	140	521
2026	1	10	49	360	140	549
2026	1	11	44	474	140	659
2026	1	12	74	443	140	658
2026	1	13	75	472	140	688
2026	1	14	67	440	140	647
2026	1	15	64	456	140	661
2026	1	16	63	487	140	691
2026	1	17	49	333	140	522
2026	1	18	36	288	140	464
2026	1	19	74	531	140	745
2026	1	20	81	538	140	759
2026	1	21	102	453	140	696
2026	1	22	101	384	140	625
2026	1	23	96	468	140	705
2026	1	24	77	484	140	701
2026	1	25	71	503	140	715
2026	1	26	89	552	140	781
2026	1	27	81	565	140	786
2026	1	28	67	443	140	651
2026	1	29	59	336	140	535
2026	1	30	53	301	140	494
2026	1	31	48	300	140	488
2026	2	1	38	176	164	378
2026	2	2	64	203	164	431
2026	2	3	74	169	164	407
2026	2	4	60	158	164	382
2026	2	5	62	184	164	410
2026	2	6	61	278	164	503
2026	2	7	50	294	164	507
2026	2	8	38	282	164	484
2026	2	9	53	496	164	713
2026	2	10	68	521	164	754
2026	2	11	72	488	164	724
2026	2	12	71	493	164	729
2026	2	13	89	496	164	748
2026	2	14	66	490	164	720
2026	2	15	43	443	164	650

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	2	16	61	480	164	705
2026	2	17	90	445	164	699
2026	2	18	90	406	164	660
2026	2	19	90	411	164	665
2026	2	20	62	364	164	590
2026	2	21	39	231	164	435
2026	2	22	37	181	164	382
2026	2	23	50	212	164	425
2026	2	24	58	182	164	404
2026	2	25	61	233	164	458
2026	2	26	59	289	164	513
2026	2	27	59	187	164	410
2026	2	28	39	64	164	267
2026	3	1	38	134	131	302
2026	3	2	49	165	131	344
2026	3	3	55	248	131	433
2026	3	4	54	207	131	391
2026	3	5	46	104	131	281
2026	3	6	54	85	131	270
2026	3	7	43	96	131	270
2026	3	8	33	110	131	273
2026	3	9	54	104	131	288
2026	3	10	44	114	131	289
2026	3	11	47	147	131	324
2026	3	12	49	111	131	290
2026	3	13	38	96	131	264
2026	3	14	30	97	131	257
2026	3	15	23	72	131	226
2026	3	16	39	87	131	257
2026	3	17	57	114	131	301
2026	3	18	50	196	131	377
2026	3	19	55	221	131	406
2026	3	20	49	209	131	389
2026	3	21	43	138	131	312
2026	3	22	30	89	131	250
2026	3	23	49	76	131	255
2026	3	24	48	100	131	278
2026	3	25	40	106	131	277
2026	3	26	49	130	131	310
2026	3	27	53	103	131	286
2026	3	28	40	76	131	246
2026	3	29	32	74	131	236

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	3	30	46	136	131	313
2026	3	31	47	148	131	326
2026	4	1	38	90	129	257
2026	4	2	53	67	129	250
2026	4	3	43	79	129	251
2026	4	4	38	65	129	232
2026	4	5	26	61	129	216
2026	4	6	36	58	129	223
2026	4	7	37	57	129	223
2026	4	8	40	62	129	232
2026	4	9	38	41	129	208
2026	4	10	42	76	129	247
2026	4	11	38	81	129	248
2026	4	12	30	39	129	197
2026	4	13	51	50	129	231
2026	4	14	59	76	129	263
2026	4	15	41	65	129	235
2026	4	16	40	53	129	223
2026	4	17	42	63	129	235
2026	4	18	35	64	129	228
2026	4	19	27	57	129	213
2026	4	20	41	64	129	235
2026	4	21	41	67	129	238
2026	4	22	40	98	129	267
2026	4	23	43	63	129	236
2026	4	24	42	67	129	238
2026	4	25	33	63	129	226
2026	4	26	26	60	129	216
2026	4	27	39	67	129	236
2026	4	28	42	72	129	244
2026	4	29	42	49	129	220
2026	4	30	60	60	129	249
2026	5	1	40	89	138	267
2026	5	2	32	65	138	235
2026	5	3	23	47	138	208
2026	5	4	39	40	138	217
2026	5	5	37	44	138	219
2026	5	6	56	62	138	256
2026	5	7	46	79	138	264
2026	5	8	39	61	138	238
2026	5	9	31	51	138	219
2026	5	10	22	44	138	204

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	5	11	39	49	138	225
2026	5	12	33	81	138	253
2026	5	13	35	62	138	235
2026	5	14	38	42	138	218
2026	5	15	35	67	138	240
2026	5	16	30	61	138	229
2026	5	17	25	47	138	209
2026	5	18	41	83	138	262
2026	5	19	40	61	138	239
2026	5	20	42	47	138	227
2026	5	21	41	76	138	255
2026	5	22	33	49	138	220
2026	5	23	28	52	138	218
2026	5	24	23	61	138	222
2026	5	25	34	46	138	218
2026	5	26	40	95	138	273
2026	5	27	41	69	138	248
2026	5	28	38	64	138	241
2026	5	29	40	91	138	268
2026	5	30	30	67	138	235
2026	5	31	22	17	138	176
2026	6	1	33	124	159	316
2026	6	2	30	125	159	314
2026	6	3	32	116	159	308
2026	6	4	33	114	159	306
2026	6	5	33	188	159	380
2026	6	6	29	146	159	334
2026	6	7	22	56	159	238
2026	6	8	38	106	159	303
2026	6	9	41	157	159	357
2026	6	10	39	134	159	332
2026	6	11	36	101	159	296
2026	6	12	35	130	159	325
2026	6	13	29	140	159	328
2026	6	14	23	43	159	225
2026	6	15	38	126	159	323
2026	6	16	42	123	159	324
2026	6	17	43	119	159	321
2026	6	18	46	136	159	341
2026	6	19	38	164	159	361
2026	6	20	29	150	159	338
2026	6	21	26	83	159	268

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	6	22	41	83	159	284
2026	6	23	46	133	159	338
2026	6	24	50	143	159	353
2026	6	25	52	160	159	371
2026	6	26	48	154	159	361
2026	6	27	35	111	159	305
2026	6	28	29	110	159	298
2026	6	29	42	150	159	351
2026	6	30	48	148	159	355
2026	7	1	43	252	164	459
2026	7	2	49	235	164	447
2026	7	3	60	276	164	499
2026	7	4	52	259	164	474
2026	7	5	39	215	164	418
2026	7	6	60	339	164	562
2026	7	7	67	357	164	587
2026	7	8	47	293	164	503
2026	7	9	47	244	164	454
2026	7	10	46	213	164	423
2026	7	11	37	385	164	585
2026	7	12	27	182	164	372
2026	7	13	42	176	164	382
2026	7	14	55	242	164	461
2026	7	15	65	248	164	477
2026	7	16	64	280	164	508
2026	7	17	42	290	164	495
2026	7	18	38	359	164	560
2026	7	19	26	167	164	357
2026	7	20	43	202	164	409
2026	7	21	46	226	164	436
2026	7	22	53	292	164	509
2026	7	23	63	369	164	596
2026	7	24	60	382	164	605
2026	7	25	41	273	164	478
2026	7	26	30	203	164	396
2026	7	27	60	290	164	514
2026	7	28	66	327	164	556
2026	7	29	63	308	164	535
2026	7	30	64	293	164	520
2026	7	31	58	299	164	520
2026	8	1	45	303	188	536
2026	8	2	39	307	188	534

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	8	3	59	295	188	542
2026	8	4	63	299	188	550
2026	8	5	52	319	188	559
2026	8	6	58	279	188	525
2026	8	7	55	341	188	584
2026	8	8	32	328	188	548
2026	8	9	25	224	188	437
2026	8	10	45	289	188	522
2026	8	11	64	301	188	553
2026	8	12	61	303	188	552
2026	8	13	61	301	188	549
2026	8	14	55	327	188	570
2026	8	15	44	273	188	506
2026	8	16	41	367	188	596
2026	8	17	63	495	188	746
2026	8	18	53	375	188	616
2026	8	19	47	275	188	510
2026	8	20	58	290	188	536
2026	8	21	65	337	188	590
2026	8	22	54	289	188	531
2026	8	23	42	273	188	502
2026	8	24	60	364	188	612
2026	8	25	66	410	188	664
2026	8	26	65	391	188	644
2026	8	27	64	416	188	669
2026	8	28	65	452	188	705
2026	8	29	43	293	188	524
2026	8	30	41	275	188	504
2026	8	31	60	418	188	666
2026	9	1	100	636	186	921
2026	9	2	80	582	186	848
2026	9	3	58	374	186	619
2026	9	4	60	281	186	527
2026	9	5	44	178	186	408
2026	9	6	47	184	186	417
2026	9	7	74	312	186	572
2026	9	8	70	379	186	635
2026	9	9	69	356	186	611
2026	9	10	63	302	186	552
2026	9	11	59	318	186	563
2026	9	12	49	327	186	562
2026	9	13	52	410	186	648

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	9	14	77	524	186	787
2026	9	15	78	485	186	749
2026	9	16	73	403	186	662
2026	9	17	68	232	186	487
2026	9	18	57	129	186	372
2026	9	19	53	90	186	330
2026	9	20	54	216	186	455
2026	9	21	72	407	186	665
2026	9	22	74	415	186	675
2026	9	23	74	410	186	671
2026	9	24	75	356	186	617
2026	9	25	85	366	186	637
2026	9	26	49	307	186	541
2026	9	27	38	259	186	483
2026	9	28	48	274	186	509
2026	9	29	67	380	186	634
2026	9	30	88	541	186	815
2026	10	1	63	338	174	575
2026	10	2	65	250	174	489
2026	10	3	52	239	174	465
2026	10	4	36	263	174	473
2026	10	5	59	319	174	552
2026	10	6	64	362	174	599
2026	10	7	64	343	174	580
2026	10	8	58	386	174	618
2026	10	9	55	338	174	567
2026	10	10	47	239	174	460
2026	10	11	32	238	174	444
2026	10	12	57	477	174	708
2026	10	13	62	386	174	621
2026	10	14	62	399	174	635
2026	10	15	60	363	174	597
2026	10	16	54	317	174	545
2026	10	17	32	252	174	458
2026	10	18	32	307	174	512
2026	10	19	57	405	174	636
2026	10	20	55	348	174	577
2026	10	21	50	350	174	574
2026	10	22	48	347	174	569
2026	10	23	44	400	174	618
2026	10	24	43	351	174	568
2026	10	25	44	226	174	444

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	10	26	48	210	174	432
2026	10	27	47	250	174	470
2026	10	28	51	318	174	542
2026	10	29	53	376	174	602
2026	10	30	53	434	174	661
2026	10	31	53	339	174	565
2026	11	1	40	245	142	427
2026	11	2	70	368	142	579
2026	11	3	65	475	142	681
2026	11	4	58	458	142	658
2026	11	5	67	502	142	711
2026	11	6	77	514	142	734
2026	11	7	63	448	142	653
2026	11	8	46	428	142	616
2026	11	9	78	505	142	725
2026	11	10	72	542	142	756
2026	11	11	76	534	142	752
2026	11	12	67	396	142	605
2026	11	13	53	146	142	341
2026	11	14	44	169	142	356
2026	11	15	42	307	142	491
2026	11	16	62	541	142	745
2026	11	17	72	542	142	756
2026	11	18	76	506	142	724
2026	11	19	74	531	142	746
2026	11	20	78	410	142	630
2026	11	21	63	345	142	550
2026	11	22	57	483	142	682
2026	11	23	100	456	142	697
2026	11	24	98	329	142	569
2026	11	25	77	511	142	730
2026	11	26	59	464	142	664
2026	11	27	54	393	142	589
2026	11	28	46	383	142	571
2026	11	29	43	479	142	664
2026	11	30	69	483	142	693
2026	12	1	88	595	149	832
2026	12	2	106	587	149	842
2026	12	3	85	548	149	783
2026	12	4	67	474	149	690
2026	12	5	46	320	149	515
2026	12	6	46	411	149	607

Annual, Monthly, and Daily Forecast of Electric Generation, Average Year, MDth/day

Year	Month	Day	Market-Responsive, LT, MDth/d	Market-Responsive, BB, MDth/d	Non-Market-Responsive, LT, MDth/d	Total EG, MDth/d
2026	12	7	81	550	149	780
2026	12	8	122	562	149	833
2026	12	9	118	577	149	844
2026	12	10	89	544	149	782
2026	12	11	60	474	149	683
2026	12	12	45	457	149	652
2026	12	13	53	532	149	735
2026	12	14	121	658	149	928
2026	12	15	135	718	149	1,003
2026	12	16	108	659	149	916
2026	12	17	94	568	149	811
2026	12	18	90	552	149	792
2026	12	19	70	437	149	657
2026	12	20	52	440	149	642
2026	12	21	97	523	149	770
2026	12	22	96	533	149	778
2026	12	23	134	486	149	770
2026	12	24	153	488	149	790
2026	12	25	122	441	149	713
2026	12	26	102	503	149	754
2026	12	27	60	423	149	633
2026	12	28	69	429	149	648
2026	12	29	75	542	149	766
2026	12	30	71	550	149	771
2026	12	31	45	404	149	599

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2A

ATTACHMENT C

PG&E’S RESPONSE TO TURN SET THREE, QUESTION 4

(6/29/2022)

PACIFIC GAS AND ELECTRIC COMPANY
GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	TURN_003-Q004		
PG&E File Name:	GTS-CARD-2023_DR_TURN_003-Q004		
Request Date:	May 20, 2022	Requester DR No.:	003
Date Sent:	June 29, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Patricia Gideon Todd Peterson Andrew Klingler	Requester:	Michel Peter Florio

QUESTION 004

At page 4-32, lines 1-3, PG&E states that

> "the CYPM forecast is based on the gas throughput forecast discussed in Chapters 2A and 2B, the CYPM forecast was revised to reflect the changes in the gas throughput forecast."

Please provide the complete calculations showing the translation of the throughput forecasts in Chapters 2A and 2B into the CYPM forecasts for core and noncore LT demand.

ANSWER 004

Attachment GTS-CARD-2023_DR_TURN_003-Q004Atch01 provides the calculations that show the translation of the monthly throughput forecasts into the CYPM forecasts for core and noncore LT demand. The peak month in each year is indicated in line 74 by yellow highlight and summarized in columns AZ through BC and columns BG through BJ. Adjustments for backbone customer classes which do not pay for the LT function, LT contract discounts, and employee discounts are provided in columns BL through BO. Adjusted CYPM volumes used for allocation are provided in columns BQ through BT.

The question requests PG&E to provide the "calculations showing the translation of the monthly throughput forecast" in Chapter 2A and 2B into the CYPM forecast. However, it is more accurate to say that the annual throughput forecast in Chapter 2B and the CYPM forecast are both derived from the same underlying monthly forecast, which includes the results from Chapter 2A as a component. This component can be seen in GTS-CARD-2023_DR_TURN_003-Q004Atch01 lines 46-49 and the first paragraph of this answer explains how the CYPM forecast is derived.

Attachment GTS-CARD-2023_DR_TURN_003-Q004Atch02.xlsx provides the calculations that show the translation of the monthly throughput forecast into the annual table(s) provided in testimony. The annual values are grouped in Jan-Dec sums of the monthly forecast, dividing by 365 (or 366 for 2024) to convert into "per day" values. This is illustrated in the attachment, providing the table on the left, the monthly values on the right, and annual sums with line references in between.

There is a slight discrepancy between the numbers in Table 2B-2 and the annual values calculated from the forecast file used for the CYPM due to an incorrect year index used for building electrification in one of the files. PG&E anticipates submitting errata testimony addressing this issue.

PACIFIC GAS AND ELECTRIC COMPANY
GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
GTS-CARD-2023_DR_TURN_003-Q004Atch01

Base Case Forecast
(Cold Temperature Year)

Line No.		2023 Jan-23	2023 Feb-23	2023 Mar-23	2023 Apr-23	2023 May-23	2023 Jun-23	2023 Jul-23	2023 Aug-23	2023 Sep-23	2023 Oct-23	2023 Nov-23	2023 Dec-23
	CORE												
	RESIDENTIAL												
1	RESIDENTIAL IM BUNDLED	30,321	22,165	17,026	11,624	7,750	5,463	4,797	4,779	5,103	7,529	17,623	29,989
2	RESIDENTIAL IM TRANSPORT	2,867	2,102	1,614	1,158	802	585	518	517	549	782	1,690	2,823
3	RESIDENTIAL MM BUNDLED	1,818	1,430	1,261	1,155	921	713	656	640	658	836	1,272	1,773
4	RESIDENTIAL MM TRANSPORT	580	454	401	373	307	239	220	214	212	262	389	526
5	***TOTAL RESIDENTIAL***	**35,587**	**26,151**	**20,302**	**14,310**	**9,780**	**7,000**	**6,192**	**6,150**	**6,522**	**9,409**	**20,975**	**35,111**
6													
7	COMMERCIAL												
8	SMALL COMMERCIAL BUNDLED	7,126	5,588	4,934	4,591	3,783	2,951	2,716	2,636	2,616	3,222	4,782	6,461
9	SMALL COMMERCIAL TRANSPORT	4,073	3,195	2,792	2,184	1,814	1,501	1,458	1,468	1,520	1,907	2,748	4,083
10	LARGE COMMERCIAL BUNDLED	378	360	327	336	318	295	299	355	410	412	381	387
11	Distribution under 3 million	311	297	278	283	266	246	248	288	338	348	322	320
12	Transmission and Distribution over 3 million	69	65	50	53	52	49	52	67	72	65	61	69
13	LARGE COMMERCIAL TRANSPORT	264	255	236	229	216	210	199	214	238	233	240	253
14	Distribution under 3 million	218	210	201	194	181	175	165	174	196	196	203	209
15	Transmission and Distribution over 3 million	48	46	36	36	35	35	34	41	42	37	38	45
16	***TOTAL COMMERCIAL***	**11,841**	**9,399**	**8,289**	**7,341**	**6,132**	**4,957**	**4,672**	**4,673**	**4,784**	**5,774**	**8,151**	**11,184**
17													
18													
19	INTERDEPT												
20	GNR1	28	23	17	12	8	5	5	5	5	8	16	27
21	GNR2	-	-	-	-	-	-	-	-	-	-	-	-
22	***TOTAL INTERDEPARTMENTAL***	**28**	**23**	**17**	**12**	**8**	**5**	**5**	**5**	**5**	**8**	**16**	**27**
23													
24	NATURAL GAS VEHICLE												
25	NGV1--INTERDEPARTMENTAL	3	3	3	3	3	3	3	3	3	3	3	3
26	V1--NON-INTERDEPARTMENTAL BUNDLED	172	172	173	173	174	174	175	175	176	176	177	177
27	--NON-INTERDEPARTMENTAL TRANSPORT	38	38	38	39	39	39	39	39	39	39	39	39
28	NGV2--NON-INTERDEPARTMENTAL	12	12	12	12	12	12	12	12	12	12	12	12
29	***TOTAL NGV***	**224**	**225**	**225**	**226**	**227**	**227**	**228**	**229**	**229**	**230**	**231**	**231**
30													
31	***TOTAL CORE***	**47,680**	**35,798**	**28,834**	**21,889**	**16,147**	**12,190**	**11,097**	**11,057**	**11,540**	**15,421**	**29,373**	**46,553**
32													
33													
34	**NONCORE**												
35													
36	INDUSTRIAL												
37	INDUSTRIAL DISTRIBUTION	2,602	2,294	2,337	2,107	1,975	1,815	1,809	2,027	2,018	2,142	2,219	2,495
38	Distribution under 3 million	2,004	1,770	1,786	1,603	1,500	1,375	1,287	1,387	1,436	1,607	1,716	1,897
39	Distribution over 3 million	598	524	551	504	475	439	522	640	583	535	503	598
40	INDUSTRIAL TRANSMISSION	11,984	10,357	11,419	10,955	11,612	11,391	13,815	16,432	15,812	13,032	11,783	12,474
41	INDUSTRIAL BACKBONE	71	64	62	57	60	66	313	405	385	185	63	69
42	***TOTAL INDUSTRIAL***	**14,656**	**12,715**	**13,818**	**13,120**	**13,646**	**13,272**	**15,936**	**18,864**	**18,216**	**15,359**	**14,066**	**15,037**
43													
44													
45	ELECTRIC GENERATION												
46	Non-market-responsive D	964	872	941	942	973	953	1,002	999	981	973	933	940
47	Non-market-responsive T	3,389	3,721	3,106	2,940	3,302	3,828	4,068	4,828	4,604	4,417	3,331	3,692
48	Market-responsive, LT	2,365	2,006	1,452	1,231	1,140	1,156	1,726	1,929	2,033	2,031	2,169	2,700
49	Market-responsive, BB	11,249	7,648	3,249	1,941	1,861	3,780	8,570	10,873	8,511	8,349	8,488	12,644
50	***TOTAL EG***	**17,967**	**14,246**	**8,748**	**7,054**	**7,276**	**9,716**	**15,367**	**18,629**	**16,128**	**15,770**	**14,922**	**19,976**
51													
52	NGV4	109	110	110	110	111	111	111	112	112	112	112	113
53													
54	***TOTAL NONCORE***	**32,733**	**27,071**	**22,676**	**20,284**	**21,033**	**23,099**	**31,415**	**37,605**	**34,455**	**31,241**	**29,100**	**35,126**
55													
56	**WHOLESALE**												
57													
58	PALO ALTO	480	380	333	262	202	156	146	146	154	212	331	468
59	COALINGA	45	34	26	17	11	8	7	7	8	12	26	43
60	WEST COAST-CASTLE	10	8	7	5	4	3	3	3	3	4	6	9
61	WEST COAST-MATHER	20	14	11	7	5	3	3	3	3	5	11	18
62	ISLAND ENERGY	8	6	5	4	3	2	2	2	2	3	5	8
63	ALPINE	12	9	7	5	3	2	2	2	2	3	6	11
64	***TOTAL WHOLESALE***	**574**	**451**	**389**	**300**	**228**	**175**	**162**	**162**	**171**	**239**	**385**	**556**
65													
66	SHRINKAGE												
67	GAS DEPT USE (GDU)	313	327	341	418	422	356	260	303	331	336	328	347
68	LUAF	1,853	1,161	1,044	483	288	169	366	356	458	358	1,244	1,689
69	***TOTAL SHRINKAGE***	**2,165**	**1,488**	**1,385**	**901**	**710**	**525**	**626**	**660**	**789**	**694**	**1,572**	**2,036**
70													
71	***TOTAL DEMAND***	**83,152**	**64,808**	**53,284**	**43,375**	**38,118**	**35,989**	**43,300**	**49,483**	**46,956**	**47,594**	**60,430**	**84,270**
72													
73													
74	***TOTAL DEMAND NET OF SHRINKAGE***	**80,987**	**63,321**	**51,899**	**42,474**	**37,408**	**35,464**	**42,674**	**48,824**	**46,167**	**46,900**	**58,858**	**82,235**

PACIFIC GAS AND ELECTRIC COMPANY
GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
GTS-CARD-2023_DR_TURN_003-Q004Atch01

Base Case Forecast
(Cold Temperature Year)

Line No.		2024 Jan-24	2024 Feb-24	2024 Mar-24	2024 Apr-24	2024 May-24	2024 Jun-24	2024 Jul-24	2024 Aug-24	2024 Sep-24	2024 Oct-24	2024 Nov-24	2024 Dec-24
	CORE												
	RESIDENTIAL												
1	RESIDENTIAL IM BUNDLED	29,588	21,599	16,531	11,249	7,449	5,226	4,581	4,562	4,887	7,258	17,200	29,383
2	RESIDENTIAL IM TRANSPORT	2,798	2,048	1,567	1,121	771	559	495	494	525	754	1,650	2,766
3	RESIDENTIAL MM BUNDLED	1,774	1,393	1,225	1,118	885	682	626	611	630	806	1,242	1,737
4	RESIDENTIAL MM TRANSPORT	566	443	389	361	295	229	210	204	203	252	380	515
5	***TOTAL RESIDENTIAL***	**34,726**	**25,483**	**19,713**	**13,849**	**9,400**	**6,697**	**5,913**	**5,871**	**6,246**	**9,070**	**20,471**	**34,402**
6													
7	COMMERCIAL												
8	SMALL COMMERCIAL BUNDLED	7,181	5,631	4,958	4,603	3,771	2,931	2,695	2,614	2,600	3,217	4,826	6,538
9	SMALL COMMERCIAL TRANSPORT	4,124	3,234	2,826	2,206	1,827	1,503	1,449	1,459	1,511	1,896	2,735	4,067
10	LARGE COMMERCIAL BUNDLED	376	359	325	333	315	292	294	350	405	407	376	381
11	Distribution under 3 million	312	297	278	282	264	243	244	285	335	344	319	317
12	Transmission and Distribution over 3 million	69	65	50	53	51	49	51	67	72	64	60	68
13	LARGE COMMERCIAL TRANSPORT	263	254	235	228	214	208	196	212	236	229	237	248
14	Distribution under 3 million	218	210	201	193	180	173	163	172	194	194	201	207
15	Transmission and Distribution over 3 million	48	46	36	36	35	35	34	40	42	36	38	44
16	***TOTAL COMMERCIAL***	**11,945**	**9,478**	**8,344**	**7,371**	**6,127**	**4,932**	**4,634**	**4,635**	**4,752**	**5,749**	**8,174**	**11,235**
17													
18													
19	INTERDEPT												
20	GNR1	28	23	17	12	8	5	5	5	5	8	16	27
21	GNR2	-	-	-	-	-	-	-	-	-	-	-	-
22	***TOTAL INTERDEPARTMENTAL***	**28**	**23**	**17**	**12**	**8**	**5**	**5**	**5**	**5**	**8**	**16**	**27**
23													
24	NATURAL GAS VEHICLE												
25	NGV1--INTERDEPARTMENTAL	3	3	3	3	3	3	3	3	3	3	3	3
26	V1--NON-INTERDEPARTMENTAL BUNDLED	178	178	179	179	180	180	181	181	182	182	183	184
27	--NON-INTERDEPARTMENTAL TRANSPORT	40	40	40	40	40	40	40	40	40	41	41	41
28	NGV2--NON-INTERDEPARTMENTAL	12	12	12	12	12	12	12	12	12	12	12	12
29	***TOTAL NGV***	**232**	**233**	**233**	**234**	**235**	**235**	**236**	**237**	**237**	**238**	**239**	**239**
30													
31	***TOTAL CORE***	**46,931**	**35,217**	**28,307**	**21,466**	**15,770**	**11,870**	**10,788**	**10,747**	**11,240**	**15,065**	**28,900**	**45,903**
32													
33													
34	**NONCORE**												
35													
36	INDUSTRIAL												
37	INDUSTRIAL DISTRIBUTION	2,616	2,303	2,342	2,108	1,971	1,806	1,797	2,016	2,008	2,132	2,211	2,487
38	Distribution under 3 million	2,015	1,777	1,790	1,603	1,498	1,369	1,278	1,379	1,428	1,600	1,710	1,891
39	Distribution over 3 million	601	526	552	504	474	437	518	636	580	532	501	596
40	INDUSTRIAL TRANSMISSION	12,144	10,473	11,497	10,994	11,612	11,352	13,740	16,360	15,745	12,968	11,723	12,419
41	INDUSTRIAL BACKBONE	67	61	59	55	59	66	313	406	385	185	64	69
42	***TOTAL INDUSTRIAL***	**14,826**	**12,837**	**13,898**	**13,157**	**13,642**	**13,225**	**15,850**	**18,781**	**18,138**	**15,285**	**13,998**	**14,975**
43													
44													
45	ELECTRIC GENERATION												
46	Non-market-responsive D	964	903	941	942	973	953	1,002	999	981	973	933	940
47	Non-market-responsive T	3,389	3,854	3,106	2,940	3,302	3,828	4,068	4,828	4,604	4,417	3,331	3,692
48	Market-responsive, LT	2,090	1,719	1,401	1,257	1,157	1,121	1,570	1,682	2,087	1,722	2,052	2,813
49	Market-responsive, BB	10,513	6,094	3,179	1,931	1,805	3,705	7,903	10,037	8,194	7,627	9,729	14,408
50	***TOTAL EG***	**16,956**	**12,570**	**8,627**	**7,070**	**7,237**	**9,607**	**14,544**	**17,545**	**15,865**	**14,739**	**16,044**	**21,852**
51													
52	NGV4	113	113	114	114	114	115	115	115	116	116	116	116
53													
54	***TOTAL NONCORE***	**31,895**	**25,521**	**22,639**	**20,342**	**20,994**	**22,946**	**30,509**	**36,442**	**34,118**	**30,140**	**30,158**	**36,944**
55													
56	**WHOLESALE**												
57													
58	PALO ALTO	485	385	336	264	203	156	145	145	153	211	330	466
59	COALINGA	45	34	26	17	11	8	6	6	8	12	26	42
60	WEST COAST-CASTLE	10	8	7	6	4	3	3	3	3	4	6	9
61	WEST COAST-MATHER	20	14	11	7	5	3	3	3	3	5	11	18
62	ISLAND ENERGY	8	6	5	4	3	2	2	2	2	3	5	7
63	ALPINE	11	9	7	4	3	2	2	2	2	3	6	11
64	***TOTAL WHOLESALE***	**579**	**455**	**391**	**302**	**228**	**174**	**160**	**160**	**170**	**237**	**383**	**555**
65													
66	SHRINKAGE												
67	GAS DEPT USE (GDU)	311	327	339	415	419	353	258	301	329	334	325	344
68	LUAF	1,843	1,160	1,037	480	286	168	364	354	455	355	1,233	1,674
69	***TOTAL SHRINKAGE***	**2,154**	**1,487**	**1,376**	**895**	**705**	**521**	**622**	**655**	**784**	**688**	**1,558**	**2,018**
70													
71	***TOTAL DEMAND***	**81,558**	**62,679**	**52,713**	**43,004**	**37,697**	**35,511**	**42,078**	**48,005**	**46,312**	**46,130**	**61,000**	**85,419**
72													
73													
74	***TOTAL DEMAND NET OF SHRINKAGE***	**79,404**	**61,193**	**51,337**	**42,109**	**36,992**	**34,990**	**41,456**	**47,349**	**45,528**	**45,442**	**59,441**	**83,401**

PACIFIC GAS AND ELECTRIC COMPANY
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Base Case Forecast
(Cold Temperature Year)

Line No.		2025 Jan-25	2025 Feb-25	2025 Mar-25	2025 Apr-25	2025 May-25	2025 Jun-25	2025 Jul-25	2025 Aug-25	2025 Sep-25	2025 Oct-25	2025 Nov-25	2025 Dec-25
	CORE												
	RESIDENTIAL												
1	RESIDENTIAL IM BUNDLED	28,971	21,124	16,116	10,931	7,182	5,003	4,358	4,337	4,664	6,985	16,749	28,737
2	RESIDENTIAL IM TRANSPORT	2,740	2,003	1,528	1,089	743	535	471	470	501	725	1,606	2,705
3	RESIDENTIAL MM BUNDLED	1,737	1,363	1,194	1,086	854	653	596	581	602	776	1,209	1,699
4	RESIDENTIAL MM TRANSPORT	554	433	380	351	285	219	200	194	194	243	370	504
5	***TOTAL RESIDENTIAL***	**34,001**	**24,923**	**19,217**	**13,457**	**9,064**	**6,411**	**5,625**	**5,582**	**5,961**	**8,729**	**19,934**	**33,645**
6													
7	COMMERCIAL												
8	SMALL COMMERCIAL BUNDLED	7,159	5,623	4,940	4,583	3,731	2,882	2,636	2,556	2,547	3,166	4,794	6,509
9	SMALL COMMERCIAL TRANSPORT	4,086	3,212	2,804	2,190	1,813	1,490	1,436	1,446	1,498	1,877	2,710	4,032
10	LARGE COMMERCIAL BUNDLED	367	352	319	328	309	286	289	345	400	400	368	371
11	Distribution under 3 million	308	293	275	278	261	240	241	281	331	340	315	314
12	Transmission and Distribution over 3 million	68	64	49	52	51	48	50	66	71	64	59	67
13	LARGE COMMERCIAL TRANSPORT	257	249	230	224	211	204	193	208	232	226	232	242
14	Distribution under 3 million	216	207	198	190	178	171	160	170	192	192	198	205
15	Transmission and Distribution over 3 million	48	46	35	36	35	34	33	40	41	36	37	44
16	***TOTAL COMMERCIAL***	**11,869**	**9,436**	**8,293**	**7,325**	**6,065**	**4,863**	**4,554**	**4,555**	**4,677**	**5,669**	**8,104**	**11,154**
17													
18													
19	INTERDEPT												
20	GNR1	28	23	17	12	8	5	5	4	5	8	16	26
21	GNR2	-	-	-	-	-	-	-	-	-	-	-	-
22	***TOTAL INTERDEPARTMENTAL***	**28**	**23**	**17**	**12**	**8**	**5**	**5**	**4**	**5**	**8**	**16**	**26**
23													
24	NATURAL GAS VEHICLE												
25	NGV1--INTERDEPARTMENTAL	3	3	3	3	3	3	3	3	3	3	3	3
26	V1--NON-INTERDEPARTMENTAL BUNDLED	184	185	185	186	186	187	187	188	188	189	189	190
27	--NON-INTERDEPARTMENTAL TRANSPORT	41	41	41	41	41	42	42	42	42	42	42	42
28	NGV2--NON-INTERDEPARTMENTAL	12	12	12	12	13	13	13	13	13	13	13	13
29	***TOTAL NGV***	**240**	**241**	**241**	**242**	**243**	**243**	**244**	**245**	**245**	**246**	**247**	**247**
30													
31	***TOTAL CORE***	**46,138**	**34,622**	**27,769**	**21,036**	**15,379**	**11,522**	**10,427**	**10,386**	**10,889**	**14,651**	**28,300**	**45,074**
32													
33													
34	**NONCORE**												
35													
36	INDUSTRIAL												
37	INDUSTRIAL DISTRIBUTION	2,608	2,295	2,333	2,100	1,963	1,798	1,788	2,007	1,999	2,123	2,202	2,477
38	Distribution under 3 million	2,009	1,771	1,783	1,597	1,491	1,363	1,272	1,373	1,422	1,593	1,702	1,884
39	Distribution over 3 million	599	524	550	502	472	435	516	634	577	530	499	594
40	INDUSTRIAL TRANSMISSION	12,088	10,417	11,440	10,937	11,555	11,294	13,682	16,300	15,684	12,906	11,659	12,351
41	INDUSTRIAL BACKBONE	67	61	59	56	59	66	313	406	385	186	64	69
42	***TOTAL INDUSTRIAL***	**14,762**	**12,773**	**13,832**	**13,092**	**13,577**	**13,159**	**15,783**	**18,713**	**18,068**	**15,215**	**13,924**	**14,897**
43													
44													
45	ELECTRIC GENERATION												
46	Non-market-responsive D	964	872	941	942	973	953	1,002	999	981	973	933	940
47	Non-market-responsive T	3,389	3,721	3,106	2,940	3,302	3,828	4,068	4,828	4,604	4,417	3,331	3,692
48	Market-responsive, LT	1,923	1,567	1,374	1,145	1,111	1,113	1,459	1,497	1,931	1,659	2,071	3,042
49	Market-responsive, BB	10,937	6,900	3,210	1,924	1,817	3,719	7,627	9,521	8,771	8,484	12,507	15,896
50	***TOTAL EG***	**17,213**	**13,060**	**8,632**	**6,951**	**7,203**	**9,612**	**14,157**	**16,845**	**16,286**	**15,532**	**18,842**	**23,570**
51													
52	NGV4	117	117	117	118	118	118	119	119	119	120	120	120
53													
54	***TOTAL NONCORE***	**32,092**	**25,950**	**22,582**	**20,161**	**20,898**	**22,889**	**30,059**	**35,677**	**34,474**	**30,867**	**32,886**	**38,587**
55													
56	**WHOLESALE**												
57													
58	PALO ALTO	484	383	335	263	202	155	143	143	151	209	328	465
59	COALINGA	45	34	25	16	11	8	6	6	7	12	25	42
60	WEST COAST-CASTLE	10	8	7	5	4	3	3	3	3	4	6	9
61	WEST COAST-MATHER	20	14	11	7	5	3	3	3	3	5	11	18
62	ISLAND ENERGY	8	6	5	4	3	2	2	2	2	3	5	7
63	ALPINE	11	9	6	4	3	2	2	2	2	3	6	11
64	***TOTAL WHOLESALE***	**577**	**453**	**389**	**300**	**227**	**172**	**158**	**159**	**168**	**235**	**381**	**553**
65													
66	SHRINKAGE												
67	GAS DEPT USE (GDU)	308	322	336	411	415	350	256	299	327	331	322	341
68	LUAF	1,826	1,143	1,027	475	283	166	361	352	452	352	1,223	1,658
69	***TOTAL SHRINKAGE***	**2,134**	**1,465**	**1,362**	**886**	**698**	**516**	**618**	**651**	**778**	**683**	**1,545**	**1,999**
70													
71	***TOTAL DEMAND***	**80,941**	**62,491**	**52,102**	**42,383**	**37,202**	**35,099**	**41,262**	**46,872**	**46,309**	**46,436**	**63,113**	**86,213**
72													
73													
74	***TOTAL DEMAND NET OF SHRINKAGE***	**78,807**	**61,026**	**50,740**	**41,497**	**36,503**	**34,583**	**40,644**	**46,221**	**45,530**	**45,753**	**61,568**	**84,214**

PACIFIC GAS AND ELECTRIC COMPANY
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Base Case Forecast
(Cold Temperature Year)

Line No.		2026 Jan-26	2026 Feb-26	2026 Mar-26	2026 Apr-26	2026 May-26	2026 Jun-26	2026 Jul-26	2026 Aug-26	2026 Sep-26	2026 Oct-26	2026 Nov-26	2026 Dec-26
	CORE												
	RESIDENTIAL												
1	RESIDENTIAL IM BUNDLED	28,386	20,665	15,704	10,616	6,917	4,775	4,128	4,106	4,437	6,709	16,305	28,123
2	RESIDENTIAL IM TRANSPORT	2,684	1,959	1,489	1,058	716	511	446	445	477	697	1,564	2,647
3	RESIDENTIAL MM BUNDLED	1,702	1,333	1,163	1,055	822	624	564	550	572	745	1,177	1,663
4	RESIDENTIAL MM TRANSPORT	543	424	370	341	274	209	190	184	185	233	360	493
5	***TOTAL RESIDENTIAL***	**33,315**	**24,381**	**18,727**	**13,069**	**8,729**	**6,119**	**5,328**	**5,284**	**5,671**	**8,384**	**19,405**	**32,926**
6													
7	COMMERCIAL												
8	SMALL COMMERCIAL BUNDLED	7,141	5,615	4,918	4,561	3,691	2,832	2,574	2,494	2,492	3,115	4,761	6,482
9	SMALL COMMERCIAL TRANSPORT	4,047	3,187	2,780	2,174	1,800	1,477	1,423	1,432	1,485	1,858	2,682	3,996
10	LARGE COMMERCIAL BUNDLED	357	345	312	322	305	282	285	340	395	394	360	362
11	Distribution under 3 million	305	290	271	275	257	237	238	278	328	337	312	310
12	Transmission and Distribution over 3 million	67	64	48	52	50	47	49	65	70	63	59	67
13	LARGE COMMERCIAL TRANSPORT	250	244	226	220	207	201	190	206	229	222	227	236
14	Distribution under 3 million	214	205	196	188	175	169	158	168	190	190	196	202
15	Transmission and Distribution over 3 million	47	45	35	35	34	34	33	39	41	36	37	43
16	***TOTAL COMMERCIAL***	**11,795**	**9,390**	**8,237**	**7,277**	**6,003**	**4,791**	**4,471**	**4,472**	**4,601**	**5,589**	**8,031**	**11,076**
17													
18													
19	INTERDEPT												
20	GNR1	28	23	17	12	8	5	5	4	5	8	16	26
21	GNR2	-	-	-	-	-	-	-	-	-	-	-	-
22	***TOTAL INTERDEPARTMENTAL***	**28**	**23**	**17**	**12**	**8**	**5**	**5**	**4**	**5**	**8**	**16**	**26**
23													
24	NATURAL GAS VEHICLE												
25	NGV1--INTERDEPARTMENTAL	3	3	3	3	3	3	3	3	3	3	3	3
26	V1--NON-INTERDEPARTMENTAL BUNDLED	190	191	191	192	192	193	193	194	194	195	195	196
27	--NON-INTERDEPARTMENTAL TRANSPORT	42	42	43	43	43	43	43	43	43	43	43	44
28	NGV2--NON-INTERDEPARTMENTAL	13	13	13	13	13	13	13	13	13	13	13	13
29	***TOTAL NGV***	**248**	**249**	**249**	**250**	**251**	**251**	**252**	**253**	**253**	**254**	**255**	**255**
30													
31	***TOTAL CORE***	**45,385**	**34,043**	**27,229**	**20,608**	**14,991**	**11,167**	**10,056**	**10,014**	**10,530**	**14,236**	**27,707**	**44,284**
32													
33													
34	**NONCORE**												
35													
36	INDUSTRIAL												
37	INDUSTRIAL DISTRIBUTION	2,598	2,286	2,323	2,089	1,953	1,788	1,778	1,996	1,989	2,113	2,191	2,467
38	Distribution under 3 million	2,001	1,764	1,776	1,590	1,483	1,355	1,265	1,366	1,415	1,585	1,694	1,875
39	Distribution over 3 million	597	522	548	500	469	433	513	630	574	527	497	591
40	INDUSTRIAL TRANSMISSION	12,018	10,344	11,364	10,859	11,475	11,214	13,601	16,219	15,603	12,827	11,580	12,274
41	INDUSTRIAL BACKBONE	67	61	59	55	59	66	313	406	385	185	63	69
42	***TOTAL INDUSTRIAL***	**14,682**	**12,691**	**13,746**	**13,003**	**13,487**	**13,068**	**15,692**	**18,622**	**17,978**	**15,125**	**13,835**	**14,809**
43													
44													
45	ELECTRIC GENERATION												
46	Non-market-responsive D	964	872	941	942	973	953	1,002	999	981	973	933	940
47	Non-market-responsive T	3,389	3,721	3,106	2,940	3,302	3,828	4,068	4,828	4,604	4,417	3,331	3,692
48	Market-responsive, LT	2,077	1,688	1,380	1,201	1,105	1,102	1,556	1,653	1,962	1,603	2,001	2,849
49	Market-responsive, BB	13,269	9,211	3,871	1,930	1,873	3,783	8,410	10,143	10,557	10,803	13,162	16,311
50	***TOTAL EG***	**19,699**	**15,491**	**9,299**	**7,013**	**7,253**	**9,666**	**15,037**	**17,623**	**18,103**	**17,796**	**19,427**	**23,792**
51													
52	NGV4	120	121	121	121	122	122	122	123	123	123	124	124
53													
54	***TOTAL NONCORE***	**34,502**	**28,303**	**23,166**	**20,138**	**20,861**	**22,856**	**30,851**	**36,368**	**36,204**	**33,044**	**33,386**	**38,725**
55													
56	**WHOLESALE**												
57													
58	PALO ALTO	482	382	333	261	200	153	142	142	150	208	327	463
59	COALINGA	45	34	25	16	11	7	6	6	7	12	25	42
60	WEST COAST-CASTLE	10	8	7	5	4	3	3	3	3	4	6	9
61	WEST COAST-MATHER	19	14	11	7	4	3	2	3	3	5	10	18
62	ISLAND ENERGY	8	6	5	4	3	2	2	2	2	3	5	7
63	ALPINE	11	8	6	4	3	2	2	2	2	3	6	11
64	***TOTAL WHOLESALE***	**575**	**452**	**388**	**298**	**225**	**171**	**157**	**157**	**166**	**233**	**380**	**551**
65													
66	SHRINKAGE												
67	GAS DEPT USE (GDU)	306	319	332	407	411	347	254	297	324	328	319	339
68	LUAF	1,811	1,133	1,017	470	281	165	358	350	448	349	1,211	1,647
69	***TOTAL SHRINKAGE***	**2,116**	**1,452**	**1,349**	**878**	**692**	**512**	**613**	**647**	**773**	**678**	**1,530**	**1,986**
70													
71	***TOTAL DEMAND***	**82,579**	**64,250**	**52,132**	**41,922**	**36,769**	**34,706**	**41,676**	**47,185**	**47,673**	**48,191**	**63,002**	**85,546**
72													
73													
74	***TOTAL DEMAND NET OF SHRINKAGE***	**80,463**	**62,798**	**50,783**	**41,045**	**36,077**	**34,194**	**41,063**	**46,538**	**46,900**	**47,513**	**61,472**	**83,560**

Base Case Forecast
(Cold Temperature Year)

Line No.		CYPM December 2023	CYPM December 2024	CYPM December 2025	CYPM December 2026
	CORE				
	RESIDENTIAL				
1	RESIDENTIAL IM BUNDLED	299,890	293,832	287,375	281,228
2	RESIDENTIAL IM TRANSPORT	28,226	27,655	27,047	26,469
3	RESIDENTIAL MM BUNDLED	17,733	17,375	16,992	16,629
4	RESIDENTIAL MM TRANSPORT	5,259	5,153	5,040	4,932
5	***TOTAL RESIDENTIAL***	351,107	344,015	336,454	329,257
6					
7	COMMERCIAL				
8	SMALL COMMERCIAL BUNDLED	64,614	65,385	65,087	64,816
9	SMALL COMMERCIAL TRANSPORT	40,827	40,673	40,320	39,961
10	LARGE COMMERCIAL BUNDLED	3,873	3,811	3,715	3,622
11	Distribution under 3 million	3,204	3,173	3,137	3,104
12	Transmission and Distribution over 3 million	687	680	673	666
13	LARGE COMMERCIAL TRANSPORT	2,525	2,485	2,422	2,362
14	Distribution under 3 million	2,089	2,069	2,045	2,024
15	Transmission and Distribution over 3 million	448	444	439	434
16	***TOTAL COMMERCIAL***	111,839	112,354	111,544	110,761
17					
18					
19	INTERDEPT				
20	GNR1	266	265	264	264
21	GNR2	0	0	0	0
22	***TOTAL INTERDEPARTMENTAL***	266	265	264	264
23					
24	NATURAL GAS VEHICLE				
25	NGV1--INTERDEPARTMENTAL	27	27	27	27
26	V1--NON-INTERDEPARTMENTAL BUNDLED	1,773	1,835	1,897	1,960
27	--NON-INTERDEPARTMENTAL TRANSPORT	394	408	422	436
28	NGV2--NON-INTERDEPARTMENTAL	119	123	128	132
29	***TOTAL NGV***	2,313	2,394	2,474	2,555
30					
31	***TOTAL CORE***	465,525	459,028	450,737	442,836
32					
33					
34	**NONCORE**				
35					
36	INDUSTRIAL				
37	INDUSTRIAL DISTRIBUTION	24,946	24,870	24,773	24,668
38	Distribution under 3 million	18,966	18,908	18,835	18,755
39	Distribution over 3 million	5,980	5,961	5,938	5,913
40	INDUSTRIAL TRANSMISSION	124,737	124,192	123,512	122,736
41	INDUSTRIAL BACKBONE	687	688	689	686
42	***TOTAL INDUSTRIAL***	150,370	149,750	148,974	148,089
43					
44					
45	ELECTRIC GENERATION				
46	Non-market-responsive D	9,400	9,400	9,400	9,400
47	Non-market-responsive T	36,918	36,918	36,918	36,918
48	Market-responsive, LT	26,999	28,127	30,419	28,490
49	Market-responsive, BB	126,442	144,078	158,960	163,115
50	***TOTAL EG***	199,759	218,522	235,697	237,922
51					
52	NGV4	1,128	1,165	1,202	1,239
53					
54	***TOTAL NONCORE***	351,257	369,437	385,873	387,250
55					
56	**WHOLESALE**				
57					
58	PALO ALTO	4,676	4,661	4,647	4,632
59	COALINGA	426	425	423	422
60	WEST COAST-CASTLE	94	94	93	93
61	WEST COAST-MATHER	181	180	180	179
62	ISLAND ENERGY	75	75	75	74
63	ALPINE	112	112	111	111
64	***TOTAL WHOLESALE***	5,564	5,546	5,529	5,512
65					
66	SHRINKAGE				
67	GAS DEPT USE (GDU)	3,472	3,441	3,410	3,387
68	LUAF	16,886	16,737	16,583	16,470
69	***TOTAL SHRINKAGE***	20,358	20,178	19,993	19,857
70					
71	***TOTAL DEMAND***	842,704	854,190	862,132	855,455
72					
73					
74	***TOTAL DEMAND NET OF SHRINKAGE***	822,346	834,011	842,138	835,598

		CYPM December 2023	CYPM December 2024	CYPM December 2025	CYPM December 2026	Contract and G-10 Adjustments, BBT 2023	2024	2025	2026	Adjusted CYPM Volumes for Allocation 2023	2024	2025	2026
Core Retail													
Residential	Line 5	351,107	344,015	336,454	329,257	-340	-333	-326	-319	350,768	343,683	336,128	328,939
Small Comm	Line 8 + Line 9 + Line 20	105,707	106,323	105,672	105,040					105,707	106,323	105,672	105,040
Large Comm	Line 10 + Line 13	6,398	6,296	6,137	5,984					6,398	6,296	6,137	5,984
Core NGV	Line 29	2,313	2,394	2,474	2,555					2,313	2,394	2,474	2,555
Total Core Retail	Line 31	465,525	459,028	450,737	442,836	-340	-333	-326	-319	465,186	458,695	450,411	442,518
Noncore Retail													
IND-D	Line 37	24,946	24,870	24,773	24,668					24,946	24,870	24,773	24,668
IND-T	Line 40	124,737	124,192	123,512	122,736	-891	-833	-762	-711	123,846	123,359	122,750	122,025
IND-BBT	Line 41	687	688	689	686	-687	-688	-689	-686	0	0	0	0
G-EG D & T	Line 46 + Line 47 + Line 48	73,317	74,445	76,737	74,808	-70	-70	-70	-70	73,247	74,375	76,667	74,738
G-EG BB T	Line 49	126,442	144,078	158,960	163,115	-126,442	-144,078	-158,960	-163,115	0	0	0	0
Noncore NGV	Line 52	1,128	1,165	1,202	1,239					1,128	1,165	1,202	1,239
Wholesale													
Palo Alto	Line 58	4,676	4,661	4,647	4,632					4,676	4,661	4,647	4,632
Coalinga	Line 59	426	425	423	422					426	425	423	422
West Coast-Castle	Line 60	94	94	93	93					94	94	93	93
West Coast-Mather	Line 61	181	180	180	179					181	180	180	179
Island Energy	Line 62	75	75	75	74					75	75	75	74
Alpine	Line 63	112	112	111	111					112	112	111	111
Totals Paying Noncore Rate	Line 54 + Line 64	356,821	374,983	391,402	392,762	-128,090	-145,669	-160,480	-164,581	228,731	229,315	230,922	228,181
System Totals	Line 74	822,346	834,011	842,138	835,598	-128,429	-146,002	-160,806	-164,900	693,917	688,010	681,333	670,699

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2B

REBUTTAL TESTIMONY OF

ANDREW S. KLINGLER ON

NON-GENERATION GAS DEMAND AND

THROUGHPUT FORECAST

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2B
REBUTTAL TESTIMONY OF
ANDREW S. KLINGLER ON
NON-GENERATION GAS DEMAND AND
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2B
REBUTTAL TESTIMONY OF
ANDREW S. KLINGLER ON
NON-GENERATION GAS DEMAND AND
THROUGHPUT FORECAST

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Andrew S. Klingler, Senior Manager of Rate Architecture and Load Forecasting.

Q 2 Did any party offer written testimony relating to Chapter 2B Non-Generation Demand and Throughput Forecast[1] of Pacific Gas and Electric Company's (PG&E) Prepared Testimony?

A 2 No. Parties do not offer written testimony regarding PG&E's Chapter B Non-Generation Demand and Throughput Forecast.

Q 3 Does PG&E have any changes or corrections to its Chapter 2B proposals?

A 3 No. PG&E does not have changes or corrections to its Chapter 2B proposals.

B. Conclusion

Q 4 What is PG&E's recommendation for Non-Generation Demand and Throughput Forecast?

A 4 PG&E recommends its forecasts for gas demand and throughput for core, noncore and wholesale be adopted as proposed in its Prepared Testimony.[2]

Q 5 Does this conclude your rebuttal testimony?

A 5 Yes, it does.

---

1 PG&E Errata Testimony (Aug. 18, 2022), Ch. 2B.

2 Specifically, PG&E Errata Testimony (Aug. 18, 2022), Tables 2B-1 and 2B-2 should be found reasonable and adopted.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REBUTTAL TESTIMONY OF

CARL ORR ON

BACKBONE RATE INPUTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
REBUTTAL TESTIMONY OF
CARL ORR ON
BACKBONE RATE INPUTS

A. Introduction

Q 1 Please state your name, title, and the purpose of this rebuttal testimony.

A 1 My name is Carl Orr. I am a Principal Program Manager in Pacific Gas and Electric Company's (PG&E) Gas Engineering organization. My testimony responds to the joint testimony of Citadel Energy Marketing LLC and Tourmaline Oil Marketing Corp (C&T),[1] and the testimony of the Small Business Utility Advocates (SBUA).[2]

Q 2 Do these parties criticize PG&E's showing in Chapter 3, Backbone Rate Inputs?

A 2 Yes, both parties criticize the use of the system average load factor to set backbone rates. Both parties also criticize PG&E's proposed rate differential between the Baja and Redwood backbone transportation paths. In Section B of this testimony, PG&E summarizes these parties' positions. In Sections C and D, PG&E explains its disagreement with their positions.

Q 3 Are there any proposals in Chapter 3 that the parties do not dispute or do not address?

A 3 Yes, there are three remaining proposals in Chapter 3 that the parties do not dispute in written testimony.

Q 4 Does PG&E have any changes or clarifications to its Chapter 3 proposals?

A 4 No, PG&E does not have any changes or clarifications to its Chapter 3 proposals.

B. Summary of Parties' Positions

Q 5 What are the proposals in Chapter 3 that the parties do not dispute?

A 5 No party disputes PG&E's proposals for the following backbone rate inputs:

- The forecast of off-system revenues and throughput;

---

1 CT-0001.

2 SBUA Direct Testimony, Sections 7 and 8.

- The forecast of backbone firm contracts; and
- The forecast of California production volumes (conventional production and renewable natural gas production) transported on the backbone system.

Q 6 Briefly, what are the parties' positions with respect to the use of the system average load factor to set backbone rates, and what is PG&E's response?

A 6 C&T claims that the use of the system average load factor causes backbone customers on the Redwood path to subsidize backbone customers on the Baja path. C&T does not recommend changing the system average load factor methodology, but believes that the use of path-specific load factors rather than the system average load factor would remedy the alleged subsidy.[3]

SBUA states that backbone rates should more closely reflect actual market conditions on each backbone path. SBUA does not recommend an alternative to the system average load factor, but recommends that the California Public Utilities Commission (Commission) revisit the system average load factor methodology.[4]

PG&E's Response

C&T's and SBUA's criticisms of the system average backbone load factor are unfounded and contrary to long-standing Commission policy. The system average load factor methodology neither causes inter-path subsidies nor fails to reflect market conditions on each path. Rather, it provides for an equitable allocation of the costs of slack capacity[5] and avoids various other pitfalls associated with path-specific load factors. See Section C below for further discussion.

Q 7 Briefly, what are the parties' positions with respect to the Baja-Redwood backbone rate differential, and what is PG&E's response?

A 7 C&T opposes PG&E's proposal to set the Baja-Redwood rate differential at 50 percent of the natural rate differential.[6] Instead, C&T favors setting the

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3 CT-0001, p. 5, line 16 to p. 6, line 2, p. 15, line 18 to p. 16, line 13.

4 SBUA Direct Testimony, p. 10.

5 The term "slack capacity" is explained below in Section C.

6 The term "natural rate differential" is explained below in Section D.

rate differential at 100 percent of the natural rate differential.[7] C&T appears to agree with PG&E that backbone rates should be set in accordance with cost causation principles, but disagrees that PG&E's proposed 50 percent rate differential achieves this objective.[8]

SBUA recommends continuation of the current (2022) Baja-Redwood rate differential of $0.18 per dekatherm (Dth) during the Cost Allocation and Rate Design (CARD) case period (2023-2026).[9] That rate differential was set by stipulation in PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case.[10]

<u>PG&E's Response</u>

C&T's and SBUA's criticisms of PG&E's proposal to set the Baja-Redwood rate differential at 50 percent of the natural differential, and their alternative proposals to set the rate differential at 100 percent of the natural differential or at the level currently in effect for 2022, are inconsistent with cost causation principles and unsupported by the evidence. In addition, C&T's testimony reveals numerous misunderstandings of PG&E's tariffs, commercial practices, and system operations. See Section D below for further discussion.

C. The Commission Should Continue to Employ the System Average Load Factor to Set PG&E's Backbone Rates, and Should Reject Arguments That the System Average Load Factor Causes Inter-Path Subsidies

Q 8 Briefly, what is PG&E's proposal regarding the load factor methodology used to set backbone rates?

A 8 Consistent with the Commission's practice during the entire 25 years that PG&E's backbone transmission services have been unbundled, PG&E proposes to set backbone rates based on the system average load factor rather than path-specific load factors.

---

7 CT-0001, p. i, p. 2, line 22 to p.3, line 3 and lines 14-22, and p. 15, line 18 to p. 16, line 13.

8 *Id*. at p. i, p. 3, lines 12-22, and p. 16, lines 8-10.

9 SBUA Direct Testimony, p. 12.

10 Decision (D.) 19-09-025, pp. 254-256, p. 320, Conclusion of Law (COL) 128, and p. 334 Ordering Paragraph (OP) 83.

Q 9 Do any parties criticize PG&E's use of the system average load factor to set backbone rates?

A 9 Yes, as already mentioned, C&T claims that use of the system average load factor causes Redwood path customers to subsidize Baja path customers,[11] and SBUA asserts that backbone rates should more closely reflect actual market conditions on each backbone path.[12] Neither party recommends an alternative to the system average load factor methodology, but C&T believes that use of path-specific load factors rather than the system average load factor would eliminate the alleged subsidy, while SBUA asks the Commission to revisit the system average load factor methodology.

Q 10 Do you agree with C&T's and SBUA's criticisms of the system average load factor?

A 10 No. These criticisms are unfounded and contrary to long-standing Commission practice. As demonstrated in this section, the system average load factor does not cause subsidies between backbone paths, nor does it fail to reflect market conditions on each path. To the contrary, the system average load factor provides for an equitable allocation of the costs of slack capacity, and it avoids other pitfalls inherent in path-specific load factors.

Q 11 Let's be clear on terminology. What is the system average load factor?

A 11 The system average load factor represents average daily throughput on PG&E's backbone system over the course of a year, expressed as a percentage of daily backbone capacity, plus various adjustments:

$$\text{System Average Load Factor} = \frac{\text{Total Backbone Demand} + \text{Adjustments}}{\text{Total Backbone Capacity} + \text{Adjustments}}$$

The system average load factors that PG&E proposed in this case range from 61.55 percent to 66.10 percent. These load factors are fully discussed in PG&E's prepared testimony.[13]

---

[11] See footnote (fn) 3.

[12] See fn 4.

[13] PG&E Errata Testimony (Aug. 18, 2022), pp. 3-1, line 11 to pp. 3-5, line 21 (conceptual discussion) and pp. 3-5, line 24 to pp. 3-17, line 25 (computational details).

Q 12 How is the system average load factor used in the backbone rate design?

A 12 PG&E uses the system average load factor to calculate rates for each backbone path. In simple terms, the backbone rate for a given path is calculated by dividing the costs allocated to the path by the product of the path capacity multiplied by the system average load factor:

$$\text{Path Rate} = \frac{\text{Allocated Path Costs (\$ '000)}}{\text{Path Capacity (MDth/d)} \times \text{System Average Load Factor (\%)} \times \text{365 d}}$$

In effect, this methodology allocates systemwide gas demand to the various backbone paths in proportion to each path's capacity—for rate design purposes. The backbone rate design is more fully discussed in PG&E's prepared testimony.[14]

Q 13 How long has the system average load factor been used in PG&E's backbone rate design?

A 13 The system average load factor has been used continuously in PG&E's backbone rate design since PG&E's backbone rates were first unbundled in March 1998.

Q 14 How would path-specific load factors change PG&E's backbone rates?

A 14 The table below illustrates the approximate impact of path-specific load factors on PG&E's backbone rates in 2023. For simplicity, the table combines core and noncore Redwood rates.

---

14 *Id*. at pp. 3-3, line 9 to pp. 3-4, line 14, and pp. 6-7, line 16 to pp. 6-11, line 11.

TABLE 3-1
2023 BACKBONE RATES
SYSTEM AVERAGE VERSUS PATH SPECIFIC LOAD FACTORS

Line No.		Redwood (a)	Baja	Silverado	G-XF
1	**Cost and Capacity**				
2	Allocated Costs ($ million)	$247.7	$140.3	$6.2	$5.6
3	Capacity (MDth/d) (b)	1,978	920	69	86
4	**System Average Load Factor** (c)				
5	Load Factor	65.3%	65.3%	65.3%	100.0%
6	Rate ($/Dth) (d)	**$0.525**	**$0.640**	**$0.376**	**$0.177**
7	**Path-Specific Load Factors**				
8	Load Factor	80.5%	39.1%	65.3%	100.0%
9	Rate ($/Dth) (d)	**$0.426**	**$1.068**	**$0.376**	**$0.177**

Notes: (a) For simplicity, core Redwood and noncore Redwood rates are combined.
(b) Capacities exclude Sacramento Municipal Utility District (SMUD) equity capacity.
(c) System average load factor rates assume a "natural" Baja-Redwood rate differential.
(d) Rates are Schedule G-AFT rates expressed at 100% contract usage.

The path-specific load factors of approximately 81 percent for the Redwood path and 39 percent for the Baja path are based on the same gas demand forecast, backbone firm contracts forecast, backbone throughput analysis, and other factors underlying PG&E's proposed backbone load factor and rates.[15] These load factors do not reflect operational throughput levels because of various load factor adjustments necessary to ensure proper cost recovery.[16] The operational load factors are approximately 86 percent for the Redwood path and 27 percent for the Baja path.

The impact of replacing the system average load factor with path-specific load factors is significant. The 2023 Redwood rate decreases 19 percent, from about $0.53 to $0.43 per Dth, and the Baja rate increases 67 percent, from about $0.64 to $1.07 per Dth. The Silverado and Schedule G-XF rates are unaffected.

[15] *Id*. at Chs. 2A and 2B (gas demand forecast); Ch. 3, Section D.3 (backbone firm contracts forecast); and Ch. 3, Workpaper 3 (backbone throughput analysis).

[16] *Id*. at Ch 3, Section B.4 (backbone load factor adjustments).

Q 15 How would path-specific load factors affect PG&E's backbone rates in subsequent years of the CARD case period?

A 15 The impact of using path-specific load factors instead of the system average load factor is even more pronounced in subsequent years. By 2026, path-specific load factors would cause the Redwood rate to decrease 31 percent, from about $0.74 to $0.51 per Dth, and the Baja rate to increase 173 percent, from about $1.01 to $2.75 per Dth.

Q 16 Do the rates described above support C&T's claim that the use of the system average load factor causes Redwood path customers to subsidize Baja path customers?

A 16 No. As explained in PG&E's prepared testimony,[17] and further explained below, path-specific load factors result in a highly inequitable allocation of the costs of slack capacity on PG&E's backbone system. Contrary to C&T's assertions, the system average load factor methodology prevents rather than causes inter-path subsidies.

Q 17 Let's explore this matter further. What causes the substantial differences in backbone rates between the system average load factor method and the path-specific load factor method?

A 17 If PG&E's backbone system ran at 100 percent of capacity every day, there would be no difference in backbone rates between the two methods. However, PG&E's backbone system has a considerable amount of slack capacity, that is, capacity that is excess to average daily demand in an average year. Such capacity is necessary to serve peak demands and provides other benefits described below. The system average load factor method and the path-specific load factor method essentially allocate the costs of slack capacity differently. The former allocates slack capacity costs proportionally to all load on all backbone paths, while the latter allocates these costs primarily to the load on the marginal or out-of-favor path(s).

Q 18 How much slack capacity exists on PG&E's backbone system?

A 18 In simple terms and very round numbers, PG&E's backbone system has about 3 billion cubic feet (Bcf) per day of delivery capacity, consisting of about 2 Bcf per day on the Redwood path and about 1 Bcf per day on the

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[17] *Id*. at pp. 3-5, lines 1-14.

Baja path. Together, these paths serve average daily demand of about 2 Bcf per day. Thus, on an average day, PG&E has about 1 Bcf per day of slack capacity, representing about one-third of its backbone delivery capability—again, in round numbers.

Q 19 Does slack backbone capacity provide any benefits to PG&E's customers?

A 19 Yes, slack backbone capacity provides several benefits:

- It helps ensure supply availability during periods of above average gas demand, such as cold winters or dry hydroelectric years.
- It helps ensure supply availability during planned or unplanned facility outages or supply disruptions.
- It moderates price increases that may otherwise occur during the periods of increased demand or decreased supply described above.
- It facilitates competition between the various gas production basins connected to California via different backbone paths, further moderating gas prices. In the past 25 years, there have been several market shifts on PG&E's system, from a preference for gas produced in the U.S. Southwest (delivered on PG&E's Baja path) to a preference for gas produced in Canada (delivered on PG&E's Redwood path) and vice versa. The slack capacity on PG&E's backbone system gives marketers and end-users the flexibility to shift their loads toward the lowest cost supply source.[18]
- It increases customers' flexibility regarding the timing of injections to and withdrawals from underground gas storage facilities. Gas is typically purchased for storage injection when gas prices are low and withdrawn from storage in the future when gas prices are high. Absent the existence of slack capacity on PG&E's backbone system, storage customers would be constrained in their ability to time their storage injections and withdrawals.

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18 As explained below in Section D, the Baja and Redwood paths have distinct receipt points, but share common delivery points. Thus, no customer is confined to one path or the other based on the location of the customer's premises.

Q 20 Does the Commission require PG&E to hold slack backbone capacity?

A 20 Yes. The Commission addressed this issue in the "Gas Capacity Order Instituting Rulemaking (OIR)."[19] In its Phase 2 decision in that case, the Commission noted that "[r]eserve margins on backbone pipelines have routinely been in the 40% to 50% level."[20] The Commission also stated that it was "comfortable with the backbone transmission capacit[ies] of the [California gas] utilities."[21] Additionally, the Commission adopted PG&E's and Southern California Gas Company's (SoCalGas) proposed minimum slack capacity ranges.[22] For PG&E, the minimum slack capacity is described as follows: PG&E shall "maintain backbone transmission capacity sufficient to result in an 80%-90% utilization factor under cold temperature and dry hydroelectric conditions that have a one-in-ten-year likelihood of occurrence."[23] Finally, the Commission ordered PG&E and SoCalGas to file biennial advice letters demonstrating that their systems have adequate backbone capacity, including slack capacity margins consistent with the criteria adopted in the case.[24]

Q 21 How has PG&E's backbone capacity changed since the Commission issued its Phase 2 decision in the Gas Capacity OIR in 2006?

A 21 PG&E's backbone capacity has declined moderately since 2006. During the CARD case period, PG&E projects that its overall backbone capacity will be approximately 8 percent lower than in 2006. Baja capacity will be 13 percent lower, Redwood capacity will be 1 percent lower, and Silverado throughput will be 67 percent lower.

Q 22 Please provide PG&E's 1-in-10-year cold and dry demand forecast for the CARD case period and comment on the adequacy of PG&E's backbone capacity based on the criteria the Commission adopted in the Gas Capacity OIR proceeding.

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19 *Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California*, R.04-01-025 (Jan. 22, 2004).

20 D.06-09-039, p. 171, Finding of Fact (FOF) 8.

21 *Id.*, p. 172, FOF 12.

22 *Id.*, p. 26, p. 172, FOF 13, and p. 179, Conclusion of Law 1.

23 *Id.*, p. 9.

24 *Id.*, p. 184, Ordering Paragraph 3.

A 22 The table below shows the following for 2023-2026: PG&E's 1-in-10-year cold and dry demand forecast; PG&E's backbone capacity; and the resulting backbone utilization factor. The utilization factor is lower than 80-90 percent, indicating that PG&E has satisfied the minimum slack capacity requirement. The table also shows the required minimum backbone capacities necessary to satisfy the 80-90 percent criteria. By 2026, PG&E's backbone capacity (2,907 million cubic feet (MMcf) per day) will come within 116 MMcf per day of the upper end of the required minimum backbone capacity range (2,791 MMcf per day).

TABLE 3-2
2023-2026 BACKBONE SLACK CAPACITY MARGINS
(MMCF PER DAY)

Line No.		2023	2024	2025	2026
1	**1-in-10-Year Cold and Dry**				
2	**Demand** (a)	2,205	2,200	2,197	2,233
3	**Backbone Capacity**				
4	Baja (b)	935	935	935	935
5	Redwood (b)	2,060	2,060	1,963	1,915
6	Silverado (c)	45	54	55	57
7	Total	3,040	3,049	2,953	2,907
8	**Utilization Factor**	73%	72%	74%	77%
9	**Required Minimum Backbone**				
10	**Capacity**				
11	90% Utilization Criteria	2,450	2,444	2,441	2,481
12	80% Utilization Criteria	2,756	2,750	2,746	2,791

Notes: (a) 1-in-10-year cold and dry demand forecast obtained from PG&E Advice 4625-G, July 1, 2022. Grossed up to backbone receipt point. Includes throughput on SMUD equity capacity.

(b) Baja and Redwood backbone capacities obtained from PG&E's 2023 General Rate Case and 2023 CARD Case prepared testimony, Chapter 3, Workpaper 5A. Expressed as receipt point capacities. Includes SMUD equity capacity.

(c) Silverado throughput obtained from PG&E's 2023 CARD Case prepared tesimony, Chapter 3.

Q 23 What are your conclusions about PG&E's slack backbone capacity?

A 23 As noted above, PG&E's slack backbone capacity provides substantial supply reliability, supply flexibility, storage injection and withdrawal flexibility, and price moderation benefits to PG&E's customers. Additionally, in the

Gas Capacity OIR, the Commission adopted rules requiring PG&E to hold substantial amounts of slack backbone capacity, and PG&E has complied with these rules. Given these facts, particularly the broad benefits that slack backbone capacity affords to all customers, the costs of such capacity should continue to be borne by all customers.

Q 24 Turning again to PG&E's backbone rate design, you mentioned in response to an earlier question (Question 17) that the system average load factor method allocates slack capacity costs proportionally to all load on all backbone paths, while the path-specific load factor method allocates these costs primarily to the load on the marginal or out-of-favor path(s). Please explain.

A 24 Consider the unit costs of capacity on the Redwood and Baja backbone paths, which can be developed by dividing the allocated revenue requirement for each path by the capacity of the path. For 2023, the unit capacity costs for the Redwood and Baja paths are approximately $0.34 and $0.42 per Dth, respectively. If these were the actual rates on the two backbone paths, they would by definition exclude the costs of slack capacity. Stated another way, they are the rates that would result from 100 percent load factor rate design.

One can compare these unit cost rates to the actual rates obtained under the system average load factor method and the path-specific load factor method to determine the slack capacity costs embedded in rates under each method. This comparison is presented in the table below for 2023 backbone rates. The important thing to note is the system average load factor methodology produces a proportional allocation of slack capacity costs to the Redwood and Baja paths, while the path-specific load factor methodology produces an allocation that is heavily skewed toward the marginal (currently Baja) path.

TABLE 3-3
2023 BACKBONE RATES
SLACK CAPACITY COSTS EMBEDDED IN BACKBONE RATES

Line No.		Redwood	Baja
1	**Cost and Capacity** (a)		
2	Allocated Costs ($ million)	$247.7	$140.3
3	Capacity (MDth/d)	1,978	920
4	**Unit Capacity Cost** ($/Dth)	**$0.343**	**$0.418**
5	**System Average Load Factor**		
6	Total Rate ($/Dth) (a)	**$0.525**	**$0.640**
7	Embedded Slack Capacity Cost ($/Dth)	$0.182	$0.222
8	**Path-Specific Load Factors**		
9	Total Rate ($/Dth) (a)	**$0.426**	**$1.068**
10	Embedded Slack Capacity Cost ($/Dth)	$0.083	$0.650

Notes: (a) Cost, capacity, and rates are from Table 3-1.

Q 25 Please demonstrate how the costs of slack capacity are proportionally allocated to the Redwood and Baja paths under the system average load factor rate design.

A 25 As the above table shows, the system average load factor produces a Redwood rate of $0.525 per Dth, which is 53 percent higher than the Redwood unit capacity cost of $0.343 per Dth. Similarly, the system average load factor produces a Baja rate of $0.640 per Dth, which is also 53 percent higher than the Baja unit capacity cost of $0.418. The inclusion of slack capacity costs in these rates increases the rates by the same percentage over the unit capacity cost. In contrast, path-specific load factors produce a Redwood rate that is only 24 percent higher than the unit capacity cost and a Baja rate that is 155 percent higher than the unit capacity cost.

Q 26 Does this disparity in the allocation of slack capacity costs continue into subsequent CARD case years?

A 26 Yes, the disparity continues and becomes more pronounced. The table below is identical to the previous table, except that it shows 2026 backbone rates, instead of 2023 rates.

TABLE 3-4
2026 BACKBONE RATES
SLACK CAPACITY COSTS EMBEDDED IN BACKBONE RATES

Line No.		Redwood	Baja
1	**Cost and Capacity**		
2	Allocated Costs ($ million)	$299.7	$205.3
3	Capacity (MDth/d)	1,834	920
4	**Unit Capacity Cost** ($/Dth)	**$0.448**	**$0.611**
5	**System Average Load Factor**		
6	Total Rate ($/Dth)	**$0.739**	**$1.009**
7	Embedded Slack Capacity Cost ($/Dth)	$0.291	$0.398
8	**Path-Specific Load Factors**		
9	Total Rate ($/Dth)	**$0.510**	**$2.750**
10	Embedded Slack Capacity Cost ($/Dth)	$0.063	$2.139

Note that in 2026 the system average load factor produces rates on the Redwood and Baja paths that are each 65 percent higher than the corresponding unit capacity costs. In contrast, path-specific load factors produce a Redwood rate that is only 14 percent higher than the unit capacity cost, and a Baja rate that is 350 percent higher than the unit capacity cost.

Q 27 Are there other possible ways to allocate the costs of slack capacity between PG&E's backbone paths?

A 27 Yes. The system average load factor method allocates slack capacity costs by means of an equal percent increase over the unit capacity cost of each path. This is a reasonable method, but it allocates more slack capacity costs to the path with the highest unit capacity cost, in this case the Baja path. Slack capacity costs could also be allocated on an equal-cents-per-dekatherm basis, resulting in the same absolute increase on all paths compared to the unit capacity cost.

Q 28 You have demonstrated that the system average load factor is superior to path-specific load factors in terms of equitably allocating the costs of slack capacity. Are there any other reasons for preferring the system average load factor over path-specific load factors?

A 28 Yes, the system average load factor produces stable backbone rates, while path-specific load factors would produce unstable rates. Path-specific load factors could also lead to absurdly high backbone rates on the marginal path and large swings in backbone revenues.

Q 29 How would path-specific load factors create unstable backbone rates?

A 29 As Tables 3-3 and 3-4 illustrate, path-specific load factors produce relatively low rates on the preferred backbone path—currently Redwood—and relatively high rates on the marginal backbone path—currently Baja. If the market switched its preference and Baja became the preferred path, path-specific load factors would produce extremely large swings in the Baja and Redwood rates in the next CARD case following the market's switch.

The market's current preference for the Redwood path should not be considered permanent. Since PG&E unbundled its backbone rates in 1998, the market has switched its preference between the Redwood and Baja paths several times. Generally, from 1998 to 2002, the market preferred the Redwood path. From 2003 to 2010, the market preferred the Baja path. And from 2011 to the present, the market has preferred the Redwood path.

Even absent a switch in the market's path preference, path-specific load factors produce inherently unstable rates on the marginal backbone path. Small changes in overall backbone demand can produce large changes in throughput on the marginal path, resulting in large changes in the rates on that path. For example, suppose total backbone demand is 2,000 MDth per day, with 1,800 MDth per day transported on the Redwood path and 200 MDth per day transported on the Baja path. A 5 percent decrease in total demand (from 2,000 to 1,900 MDth per day) could produce a 50 percent decrease in Baja path throughput (from 200 to 100 MDth per day), which, all else constant, would cause a 100 percent increase in the Baja path rate in PG&E's next CARD case.

Q 30 Please comment further on your statement that path-specific load factors could produce absurdly high backbone rates on the marginal path and large swings in backbone revenues.

A 30 Again, Tables 3-3 and 3-4 illustrate how path-specific load factors could produce very high rates on the marginal path. These high rates would have two undesirable consequences. First, they would diminish competition between supply basins and would tend to perpetuate the out-of-favor status of the marginal backbone path. Second, they would produce large fluctuations in backbone revenues between hot and cold years, wet and dry years, periods of economic recession versus economic growth, and other similar events. The change in backbone throughput caused by such events would primarily affect the marginal path. If the marginal path had a very high transportation rate, the backbone revenue volatility would be disproportionately large, affecting customers and shareholders alike under the 50/50 backbone revenue sharing mechanism currently in place.[25]

Q 31 In conclusion, what are your recommendations regarding the appropriate load factor methodology for PG&E's backbone rates?

A 31 PG&E recommends the following:

- The Commission should continue its long-standing practice of using the system average load factor to set PG&E's backbone rates. The continuous use of this methodology during the past 25 years is not an accident. It produces reasonable, equitable, and stable backbone rates.
- The Commission should reject C&T's claim that the system average load factor causes Redwood path customers to subsidize Baja path customers, as well as C&T's suggestion that path-specific load factors would produce more reasonable backbone rates. C&T is incorrect on both counts. The system average load factor produces backbone rates that actually avoid subsidies between backbone paths by equitably allocating the costs of slack capacity. In contrast, path-specific load factors would produce backbone rates in which the marginal path subsidizes the preferred path by bearing most of the costs of slack capacity, and which have other defects described above.
- The Commission should also reject SBUA's vague assertions that backbone rates should more closely reflect market conditions on each backbone path, as well as SBUA's request that the Commission revisit the backbone load factor methodology.

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[25] PG&E Preliminary Statement, Part CP, GT&S Revenue Sharing Mechanism.

D. The Commission Should Approve PG&E's Proposed 50 percent Baja-Redwood Rate Differential Because It Is Consistent With Cost Causation Principles

Q 32 Briefly, what is PG&E's proposal regarding the Baja-Redwood rate differential?

A 32 PG&E proposes to set the Baja-Redwood rate differential at 50 percent of the natural rate differential because doing so properly reflects cost causation in totality. Specifically, the 50 percent rate differential recognizes the distinct receipt point rights and the common delivery point rights that backbone customers possess. The 50 percent rate differential is also consistent with the modified Baja-Redwood rate differentials that the Commission has adopted for the past 15 years.

Q 33 Do any parties criticize PG&E's proposal?

A 33 Yes, as mentioned earlier, C&T opposes PG&E's proposal. C&T proposes to set the Baja-Redwood rate differential at 100 percent of the natural rate differential.[26] C&T appears to agree with PG&E that backbone rates should be designed in accordance with cost causation principles, but disagrees that PG&E's proposed 50 percent rate differential achieves this objective.[27] In its prepared testimony, PG&E presented a detailed rationale for its proposal.[28] C&T put forth several incorrect criticisms of PG&E's rationale, to which PG&E responds in this section.

As also mentioned earlier, SBUA opposes PG&E's proposal. SBUA recommends continuation of the 2022 adopted Baja-Redwood rate differential of $0.18 per Dth during 2023-2026.[29] The 2022 Baja-Redwood rate differential was submitted as part of a stipulation in the 2019 GT&S Rate Case and was adopted by the Commission in its decision in that

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[26] See fn 7.

[27] See fn 8.

[28] PG&E Errata Testimony (Aug. 18, 2022), Ch. 3, Section C.

[29] See fn 9.

case.[30] SBUA proposes continuation of this rate differential on the grounds that subsidization of the Baja path would promote gas supply diversity.[31]

Q 34 Please summarize the proposals of PG&E, C&T, and SBUA with regard to the Baja-Redwood rate differential.

A 34 The table below shows the requested summary.

TABLE 3-5
BAJA-REDWOOD RATE DIFFERENTIAL
COMPARISON OF PARTIES' PROPOSALS
($/Dth, BAJA RATE HIGHER)

Line No.	Year	Natural Differential	PG&E Proposal (50% Natural)	C&T Proposal (100% Natural)	SBUA Proposal (2022 Value)
1	2023	$0.122	$0.061	$0.122	$0.180
2	2024	$0.189	$0.094	$0.189	$0.180
3	2025	$0.231	$0.116	$0.231	$0.180
4	2026	$0.288	$0.144	$0.288	$0.180

Notes: The figures in this table, with the exception of the SBUA proposal, reflect the revenue requirements, demand forecasts, and various other inputs to the backbone rates underlying PG&E's Errata Testimony (Aug. 18, 2022).

Q 35 Do you agree with C&T's and SBUA's criticisms of PG&E's proposed 50 percent Baja-Redwood rate differential?

A 35 No. C&T's and SBUA's criticisms of PG&E's proposal, as well as their alternative proposals, are inconsistent with cost causation principles and unsupported by the evidence. In addition, C&T's testimony reveals numerous misunderstandings of PG&E's tariffs, commercial practices, and system operations. PG&E responds in detail below.

1. Background

Q 36 Let's begin by being clear on terminology. What is the Baja-Redwood rate differential?

A 36 The Baja-Redwood rate differential is the difference between the transportation rates on PG&E's two principal backbone transportation

[30] See fn. 10.

[31] SBUA Direct Testimony, p. 12.

paths—the southern (Baja) path and the northern (Redwood) path. This difference is typically expressed as the difference between the Schedule G-AFT annual firm transportation rates for the two paths.

Q 37 And what is the natural rate differential?

A 37 The natural rate differential is the Baja-Redwood rate differential that results as a natural outcome of the simplistic traditional backbone cost allocation. The traditional cost allocation was first adopted in 1998 and was effective through 2007.[32]

Q 38 What Baja-Redwood rate differentials have been in effect since 2007?

A 38 Since 2007, there have been four GT&S rate cases covering 15 years (2008-2022).[33] Each of these cases has employed a modified backbone cost allocation in which a stipulated or litigated Baja-Redwood rate differential has been substituted for the natural rate differential. In every instance, the adopted rate differential has been significantly less than the natural rate differential.[34]

Q 39 Please describe the traditional backbone cost allocation.

A 39 In simple terms, the costs of PG&E's southern trunklines (Lines 300A and 300B) are allocated to the Baja path, the costs of PG&E's northern trunklines (Lines 2, 400, and 401) are allocated to the Redwood path, and the costs of PG&E's Bay Area Loop facilities are allocated to both paths in proportion to their capacities. Other backbone costs, such as storage costs recovered in backbone rates, are allocated to the paths in the same manner as the Bay Area Loop costs. Thus, the natural Baja-Redwood rate differential is driven by the difference in costs between the northern and southern trunklines. For the sake of simplicity, this explanation disregards the approximately 3 percent of backbone costs allocated to Schedule G-XF

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32 Gas Accord settlement (1998-2002), Gas Accord Settlement extension (2003), 2004 GT&S Rate Case (2004), and Gas Accord III Settlement (2005-2007).

33 Gas Accord IV settlement (2008-2010), Gas Accord V settlement (2011-2014), 2015 GT&S Rate Case (2015-2018), and 2019 GT&S Rate Case (2019-2022).

34 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-19, Table 3-3, provides a history of the 2008-2022 natural and adopted Baja-Redwood rate differentials. As noted there, the natural rate differential is unknown for 2008-2010.

service and Silverado path service. The backbone cost allocation is more fully described in PG&E's prepared testimony.[35]

Q 40 C&T states that the traditional backbone cost allocation has been in effect since 1998.[36] Is this statement correct?

A 40 The statement is misleading. The traditional backbone cost allocation was in effect in a pure sense only from 1998 through 2007. Every year since then it has been modified through imposition of a stipulated or litigated Baja-Redwood rate differential.

Q 41 Please provide a map showing the locations of PG&E's various backbone facilities.

A 41 The requested map is shown in the figure below. The northern trunklines extend from Malin to Panoche. The southern trunklines extend from Topock to Panoche and then on to Milpitas. The Bay Area Loop pipelines connect the northern and southern trunklines in the San Francisco Bay Area.

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35 *Id*. at pp. 6-7, line 16 to pp. 6-11, line 11 and Ch 6 Confidential Workpapers.

36 CT-0001, p. 4, lines 11-13.

FIGURE 3-1
PG&E BACKBONE FACILITIES

Q 42 Please summarize PG&E's rationale for proposing a Baja-Redwood rate differential equal to 50 percent of the natural rate differential.

A 42 The rationale for PG&E's proposal is simple. Backbone customers on the Baja and Redwood paths generally possess distinct and limited receipt point rights but common delivery point rights. Receipt points are limited to southern points (principally Topock) for the Baja path and northern points (principally Malin/Onyx Hill) for the Redwood path. In contrast, delivery points are the same for both paths. Backbone customers can deliver gas to any on-system backbone delivery point, regardless of path, if they hold an on-system contract, or to any off-system backbone delivery point, regardless of path, if they hold an off-system contract.[37] The foregoing statements are true even with respect to delivery points that are beyond the physical reach of the trunklines whose costs are included in a customer's backbone rates.

These common delivery point rights are at odds with the traditional backbone cost allocation, which implicitly assumes that Redwood path customers deliver gas only to points on the northern trunklines or the Bay Area Loop, and Baja path customers deliver gas only to points on the southern trunklines or the Bay Area Loop. Essentially, the traditional cost allocation assumes that the Redwood and Baja paths function distinctly, when in actuality only their receipt points are distinct while their delivery points are common. Accordingly, PG&E proposes to deviate from the traditional cost allocation and the natural rate differential that arises from it.

A 100 percent Baja-Redwood rate differential—that is, the natural rate differential—would correctly reflect the distinct receipt point rights on the two backbone paths but not the common delivery point rights. A 0 percent Baja-Redwood rate differential—that is, equal Baja and Redwood rates—would correctly reflect the common delivery point rights but not the distinct receipt point rights. PG&E proposes a 50 percent Baja-Redwood rate differential because it reflects both the distinct receipt point rights and the common delivery point rights that backbone contracts afford, while giving equal weight to each.

Q 43 Is PG&E's proposal consistent in concept with the Baja-Redwood rate differentials adopted for 2008-2022?

A 43 Yes. PG&E proposes to modify the traditional backbone cost allocation in the same manner it has been modified during the past 15 years—by setting the Baja-Redwood rate differential at a level lower than the natural rate differential. The only difference is, rather than set the differential in "black box" fashion pursuant to a stipulation, PG&E proposes to set it using a method that is consistent with cost causation principles and that can potentially be used in the future.

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37 As explained later, firm off-system customers are limited to only two off-system delivery points, but it is the same two points for customers on either the Redwood or Baja paths. Also, off-system customers who execute negotiated (as opposed to standard) contracts often negotiate a single off-system delivery point.

2. Parties' Specific Criticisms

Q 44 What are C&T's and SBUA's reasons for opposing PG&E's proposed 50 percent Baja-Redwood rate differential?

A 44 C&T makes the following claims and assertions:

- C&T argues that the 50 percent Baja-Redwood rate differential fails to align cost causation with cost responsibility, and thereby causes Redwood path customers to subsidize Baja path customers. C&T further claims that this subsidy exacerbates an already existing subsidy caused by the use of the system average load factor in the backbone rate design.[38]
- C&T claims that Redwood path customers cannot deliver gas to points on the Baja trunklines and Baja path customers cannot deliver gas to points on the Redwood trunklines.[39] Essentially, C&T disputes that backbone customers have common delivery point rights that are generally undifferentiated by path.
- C&T asserts that the PG&E Citygate is confined to an area in the middle of PG&E's system.[40]
- C&T claims that Redwood and Baja path customers can enjoy the broad delivery point rights PG&E says they possess only if these customers contract for additional services with PG&E.[41]
- C&T argues that Redwood path deliveries to the Southern California off-system market receive very little benefit from the Baja trunklines.[42]
- C&T asserts that PG&E's characterization of the 50 percent Baja-Redwood rate differential as shifting some Baja costs to Redwood services and some Redwood costs to Baja services is incorrect. C&T claims that PG&E's proposal only shifts costs from Baja to Redwood.[43]

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38 CT-0001, p. i, p. 3, lines 17-22, p. 5-, line 5 to p. 6, line 2, and p. 15, lines 13-17, p. 16, lines 4-7.

39 *Id*. at p. 10, lines 5-13, p. 15, lines 6-8, and p. 16, lines 2-3 and 11-13.

40 *Id*. at p. 9, line 20 to p. 10, line 13, and p. 14, lines 2-8.

41 *Id*. at p. 11, lines 14-17, and p. 14, line 11 to p. 15, line 5.

42 *Id*. at p. 12, line 14 to p. 13, line 10.

43 *Id*. at p. 9, lines 17-18.

- In addition, C&T fails to address the long-standing precedent of including Redwood and Baja costs in the Silverado path rate and the implications of this precedent with respect to the legitimacy of PG&E's 50 percent Baja-Redwood rate differential.[44]

SBUA makes a single claim:

- SBUA recommends that the Baja-Redwood rate differential remain at the current (2022) level during the CARD case period (2023-2026) on the grounds that "subsidization of the Baja line is appropriate" and in the interest of promoting gas supply diversity. SBUA offers little support for its recommendation and no specific criticisms of PG&E's proposed 50 percent Baja-Redwood rate differential.[45]

3. PG&E's Response to Parties' Specific Criticisms

a. C&T's First Claim Is Incorrect Because PG&E's Proposals Actually Prevent—Rather Than Cause—Backbone Path Subsidies.

Q 45 What is your response to C&T's first claim—that PG&E's proposed 50 percent Baja-Redwood rate differential is inconsistent with cost causation principles and would cause Redwood path customers to subsidize Baja path customers, exacerbating a subsidy that allegedly already exists due to the use of the system average load factor?

A 45 PG&E agrees with C&T that the backbone cost allocation should follow cost causation principles. PG&E stated this fact in its prepared testimony.[46] The previous section of this chapter (Section C) demonstrates that the system average load factor does not cause Redwood path customers to subsidize Baja path customers. This section (Section D) shows that PG&E's proposed 50 percent Baja-Redwood rate differential is consistent with cost causation principles and actually corrects subsidies inherent in the traditional backbone cost allocation. The remainder of this section shows that C&T's assertion that PG&E's proposal violates cost causation principles is based on numerous misunderstandings of PG&E's backbone system and services.

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44 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-24, lines 1-12.

45 SBUA Direct Testimony, p. 12.

46 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-20, line 19 to pp. 3-21, line 3.

b. C&T's Second Claim Is Incorrect Because Backbone Customers on the Redwood and Baja Paths Possess the Same Delivery Point Rights

Q 46 What is your response to C&T's second claim—that Redwood path customers cannot deliver gas to points on the Baja trunklines and Baja path customers cannot deliver gas to points on the Redwood trunklines?

A 46 C&T makes this puzzling claim several times, including the following statements:

> [N]one of the on-system gas received on the Redwood trunkline may be scheduled for delivery by non-core backbone shippers to any point on the Baja trunkline, and none of the on-system gas received on the Baja trunkline may be scheduled for delivery by non-core backbone shippers to any point on the Redwood trunkline.[47]

> And:

> Baja backbone facilities and Redwood backbone facilities are distinct and separate from each other. Shippers on one system do not use, and are contractually precluded from using, the other system.[48]

> And:

> Redwood on-system shippers receive no benefit from, and have no contractual right to deliver gas to, any part of the Baja system.[49]

These statements by C&T are categorically mistaken. A fundamental feature of PG&E's backbone services is backbone customers have limited receipt point rights that are dependent on path, but common delivery point rights that are the same for all paths. Backbone customers on any path may deliver gas to delivery points across PG&E's backbone system, even delivery points on the trunklines whose costs are not included in their backbone rates. (Stated another way, end-use customers may receive backbone service from any path, even though their premises may be physically connected to the trunklines of only one path.) The only delivery point limitation is on-system backbone contracts must deliver to on-system

47 CT-0001, p. 10, lines 8-12.

48 *Id*. at p. 15, lines 6-8.

49 *Id*. at p. 16, lines 2-3.

backbone delivery points while off-system contracts must deliver to off-system delivery points.[50]

As explained in PG&E's prepared testimony:

> [T]he use of the term "path" to geographically differentiate PG&E's backbone services is somewhat misleading. It is more accurate to characterize PG&E's backbone services as being geographically differentiated by receipt point.[51]

There is no service differentiation based on delivery point, other than the on-system/off-system differentiation just mentioned. In hindsight, "Redwood receipt point" and "Baja receipt point" would have been more descriptive terms than "Redwood path" and "Baja path."

Q 47 How do PG&E's tariffs describe a backbone customer's delivery point options?

A 47 It is instructive that PG&E's tariffs specify backbone receipt points by path (Redwood, Baja, Silverado, or Mission) but specify backbone delivery points in common terms applicable to all paths.[52] PG&E's tariffs describe backbone delivery point options as follows:

PG&E has five *on-system* backbone rate schedules. These schedules require on-system customers to deliver gas to on-system delivery points.[53] The available on-system delivery points are as follows:[54]

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50 See fn 37.

51 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-21, lines 23-26.

52 See "Territory" section of Gas Schedules G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-NFTOFF, G-AAOFF, and G-NAAOFF.

53 PG&E's five on-system backbone rate schedules contain this statement:

> Delivery Point(s): Any Delivery Point(s) to which gas is transported under this rate schedule must be On-System Delivery Point(s).

(Gas Schedules G-AFT, G-SFT, G-NFT, G-AA and G-NAA).

54 PG&E Gas Rule No. 1:

> ON-SYSTEM DELIVERY POINT: An on-system delivery point is defined as any point at which deliveries are made to, or for ultimate delivery to, PG&E's Local Transmission and Distribution system, PG&E's Market Center Citygate location, PG&E's storage facilities, or a third party's storage facilities located in PG&E's service territory.

- Interconnections between PG&E's backbone system and its local transmission and distribution system—referred to as the Citygate;[55]
- PG&E's Market Center Citygate location;
- PG&E's storage facilities; and
- Third-party storage facilities located in PG&E's service territory.

In addition, PG&E has two *off-system as-available* backbone rate schedules. These schedules require off-system customers to deliver gas to off-system delivery points.[56] An off-system delivery point is an interconnection with another gas utility or pipeline company.[57]

Lastly, PG&E has two *off-system firm* backbone rate schedules. These schedules require off-system customers to deliver gas to either Kern River Station, an interconnection with SoCalGas, or Fremont Peak, an interconnection with Kern River Gas Transmission.[58]

PG&E's four off-system rate schedules contain two additional minor delivery point provisions. First, they all contain provisions addressing potential backhaul service on interconnecting pipelines.[59] However, PG&E

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55 PG&E Gas Rule No. 1:

> CITYGATE: The Citygate is the point at which the Backbone Transmission System connects to the Local Transmission and Distribution System.

56 PG&E's two off-system as-available backbone rate schedules contain this statement:

> Delivery Point(s): Any Delivery Point(s) to which gas is transported under this rate schedule must be an Off-System Delivery Point(s).

(Gas Schedules G-AAOFF and G-NAAOFF).

57 PG&E Gas Rule No. 1:

> OFF-SYSTEM DELIVERY POINT: Any interconnection for delivery outside of PG&E's service territory.

58 PG&E's two off-system firm backbone rate schedules contain this statement:

> Firm Off-System Delivery Points: Kern River Station to SoCalGas [or] Fremont Peak to Kern River Gas Transmission.

(Gas Schedules G-AFTOFF and G-NFTOFF).

59 PG&E's four off-system backbone rate schedules contain this statement:

> Backhaul Off-System Delivery Points: All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

(Gas Schedules G-AFTOFF, G-NFTOFF, G-AAOFF, and G-NAAOFF).

performs only miniscule amounts of backhaul service. Second, the off-system firm rate schedules allow for designation of an alternative on-system delivery point if the customer pays the maximum allowable rate under the rate schedule and elects the Straight Fixed Variable (SFV) rate option.[60] However, PG&E has no such contracts on its books.

Q 48 What is the significance of these tariff provisions as they relate to C&T's claims?

A 48 These tariff provisions demonstrate that, contrary to C&T's claims, the delivery points available to backbone customers are common, not path-specific or facility-specific. That is, on-system backbone customers can deliver gas to any on-system backbone delivery point, regardless of path. Similarly, off-system backbone customers can deliver gas to any off-system backbone delivery point, subject to the firm service limitation discussed above. In every instance, Redwood and Baja customers transporting gas under the same standard backbone rate schedule have identical delivery point options; there are no delivery points available to one path that are not available to the other path.

C&T supposes there is a set of delivery points on the Baja trunklines that are available only to Baja customers and a set of delivery points on the Redwood trunklines that are available only to Redwood customers. C&T claims that "[s]hippers on one system do not use, and are contractually precluded from using, the other system."[61] C&T is mistaken. A simple example that exposes C&T's error is backbone deliveries to third-party storage facilities. All third-party storage facilities are connected to the Redwood trunklines, yet all are equally accessible by Redwood *and* Baja path customers. PG&E's tariffs expressly permit Redwood and Baja path customers to deliver gas to the same delivery points, including delivery points on the trunklines of the other path. As described below, such transactions are in fact commonplace.

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60 See PG&E rate schedules G-AFTOFF and G-NFTOFF, Alternative Delivery Points.

61 CT-0001, p. 15, lines 7-8.

c. C&T's Third Claim Is Incorrect Because the PG&E Citygate Is Geographically Broad, Encompassing All Points of Interconnection Between the Backbone and Local Transmission/Distribution Systems

Q 49 What is your response to C&T's third claim—that the PG&E Citygate is confined to an area in the middle of PG&E's system?

A 49 Again, C&T's repeated claims are puzzling and fundamentally contrary to the character of PG&E's system. The following are examples of C&T's claims:

> PG&E's system basically consists of a northern backbone trunkline (Redwood), a southern backbone trunkline (Baja) and a large central area in the middle of the system called the PG&E Citygate.[62]
>
> And:
>
> All on-system non-core backbone transportation volumes must be delivered to the middle of PG&E's system.[63]

As discussed earlier, the PG&E Citygate consists of all points where PG&E's backbone transmission system interconnects with its local transmission and distribution system.[64] There are myriad such points of interconnection up and down the length of PG&E's system. The Citygate is a diffuse collection of these physical points that for contractual purposes is treated as the primary delivery point for on-system backbone transactions and the receipt point for PG&E's downstream end-user gas transportation (local transmission and distribution) services.

The Citygate is not confined to any particular area in the middle of PG&E's system. It is the collection of all local transmission and distribution interconnections to PG&E's backbone pipelines, including the Redwood trunklines, Baja trunklines, and Bay Area Loop pipelines. The Citygate also includes the points where California gas production (delivered on the Silverado path) and underground storage withdrawals (delivered on the Mission path) enter PG&E's local transmission and distribution system.

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62 *Id*. at p. 9, line 22 to p. 10, line 2.

63 *Id*. at p. 10, lines 12-13.

64 See fn 55.

Q 50 Please provide a map showing the physical Citygate locations on PG&E's system, that is, the points of interconnection between PG&E's backbone system and its local transmission and distribution system.

A 50 Figure 3-2 below shows the requested map. The majority of interconnections between the backbone system and the local transmission and distribution system are shown. However, hundreds of large customer[65] and "farm tap" interconnections to the backbone are not shown.

65 PG&E has 6 Schedule G-NT-BB Industrial customers and 13 Schedule G-EG-BB Electric Generation customers directly connected to its backbone transmission system.

FIGURE 3-2
PG&E CITYGATE: INTERCONNECTIONS BETWEEN PG&E BACKBONE SYSTEM AND LOCAL TRANSMISSION AND DISTRIBUTION SYSTEM

Q 51 What is the significance of this map as it relates to C&T's understanding of the PG&E Citygate.

A 51 The map shows that, contrary to C&T's understanding, the PG&E Citygate is not confined to an area in the middle of PG&E's system. The Citygate extends as far north as the backbone-local transmission interconnections that serve the cities of Redding and Eureka, and as far south as the backbone-local transmission interconnections that serve the cities of Bakersfield, Ridgecrest, and Victorville. The geographic breadth of the Citygate reinforces the fact that Redwood path service often uses the Baja trunklines and Baja path service often uses the Redwood trunklines.

Q 52 How does the geographic breadth of the Citygate reinforce the fact that Redwood and Baja services often use the trunklines of the other path?

A 52 The simple answer is the Citygate extends sufficiently south that Redwood contracts delivering to southern Citygate delivery points must rely on the Baja trunklines. Similarly, the Citygate extends sufficiently north that Baja contracts delivering to northern Citygate delivery points must rely on the Redwood trunklines.

A more detailed answer is provided in the table below. This table divides PG&E's backbone system into four key segments. (See Figure 3-1 to locate the segments on a map.) It then identifies the characteristics of Redwood and Baja service to each segment. Specifically, it indicates whether Redwood and Baja contracts serving the segment must use the trunklines of the other path in addition to the trunklines of their own path.

TABLE 3-6
BACKBONE SEGMENTS AND SERVICE CHARACTERISTICS

			Characteristics of Service to Segment	
Line No.	**Backbone Segment** (a)	**Facilities in Segment**	**Redwood Services Use Baja Trunklines?**	**Baja Services Use Redwood Trunklines?**
1	Malin to Panoche	Lines 2, 400, 401	No	**Yes**
2	Topock to Panoche	Lines 300A/B (Part)	**Yes**	No
3	Panoche to Irvington	Lines 300A/B (Remainder) Bay Area Loop (Part)	No	No
4	Irvington to Antioch	Bay Area Loop (Remainder)	No	**Yes**

Notes: (a) See map at Figure 3-1 for location of each backbone segment.

Note that only one of the four segments (Panoche to Irvington) can receive both Redwood and Baja services without either backbone path having to rely on the trunklines of the other path. Service to all of the other segments requires that one of the two paths rely on the trunklines of the other path.

Q 53 How much of PG&E's on-system gas demand is connected to the segments that require one backbone path to rely on the trunklines of the other path in order to provide delivery to the segment?

A 53 During 2019-2021, approximately 71 percent of on-system gas demand was located on these segments. This figure was obtained from Supervisory Control and Data Acquistion (SCADA) measurement at the various interconnections and taps on PG&E's backbone system.[66] This figure explains why, as stated earlier, it is commonplace for Redwood path transactions to use Baja trunklines or Baja path transactions to use Redwood trunklines.

Q 54 How does C&T's misunderstanding of the nature of the PG&E Citygate affect its reasoning about permissible backbone delivery points?

A 54 C&T makes several statements similar to the following:

> Both Baja and Redwood on-system shippers can only deliver gas to one of three points, not to any point on either system. One of these points is the PG&E Citygate and the other two points are storage.[67]

C&T does not appear to recognize the contradiction in its own statement. C&T is correct that Baja and Redwood on-system shippers can deliver gas only to the PG&E Citygate, PG&E storage facilities, or third-party storage facilities. However, C&T does not recognize that the Citygate *itself*, by tariff definition and by virtue of being geographically broad, includes "any [delivery] point on either system."[68]

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66 The majority of gas demand on PG&E's system has SCADA measurement, though some demand does not.

67 CT-0001, p. 9, lines 2-4.

68 Provided the delivery point is an on-system delivery point, which C&T acknowledges elsewhere (e.g., CT-0001, p. 9).

d. C&T's Fourth Claim Misconstrues PG&E's Testimony and Tariffs

Q 55 What is your response to C&T's fourth claim—that Redwood and Baja path customers can enjoy broad delivery point rights only if they contract for additional services with PG&E?

A 55 C&T's arguments on this topic misconstrue PG&E's testimony and tariffs. First, C&T argues that backbone customers do not have rights to deliver gas to any on-system delivery point without also contracting for local transmission and distribution service and paying the rates for that service. For example, C&T makes the following statement or variations of it several times:

> PG&E's statements regarding the contractual rights of backbone shippers to deliver gas to virtually any point on PG&E's system without having to pay any rate other than the Redwood or Baja backbone path rate are misleading at best. On-system backbone shippers have three delivery points available, only one of which is not to storage. . . . . None of the other points in PG&E's service territory can be accessed by backbone shippers without additional contracts in place on the local transmission and distribution systems and without paying the rates applicable to those contracts.[69]

PG&E's point was that on-system Redwood and Baja customers have contractual rights to deliver gas to any on-system *backbone* delivery point. PG&E did not claim that backbone customers can deliver gas to any point on PG&E's local transmission and distribution system. It is well understood that transportation service downstream of the Citygate is required of all PG&E end-use customers, and is distinct from backbone service, and is subject to additional rates. Backbone transmission service typically brings gas from the California border to the PG&E Citygate; local transmission and distribution service brings the gas from the Citygate to the customer premises. The existence of this downstream service and its separate rates does not change PG&E's point that Redwood and Baja on-system services each grant broad *Citygate* delivery point rights anywhere the Citygate exists, including on the trunklines of the other path. Yet the traditional backbone cost allocation does not reflect these rights.

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[69] CT-0001, p. 14, line 18 to p. 15, line 5.

Second, C&T claims that in at least some instances Redwood customers have to pay twice for Redwood service in order to deliver gas to off-system delivery points. C&T makes the following statement:

> [I]n order to deliver gas to Topock, for further delivery by backhaul into either El Paso Natural Gas Company or Transwestern Pipeline Company, the on-system Redwood shipper would have to also contract for off-system Redwood service, thus paying twice for the costs of the Redwood backbone, for one transaction.[70]

C&T appears to be referring to a situation in which a hypothetical Redwood path customer with an on-system contract wants to deliver gas to an off-system delivery point. However, as PG&E pointed out in its prepared testimony (and C&T acknowledged in its testimony) on-system contracts must deliver gas to on-system delivery points and off-system contracts must deliver gas to off-system delivery points.[71] The solution to this customer's dilemma is to enter into an off-system Redwood contract, allowing for payment of the Redwood rate only once. Alternatively, if the customer has *already* transported its gas under a Redwood on-system contract to the PG&E Citygate, and *now* wants to transport that same gas to Topock for off-system delivery, the customer can enter into a Mission path off-system contract for that purpose. Nothing about the scenario C&T describes contradicts PG&E's rationale for the proposed 50 percent Baja-Redwood rate differential.

e. C&T's Fifth Claim Is Incorrect Because Redwood Off-System Services Are Substantial and Could Not Occur Without the Baja Trunklines

Q 56 What is your response to C&T's fifth claim—that Redwood off-system services receive very little benefit from the Baja system?

A 56 By way of background, virtually all of PG&E's off-system market is located in Southern California. This market is served primarily by Redwood services. Since the Redwood trunklines have their southern terminus at Panoche (see Figure 3-1), Redwood off-system service must rely on the Baja trunklines in addition to the Redwood trunklines to deliver gas into

70 *Id*. at p. 11, lines 8-12.

71 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-22, fn. 24.

Southern California. In contrast, Baja off-system service to Southern California uses only the Baja trunklines. All firm off-system services and most as-available off-system services are delivered to Kern River Station (connecting to SoCalGas) or Fremont Peak (connecting to Kern River Gas Transmission).

The quantities of PG&E's off-system service are substantial. During July 2018 through June 2021, PG&E provided an average of 199 MDth per day of non-G-XF off-system service, 82 percent of it on the Redwood path.[72] For the 2023-2026 CARD case period, PG&E forecasts average non-G-XF off-system service of 278 MDth per day, 87 percent of it on the Redwood path.[73] Given the magnitude of these numbers, C&T's claim that Redwood off-system services receive little benefit from the Baja system is not credible as these off-system deliveries clearly depend on the physical existence of the Baja trunklines.

Q 57 What specific arguments does C&T make about off-system backbone services, and what is your response?

A 57 C&T correctly notes that PG&E offers firm off-system backbone service to two delivery points (Kern River Station and Fremont Peak) and that both of these delivery points are on the Baja trunklines.[74] However, C&T then makes several incorrect statements:

> In order for a Redwood off-system shipper to deliver gas to either of these points, the service could only be provided as a backhaul, which is only available if the upstream pipeline will accept the gas, and is further limited to the quantities of gas being delivered by that upstream pipeline to PG&E. Redwood deliveries by backhaul to either of these interconnect points do not need or use the Baja trunkline; the gas is delivered by displacement, which creates additional capacity on the Baja trunkline downstream of the pipeline interconnect point. In any case, deliveries by backhaul on an as-available basis do not constitute appropriate grounds for allocating Baja trunkline costs to Redwood shippers, especially given the fact that off-system shipments constitute

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72 In addition, PG&E provided approximately 80 MDth per day of Schedule G-XF Redwood off-system service, but this service is subject to an incremental rate design that is not affected by the Baja-Redwood rate differential.

73 PG&E, Ch. 3, Workpaper 5A, Tab "Off-Sys Throughput Detail."

74 CT-0001, p. 12, lines 17-21.

only a small portion of the total volumes moving on the backbone systems….[75]

First, C&T is mistaken that backbone off-system service to Kern River Station or Fremont Peak "could only be provided as a backhaul" on the upstream pipeline. Both interconnect points are bi-directional. Further, at both points the direction of flow is almost always from PG&E to the interconnecting pipeline. Thus, the vast majority of off-system deliveries to these points are forward haul deliveries.

Second, C&T is mistaken that Redwood path service to Kern River Station or Fremont Peak occurs by displacement on PG&E's system[76] and that such deliveries therefore "do not need or use the Baja trunkline." In actuality, PG&E's deliveries to these two off-system points are sometimes accomplished by displacement and other times accomplished by reverse physical flows. It is common for PG&E to physically flow Redwood gas south onto the Baja trunklines to serve on-system and off-system demand in the southern part of PG&E's system. During 2020-2021, PG&E estimates that the peak month for these reverse flows was 141 MDth per day and the peak day was 323 MDth per day. These estimates are based on analysis of SCADA data.

Even when Redwood path deliveries to Kern River Station and Fremont Peak are accomplished by displacement, it is not true that these deliveries do not use the Baja trunkline. Redwood deliveries south of Panoche (the southern terminus of the Redwood trunklines) could not occur, even by displacement, but for the existence of the Baja trunklines and the fact that Baja customers were flowing gas on those trunklines. Further, although C&T correctly notes that displacement transactions create additional capacity downstream of the delivery point, this capacity is not useful to anyone. As discussed above in Section C, the Baja path already operates at a very low load factor.

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75 *Id*. at line 21 to p. 13, line 19 (citation omitted).

76 A displacement occurs when, for example, Baja gas, contractually destined for San Jose, is physically delivered to Kern River Station, while an equal amount of Redwood gas, contractually destined for Kern River Station, is physically delivered to San Jose.

Third, C&T mistakenly refers to the off-system deliveries at Kern River Station and Fremont Peak as “deliveries by backhaul on an as-available basis.” As discussed already, the vast majority of these deliveries are forward hauls. In addition, a majority are provided under PG&E’s firm off-system rate schedules, not as-available rate schedules.

Lastly, C&T mistakenly claims that “off-system shipments constitute only a small portion of the total volumes moving on the backbone systems.” To the contrary, and as already noted, PG&E forecasts non-G-XF off-system service of 278 MDth per day during 2023-2026, of which 242 MDth per day is Redwood off-system service. The Redwood off-system forecast, which is largely based on already executed firm contracts, represents 14 percent of non-G-XF Redwood throughput during 2023-2026. Likewise, the total off-system forecast represents 14 percent of non-G-XF total backbone throughput during the same period.

f. C&T’s Sixth Claim Is Mistaken Because It Only Recognizes That the *Net* Cost Shift Is From Baja to Redwood

Q 58 What is your response to C&T’s sixth claim—that PG&E’s proposed 50 percent Baja-Redwood rate differential only shifts Baja costs to the Redwood path, but does not, as PG&E characterizes it, also shift Redwood costs to the Baja path?

A 58 C&T is mistaken. Recall (Question 39) that the backbone costs consist of path specific costs (for the Redwood and Baja trunklines, respectively) and common costs (for the Bay Area Loop pipelines as well as other common costs such as storage). PG&E’s 50 percent Baja-Redwood rate differential essentially converts half of the path-specific costs to common costs. As a result, the converted costs are shared by both paths. Baja costs are shared with the Redwood path and Redwood costs are shared with the Baja path. C&T merely recognizes the inevitable fact that the *net* cost shift can only be in one direction—from the higher cost path (Baja) to the lower cost path (Redwood).[77]

g. C&T Neglects to Address the 25-Year Precedent of Including Redwood and Baja trunkline Costs in the Silverado Path Rate

Q 59 Did C&T neglect to address any of the reasons PG&E put forth in support of its proposed 50 percent Baja-Redwood rate differential?

A 59 Yes, C&T did not address the 25-year precedent of including Redwood and Baja trunkline costs in the Silverado path rate.[78] The Silverado path is used to deliver California gas production located in PG&E's service territory to the PG&E Citygate, to PG&E or third-party storage facilities, or to off-system delivery points. Unlike the Baja and Redwood paths, the Silverado path does not have dedicated trunklines or other dedicated facilities. The Silverado cost allocation includes a proportionate share of Bay Area Loop costs and other common costs, plus a fractional share of Redwood and Baja trunkline costs.

Q 60 What is the reason for including Redwood and Baja trunkline costs in the Silverado cost allocation?

A 60 The allocation of Redwood and Baja trunkline costs to the Silverado path recognizes the fact that Silverado path customers, like Redwood and Baja path customers, possess broad delivery point rights across PG&E's backbone system. It is appropriate for Silverado path customers to pay a share of Redwood and Baja trunkline costs because under PG&E's tariffs they are permitted, like other backbone customers, to transport gas to delivery points on the Redwood and Baja trunklines.

Q 61 What is the significance of the Silverado cost allocation to C&T's claims in this case?

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77 For simplicity, PG&E's backbone rate model actually calculates rates in a manner slightly different than the foregoing description. First, all (not half) of the path-specific costs are pooled and shared by both paths. Second, equalized (0 percent Baja-Redwood rate differential) Redwood and Baja rates are calculated from the pooled costs. Third, costs are shifted from the Redwood path *back* to the Baja path until the desired (50 percent) Baja-Redwood rate differential is achieved. These steps are performed separately for core and noncore rates. (See PG&E Ch. 6 Confidential Workpaper, backbone rate model.)

78 PG&E Errata Testimony (Aug. 18, 2022), pp. 3-24, lines 1-12.

A 61 The Silverado cost allocation is a long-standing precedent that supports the notion that backbone rates should be designed in a manner that ensures backbone customers contribute to the costs of the facilities on which they have delivery point rights. C&T has tried unsuccessfully to deny that Redwood customers have delivery point rights on the Baja trunklines or that they otherwise benefit from the Baja facilities, but they do. The Redwood and Baja cost allocation should be modified accordingly. PG&E's proposed 50 percent Baja-Redwood rate differential accomplishes this objective.

h. SBUA's Recommendation to Keep the Baja-Redwood rate Differential at the 2022 Level Lacks Support

Q 62 What is your response to SBUA's recommendation to keep the Baja-Redwood rate differential at the adopted 2022 level during 2023-2026 on the grounds that subsidization of the Baja path promotes gas supply diversity?

A 62 SBUA offers virtually no support for its recommended $0.18 per Dth Baja-Redwood rate differential. Nor does SBUA explain why this rate differential amounts to a Baja subsidy or how this rate differential would mesh with SBUA's other recommendation, discussed in Section C, that backbone rates more closely reflect market conditions on each backbone path. SBUA also does not offer any specific criticisms of PG&E's proposed 50 percent Baja-Redwood rate differential.

SBUA does not present any evidence that California's gas supply diversity is inadequate or that SBUA's recommendation, if adopted, would facilitate supply diversity. Moreover, the $0.18 per Dth Baja-Redwood rate differential that the Commission adopted for 2022 was a stipulated differential that did not bear a precise relationship even to PG&E's 2022 adopted costs, and bears no relationship to the 2023-2026 costs that are the subject of this proceeding.

For all of the reasons already explained, PG&E's proposed 50 percent Baja-Redwood rate differential is superior to SBUA's proposal.

i. Baja-Redwood Rate Differential – Conclusion

Q 63 In conclusion, what are your recommendations regarding the appropriate Baja-Redwood rate differential?

A 63 PG&E recommends the following:

- The Commission should adopt PG&E's proposed 50 percent Baja-Redwood rate differential. PG&E's proposal is consistent with cost causation principles, drawing justification from the specific receipt and delivery point rights that backbone customers enjoy. PG&E's proposal is also consistent with the past 15 years of stipulated Baja-Redwood rate differentials, but goes further than those previous stipulations by offering a method and rationale for setting an appropriate rate differential, both in this case and potentially in future cases as well.
- The Commission should reject C&T's various criticisms of PG&E's proposed 50 percent Baja-Redwood rate differential. PG&E has answered those criticisms and demonstrated that every material criticism is mistaken. Likewise, the Commission should reject C&T's proposed 100 percent Baja-Redwood rate differential for lack of adherence to cost causation principles.
- The Commission should also reject SBUA's recommendation to hold the Baja-Redwood rate differential at the adopted 2022 level during 2023-2026 for lack of support and lack of any basis in the 2023-2026 backbone costs.

E. Conclusion

Q 64 Do you have any concluding remarks?

A 64 Yes. In this rebuttal testimony PG&E has responded to the testimony of C&T and SBUA. Both parties criticize the use of the system average load factor to set backbone rates, claiming it causes inter-path subsidies or fails to reflect market conditions on each backbone path. Both parties are mistaken, as demonstrated in this testimony. Additionally, both parties criticize PG&E's proposed 50 percent Baja-Redwood rate differential and recommend alternative rate differentials. Again, PG&E has thoroughly rebutted both parties' mistaken arguments.

C&T claims that both of PG&E's proposals—the system average load factor and the 50 percent Baja-Redwood rate differential—would cause inter-path rate subsidies. In actuality, both proposals would prevent, not cause, inter-path subsidies and would ensure that PG&E's backbone rates are equitable, stable, and consistent with cost causation principles.

Accordingly, PG&E requests that the Commission adopt PG&E's proposals and reject the proposals of C&T and SBUA.

Q 65 Does this conclude your rebuttal testimony?

A 65 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

REBUTTAL TESTIMONY OF

ANNETTE TAYLOR AND JAMES CHEN ON

LOCAL TRANSMISSION COST ALLOCATION STUDY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REBUTTAL TESTIMONY OF
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REBUTTAL TESTIMONY OF
ANNETTE TAYLOR AND JAMES CHEN ON
LOCAL TRANSMISSION COST ALLOCATION STUDY

A. Introduction

Q 1 Please state the purpose of this rebuttal testimony.

A 1 This rebuttal testimony responds to the direct testimony by Calpine,[1] Indicated Shippers,[2] The Utility Reform Network (TURN),[3] Small Business Utility Advocates (SBUA),[4] and Northern California Generation Coalition (NGCC)[5] regarding Pacific Gas and Electric Company's (PG&E) proposed local transmission cost allocation methodology for its Core and Noncore customers.

Q 2 Who are the witnesses sponsoring this rebuttal testimony?

A 2 The following witnesses are sponsoring this rebuttal testimony as designated:

- Annette Taylor, Expert Data Scientist, sponsors the questions as noted throughout this chapter.
- James Chen, Expert Product Manager, sponsors the questions as noted throughout this chapter.

[Witness: A. Taylor]

Q 3 Are there sections in your testimony that need to be corrected?

A 3 Yes, I have three corrections. In PG&E's Errata Testimony dated August 18, 2022, Chapter 4 ("Local Transmission Allocation Study),

- Page 4-28, line 11, it currently reads "thousand decatherms per day (MDth/d)". It should read "thousand therms per day (Mth/d)."

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1 Calpine Prepared Testimony.

2 IS-1.

3 TURN Prepared Testimony.

4 SBUA Direct Testimony.

5 NCGC-1.

- Page 4-28, line 12, it currently reads “MDth.”[6] It should read “Mth”[7] in the Abnormal Peak Day (APD) forecast units used.
- Page 4-30, Table 4-10, line 3, it currently reads “LT Total Demand Served on APD (MDth).” It should read “LT Total Demand Served on APD (Mth).”

These typographic errors have not impacted calculations made in the forecasts. The values and units of measure in Table 4-1 of PG&E’s testimony remain correct and need not be changed.

[Witness: A. Taylor]

B. Summary of Parties’ Positions and PG&E’s Responses

Q 4 Please summarize parties’ positions regarding PG&E’s local transmission cost allocation methodology for PG&E’s Core and Noncore customers and provide PG&E’s responses.

A 4 Briefly, a summary of the parties’ positions and respective PG&E’s responses is as follows:

1) Calpine supports PG&E’s proposed APD methodology in general, with the exception that they recommend adjusting the Noncore cost allocation. Calpine states that a significant portion of PG&E’s Noncore demand, calculated based on APD method, will in fact be served directly from the backbone system which is upstream of the local transmission system.[8] Implying that such demand served directly from the backbone system should not be included in the cost allocation.

   PG&E’s Response:

   Calpine’s adjustments are incorrect because PG&E’s proposed APD method allocation already excludes the Noncore backbone demand upstream of the local transmission system. Calpine’s adjustment, therefore, would introduce an error.

2) Indicated Shippers supports PG&E’s proposed APD methodology in general, with the exception that they recommend a reduced Noncore

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6 Thousand dekatherms.

7 Thousand therms.

8 Calpine Prepared Testimony, p. 17, line 11 to p. 21, line 8.

demand resulting in a reduced total system demand. They use the total demand based on the 2020 California Gas Report.[9]

PG&E's Response:

Indicated Shippers' adjustments should be rejected because the adjustments are based on a misinterpretation of PG&E's data in the 2020 California Gas Report. Indicated Shippers mixed volumetric information from two different design scenarios with completely different basis. They combined results from APD, which is a 1-day in a 90-year standard, with the results from Reliability Standard which is a 1-day in a 10-year standard. Mixing results in the manner Indicated Shippers did does not make sense.

3) TURN's testimony on local transmission includes the following points:[10]

a. TURN states the APD is a "very extreme allocation method" because an extreme event impacting all PG&E's LT systems at the same time has never occurred.

b. TURN asserts that APD forecast is unreliable because it contains several inaccuracies.

c. TURN asserts the period chosen for the APD analysis was significantly impacted by the COVID-19 pandemic and can vary considerably from year-to-year. Therefore, it believes if the California Public Utilities Commission (CPUC or Commission) approves the APD methodologies for allocation local transmission cost, it is best to use a 5-year average APD forecast.

d. TURN describes the results from the APD and the Cold Year Peak Month (CYPM) models as anomalous since they expect the Core allocation from APD method to be relatively higher compared to the Core allocation obtained from CYPM, since the APD method uses data of a relatively more extreme temperature scenario.

e. TURN recommends using the Average and Peak Demand Method to calculate local transmission cost.

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9 IS-1, p. 4-11, line 1 to p. 4-16, line 12.

10 TURN Prepared Testimony, pp. 14-29.

PG&E's Response:

a. PG&E's 1-in-90 years design standard has been upheld by the Commission in D.22-07-002.

b. Many of TURN's criticisms are based on flawed assumptions and without any analytical support, as discussed below in Q23-Q27.

c. PG&E used the 2020-2021 APD forecast, the most recent and complete forecast available at the time of the filing. PG&E also believes it may be reasonable to use an average multi-year APD forecast to allocate local transmission cost in subsequent Gas Transmission and Storage (GT&S) allocation and rate design cases.

d. APD and CYPM models are complex models that have other inputs in addition to temperature. Moreover, each model uses different data sources and assumptions. Therefore, one cannot guarantee that the correlation between changes in temperature and demand are the same in both models.

e. The Average and Peak Demand method does not align with cost causation principles. Further TURN's Average and Peak Demand calculation uses data from two different models.

4) SBUA prefers TURN's proposed Core and Noncore allocation cost percentages presented at the August 2020 workshop.[11]

PG&E's Response:

SBUA's arguments should be rejected because SBUA fails to consider PG&E's update to TURN's proposal as described in PG&E's Prepared Testimony.[12]

5) NCGC prefers using the CYPM method to allocate local transmission cost.[13]

PG&E's Response:

While PG&E proposed the APD method over the CYPM, both models for allocating local transmission cost are used by other U.S.

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[11] SBUA Direct Testimony, pp. 12-13.

[12] PG&E's Errata Testimony (Aug. 18, 2022), p. 4-28, line 1 to p. 4-30, Table 4-10.

[13] NCGC-1, p. 18, lines 15-24.

utilities to allocate transmission cost.[14] However, Indicated Shippers and most utilities that were surveyed by Black & Veatch[15] used some form of peak design day and the APD method aligns more closely with cost causation principles.

Q 5 Are there proposals the parties do not dispute?

A 5 Calpine and Indicated Shippers agree that the APD method should be used to allocate local transmission cost.

C. PG&E's Response to Parties' Recommendations or Positions

[Witness: A. Taylor]

Q 6 Briefly, what is local transmission cost allocation and how is it used?

A 6 PG&E's local transmission system, which is organized into 12 smaller systems, transports gas from the backbone system to the gas distribution pipelines.[16] PG&E's local transmission cost allocation is used to allocate local transmission costs between Core and Noncore customers. PG&E local transmission cost allocation percentages are then used to determine the local transmission rates for Core and Noncore customers. See Chapter 6 for more detail about the use for setting rates.[17]

Q 7 How do you determine local transmission cost allocation?

A 7 The current method for allocating local transmission cost is CYPM. However, two other methods have been recommended for local transmission cost allocation in this proceeding, APD and Average and Peak Demand. For purposes of this rebuttal, PG&E describes APD, CYPM, and Average and Peak Demand.

- <u>Abnormal Peak Day</u> – APD is used to determine the physical capacity requirements of local transmission pipeline systems with a preponderance of temperature-dependent core load. Since core customers use gas primarily for space heating, LT APD is based on the coldest day in the history of PG&E's service territory, which has a

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14 Both models were covered during the workshops on local transmission allocation, by other intervening parties.

15 PG&E's Errata Testimony (Aug. 18, 2022), p. 4-17, line 5 to p. 4-18.

16 PG&E's Errata Testimony (Aug. 18, 2022), p. 4-3, lines 18-20.

17 PG&E's Errata Testimony (Aug. 18, 2022), Chapter 6.

1-in-90-year recurrence interval. For local transmission system design, area-specific APD temperatures are used. The APD design standard assumes that all core customers are to be served, with the remaining supply to be used by Noncore.[18]

- Average and Peak Demand – A two-part allocation method where the first allocation is based on cost due to the average usage and the second allocation is based on the cost related to peak demand. The percentage of cost allocated based on the average usage is determined by the load factor. The load factor is the average load divided by the peak load. The remaining cost is allocated based on coincident peak demand.[19]
- Cold Year Peak Month – CYPM is the allocation method that has been used to allocate PG&E's local transmission costs in the past. The local transmission allocation is based on a coincident peak of the coldest month in a 1-in-35-year cold year event.[20]

Q 8 What is PG&E's proposal regarding local transmission cost allocation?

A 8 PG&E proposes using the APD methodology instead of the CYPM to allocate local transmission cost.[21] Based on the APD method, PG&E's proposed Local Transmission cost allocation for 2023 through 2026 is 66 percent for Core and 34 percent for Noncore.[22]

PG&E recommends APD for allocating local transmission in this proceeding because it satisfies the principle of cost causation since it is used to: (1) determine gas capacity requirements for Core customers, and (2) generate the Noncore demand that can be served under APD conditions.[23] The APD methodology is a coincident peak design day

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18 PG&E Errata Testimony (Aug. 18, 2022), p. 4-5, lines 12-13, p. 4-28, lines 10-12. See also PG&E's Opening Testimony in GRC Ph. I, A.21-06-021, Exhibit (PG&E-3), p. 11-16, lines 31-33.

19 TURN Prepared Testimony, p. 26, lines 18-19.

20 PG&E Errata Testimony (Aug. 18, 2022), p. 4-6 and Table 4-3.

21 PG&E Errata Testimony (Aug. 18, 2022), p. 4-28, lines 2-3.

22 PG&E Errata Testimony (Aug. 18, 2022), p. 4-3, Table 4-1.

23 PG&E's Errata Testimony (Aug. 18, 2022), p. 4-38, lines 17-32.

method, one of the most common methods for allocating local transmission cost.[24]

The APD methodology includes 12 hydraulic models to determine the capacity needs of the local transmission system. These models analyzed operating pressure and demand changes for each of the pipe segments that are included within approximately 225 local transmission subsystems.[25] The hydraulic models produce the future demand forecast for each of the local transmission subsystems and determine which individual pipe segments of the subsystems will need to be upgraded or modified to meet the expected load changes of the future demand forecast.

PG&E developed the proposed APD allocation methodology as it reflects the current local transmission capacity investment process, as well as annual curtailment allocation for local transmission noncore customers. The local transmission allocation percentages for Core and Noncore customers were derived from the same 12 models used for capacity investments and developing annual Noncore curtailment levels – using the same planning methods and assumptions. As such, PG&E asserts the APD allocation methodology best represents the concepts of local transmission capacity cost causation principles.[26]

1. Calpine Modifications to APD Should Be Rejected Because Calpine Erroneously Subtracts Backbone-Level Demand From PG&E's Proposed APD Forecasted Noncore Demand.

Q 9 Does Calpine support using APD for PG&E's local transmission cost allocation?

A 9 Yes, Calpine supports using APD for PG&E's local transmission cost. However, Calpine adjusts the allocations for Noncore. Calpine subtracts backbone-level EG demand from PG&E's proposed APD forecasted Noncore demand for the local transmission system.[27] As Table 4-1 shows,

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24 PG&E's Errata Testimony (Aug. 18, 2022), p. 4-38, lines 1-18.

25 PG&E Errata Testimony (Aug. 18, 2022), p. 4-5, lines 1-6.

26 Unlike Indicated Shippers and TURN, PG&E did not use any data from the existing California Gas Reports for Local Transmission, because doing so would not follow applicable cost causation principles.

27 Calpine Prepared Testimony, p. 17, line 11 to p. 18, line 9.

Calpine removes 6 MMcf/d of industrial backbone and 746 MMcf/d of EG backbone.[28] The backbone-level EG demand that was removed was the average of the three highest daily backbone-level EG loads in December/January for the years 2023-2026 in PG&E's 1-in-35 EG forecast. These reductions change the Core/Noncore allocation percentages to 79 percent Core and 21 percent Noncore.[29] When Noncore curtailments are included, the Calpine's allocation percentages are 77.3 percent for Core and 22.7 percent for Noncore.[30]

TABLE 4-1
CALPINE'S APD CALCULATION COMPARED TO PG&E ALLOCATION
(MMcf/d)

Line No.	Metrics	Core	Noncore	Total
1	PG&E APD Allocation	3,041	1,570	4,611
2		66.0%	34.0%	100.0%
3	Industrial Backbone Adjustment	–	(6)	(6)
4	EG Backbone Adjustment	–	(746)	(746)
5	Calpine Adjusted Demand	3,041	818	3,859
6	Calpine Adjusted Allocation	78.8%	21.2%	100.0%
7	Curtailed Demand	–	76	–
8	Calpine Adj. Demand with Curtailment	3041	894	3,935
9	Calpine Adj. Allocation with Curtailment	*77.3%*	*22.7%*	*100.0%*

Note: Lines 3 and 4 reflects Calpine's proposed adjustments.
Lines 5-9 reflect allocations using Calpine's proposed adjustments.

Q 10 Why does Calpine make these adjustments?

A 10 Calpine makes these adjustments because it alleges that PG&E's APD proposal ignores the fact that a significant portion of PG&E's Noncore demand on an APD will be served directly from the backbone system, upstream of the local transmission system.[31]

Q 11 What is PG&E's response to Calpine's adjustments?

A 11 Calpine's adjustments are erroneous because APD forecast for local transmission already excludes Noncore backbone demand. Planners use

[28] Calpine Prepared Testimony, p. 19, Table 2.

[29] Calpine Prepared Testimony, p. 19, Table 2, footnote 35.

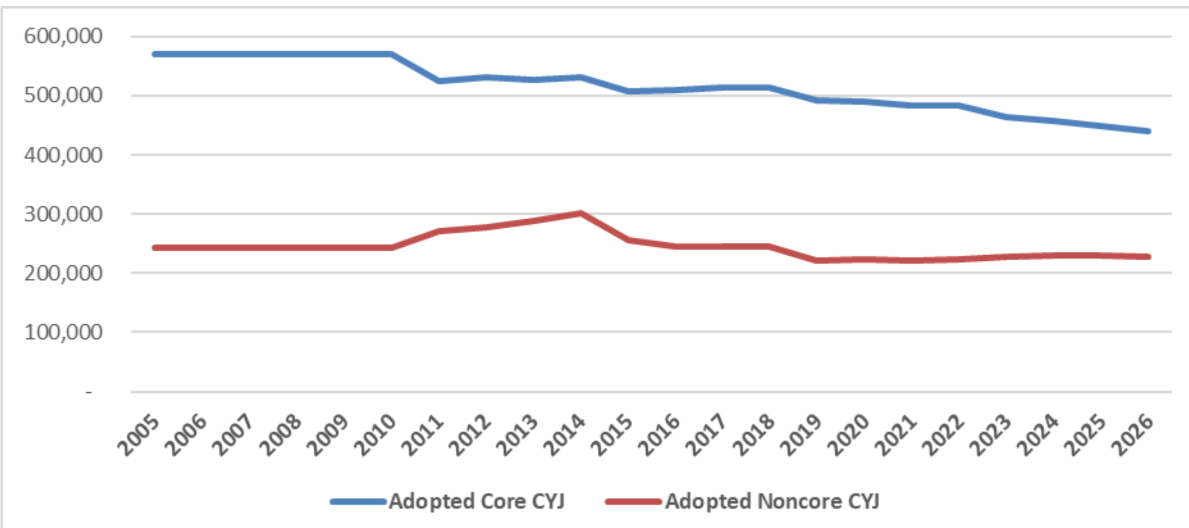
[30] Calpine Prepared Testimony, p. 19, line 7 to p. 20, line 13.

[31] Calpine Prepared Testimony, p. 17, line 1 to p. 18, line 9.

specific databases that identity customers that have historically taken their gas from the local transmission system. No backbone customers are included in these databases. Therefore, it is a mistake for Calpine to think that backbone customer volumes need to be removed from the local transmission volumes. Moreover, it is inconsistent for Calpine to subtract 1-in-35 years Noncore throughput forecast from 1-in-90 years demand forecast. Calpine also did not provide any workpapers showing analytical justification for the amount of curtailment they applied in their calculation.

Furthermore, Calpine's adjustments lead to artificially low allocation for Noncore customers. Figure 4-1 shows PG&E's historical approved throughputs and the resulting local transmission cost allocations.

FIGURE 4-1
ADOPTED AND PROPOSED THROUGHPUT ON LOCAL TRANSMISSION SYSTEM

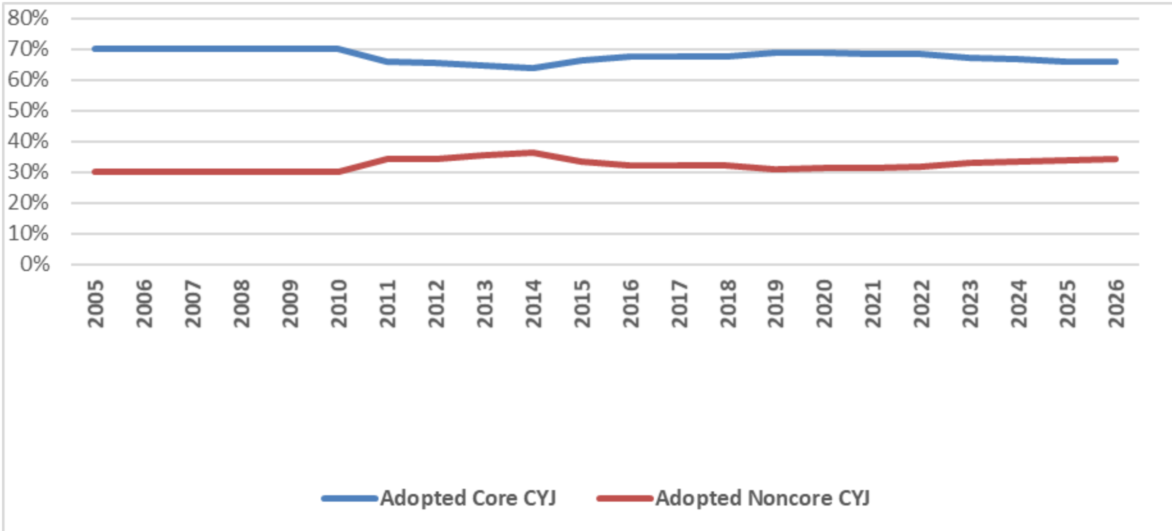


Note: "CYJ" is "Coldest Year January" and represents the coldest month, January, in the coldest year in 1 in 35 years.

As Figure 4-2 shows, the lowest Noncore allocation was 30 percent and occurred in 2003. Calpine's proposed Noncore allocation is also much lower than PG&E proposed acceptable range of 31 percent to 34 percent.[32]

32 PG&E Errata Testimony (Aug. 18, 2022), p. 4-37, Table 4-15, lines 3-7.

FIGURE 4-2
ADOPTED AND PROPOSED LOCAL TRANSMISSSION COST ALLOCATION PERCENTAGES



Note: "CYJ" is "Coldest Year January" and represents the coldest month, January, in the coldest year in 1 in 35 years.

Q 12 What is PG&E's response to Calpine's criticisms regarding the APD forecast including EG backbone?

A 12 Calpine's assumption that PG&E includes EG backbone demand in its PG&E's APD forecast is based on PG&E response to a Calpine's data request. Calpine's data request asked:

> What amount of EG APD demand that takes local transmission service, and how much EG demand on the APD takes backbone-only service from PG&E.[33]

PG&E answered:

> Backbone pipelines employ a different planning methodology than local transmission systems. As such, there is no APD load for backbone EG customers.[34]

Due to PG&E's response, Calpine assumed PG&E's APD forecast does not recognize that a portion of the Noncore demand on an APD that will not use the local transmission system.

33 PG&E Response to _Calpine Data Request_001-Q011, Part d, dated 3/4/22, in Attachment A at the end of this chapter.

34 PG&E Response to _Calpine Data Request_001-Q011, Part d, dated 3/4/22, in Attachment A at the end of this chapter.

To clarify, PG&E is stating that the APD forecast only calculates APD demands for customers who are served from the local transmission, and therefore, the APD forecast does not include any backbone customers. Since the design standard for backbone is 1-in-10 years and the APD forecast does not include any backbone customers, the EG backbone demand under APD condition is not calculated. Contrary to Calpine's mistaken interpretation, PG&E is not saying that it assumes there is no EG demand on the backbone.

Q 13 What is PG&E's conclusion regarding Calpine's comments on PG&E's local transmission cost allocation?

A 13 PG&E respectively requests that the Commission find PG&E's proposed local transmission methodology to be reasonable as is without Calpine's proposed adjustments to APD Noncore demands.

2. Indicated Shippers Adjustments Should Be Rejected as Based on Misunderstood Information.

Q 14 What is Indicated Shippers' position regarding PG&E's proposal to use APD as its methodology for local transmission cost allocation?

A 14 Indicated Shippers supports using the APD method because it is "an appropriate cost allocation for PG&E's [local transmission costs.]"[35] Indicated Shippers states APD reflects how the system is designed and how costs are incurred by PG&E.[36] However, like Calpine, Indicated Shippers has adjustments. Using information in the 2020 California Gas Report, Indicated Shippers reduces the total system demand from 4.61 Bcf to 4.07 Bcf,[37] which leads to a reduced noncore demand. As demonstrated in Table 4-2 below, the combination of these factors leads to Indicated Shippers' proposed 75 percent allocation to Core and 25 percent allocation to Noncore.[38]

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35 IS-1, p. 4-8, lines 19-20.

36 IS-1, p. 4-11, lines 3-4.

37 IS-1, p. 4-11, lines 23-25.

38 *Id.* p. 4-11 to p. 4-14.

TABLE 4-2
COMPARISON OF PG&E'S APD WITH INDICATED SHIPPERS' APD ADJUSTMENT
(Bcf)

Line No.	Metrics	Total	Noncore	Core
1	PG&E APD Allocation[(a)]	4.61	1.57	3.04
2			34%	66%
3	Indicated Shippers adjustment to total	4.07[(b)]	(0.54)	
4	system and Noncore demand			
5	Indicated Shippers APD Allocation	4.07	1.03	3.04
6			*25%*	*75%*

(a) PG&E Prepared testimony, Ch. 4,Table 4-1, p. 4-3.
(b) Indicated Shippers references 4.07 Bcf from the 2020 California Gas Report, Table 21, p. 84.

[Witness: J. Chen]

Q 15 What is PG&E's response to Indicated Shippers' adjustments and resulting allocation?

A 15 Indicated Shippers' adjustment should be rejected because it mixed volumetric information from two different design scenarios, APD and the Reliability Standard. This leads to unreasonable allocations for core and non-core.

APD is a 1-in-90-year standard, and the Reliability Standard is a 1-in-10-year standard. The purpose of such standards is so PG&E can meet various demand scenarios which serve different needs.

Indicated Shippers' adjustment mixes supply and demand data from the California Gas Report's "Forecast of Core Gas Demand and Supply on An APD" table from two different reports. Indicted Shippers have also used data from two different design standards, APD and Reliability, as discussed below. Indicated Shippers have made erroneous assumptions about the use of data from the California Gas Reports concerning backbone and local transmission system when they mixed the data for the two standards as described below.

First, Line No. 4 from the "Forecast of Core Gas Demand and Supply on An APD" table in the California Gas Report are two different backbone values based on opposing methodologies. Line No. 4 in the 2020 California Gas Report represents the minimum supply on the backbone needed to meet demand, while the 2022 California Gas Report value represents the total forecasted backbone capacity available. In table 21 of the 2020 California Gas Report, Line No. 4, or the "Total Resources to Meet Demand", denotes the minimum backbone capacity required to meet the Reliability Standard. This value of 4,067 MMcf/d (or 4.07 Bcf)[39] was derived from the summation of demands in Table 1, Section 5.3 of the 2019 GT&S Rate Case, and as ordered in Ordering Paragraph (OP) 7.[40] In contrast, Line No. 4 Table 19 of the 2022 California Gas Report, the "Projected Resources to Meet Demand" value of 4,232 MMcf/d represents the forecasted PG&E physical capacity that is available on the system and is sufficient to meet the minimum capacity requirement of 4.07 Bcf. See Table 4-3 for a comparison.

TABLE 4-3
COMPARISON OF DATA 2020 V. 2022 CALIFORNIA GAS REPORTS

Line No.		2020 California Gas Report Table 21 Line No. 4	2022 California Gas Report Table 19 Line No.4
1	Label for Line No. 4	Total Resources to Meet Demand	Projected Resources to Meet Demand
2	Description	Minimum supply needed on the backbone to meet demand	Total forecasted backbone capacity available
3	Standard[a]	1-in-10-year Reliability Standard	1-in-10-year Reliability Standard
4	Value	4,067 MMcf/d	4,232 MMcf/d

(a) PG&E's APD standard used for local transmission cost allocation is a 1-in-90-year design standard.

Second, the values in both the 2020 and 2022 California Gas Reports were determined based on the Reliability Standard, which is a 1-in-10-year design scenario and not a 1-in-90-year design scenario such as APD.

PG&E understands how the difference in the Reliability Standard and APD could have been misconstrued in the 2020 California Gas Report;

39 2020 California Gas Report, p. 84, Table 21.

40 D.19-09-025, p. 321, OP 7.

therefore, PG&E updated note four on Table 19 of the 2022 California Gas Report:

> Projected Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. This number is (the Reliability Standard) designed for a 1-in-10 design scenario while an APD is a 1-in-90 design scenario, meaning this number may not be representative of what the actual supply on a 1-in-90 day will be, but is sufficient to meet all APD Core demand.[41]

Third, Indicated Shippers erroneously subtracts the 3.04 Bcf of APD Core demand from the California Gas Report's 1-in-10-year backbone flowing supply of 4.07 Bcf.[42] This adjustment is incorrect because it mixes the inputs from two different design scenarios, as described above. By subtracting the 3.04 Bcf APD Core demand from the 4.07 Bcf minimum capacity for the Reliability Standard, Indicated Shippers is making erroneous assumptions about hydraulic modeling relationships on the backbone and the twelve the local transmission systems.

Q 16 What is PG&E's response to Indicated Shippers summing the total APD demand on the Local Transmission System to correlate with an APD scenario on the Backbone Transmission System?

A 16 By trying to combine the two design scenarios, Indicated Shippers assumes that an APD event will happen simultaneously on all 12 LT systems. This is an overly simplistic and incorrect assumption.

There are multiple steps used in the APD local transmission allocation model:

- APD incorporates 12 separate local transmission systems spread across the PG&E service territory from Humboldt County in the North to San Bernadino County in the South.
- Within these 12 separate local transmission systems, independent APD temperatures are developed from 32 weather stations across the service territory. An APD temperature for each of the 32 weather stations are

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41 2022 California Gas Report, p. 98, Table 19, Note 4.

42 IS-1, p. I-2, lines 38-40 and p. 4-13, lines 20-22.

calculated independently with a 1-in-90-year interval. The individual hydraulic models used for the allocation are assigned at least one weather station to develop APD loading for temperature dependent customers.

- Each model is loaded and analyzed with coincidental APD demand within the local transmission system being analyzed.

Accordingly, PG&E's APD local transmission allocation methodology is significantly more complicated than described by Indicated Shippers.

Indicated Shippers assumes APD events on the backbone and local transmission systems would require all 12 separate local transmission systems to experience APD conditions simultaneously. Historically, cold weather events cascade over several days, with the coldest temperatures moving from one region to the next—affecting different systems with varying severity each day. However, PG&E notes the probability of such a condition exceeds the 1-in-90-year APD criteria and does not accurately represent local transmission demand during an APD event.

Q 17 What is PG&E's overall conclusion regarding Indicated Shippers' comments on PG&E's local transmission cost allocation?

A 17 PG&E respectfully requests the Commission reject Indicated Shippers adjustments to the total local transmission and Noncore demands for the reasons stated above. PG&E developed the proposed APD allocation methodology as it reflects the current local transmission capacity investment process, as well as annual curtailment allocation for local transmission noncore customers. The local transmission allocation percentages for Core and Noncore customers were derived from the same 12 models used for capacity investments and developing annual Noncore curtailment levels using the same planning methods and assumptions.

3. The Commission Should Reject TURN's Criticisms and Average and Peak Demand Methodology.

[Witness: A. Taylor/J. Chen]

Q 18 What is TURN's position regarding PG&E's local transmission cost allocation proposal?

A 18 TURN has three criticisms with PG&E's APD: APD is too extreme,[43] APD forecast is unreliable,[44] and PG&E wrongly relies on data significantly impacted by the COVID-19 pandemic.[45] TURN also states that the CYPM method is not a viable choice for allocating local transmission cost.[46] TURN proposed the Average and Peak Demand method for allocating local transmission cost.[47] PG&E discusses these below.

a. TURN's Criticism That the APD Is Too Extreme Should Be Rejected Because PG&E 1-in-90 Year Local Transmission Design Standard Has Been Approved by the Commission.

Q 19 Please summarize TURN's comments.

A 19 TURN states the APD is a "very extreme allocation method" because an extreme event impacting all 12 PG&E's LT systems at the same time has never occurred.[48]

Q 20 What is PG&E's response to TURN's criticism that the APD design standard is too extreme?

A 20 PG&E disagrees with TURN's criticism that the APD design standard is too extreme. In D.22-07-002, the Commission rejected its Staff recommendation to eliminate all current infrastructure design standards and replace them with a 1-in-10-year peak day design standard for both PG&E and SoCalGas, and therefore, upheld PG&E's 1-in-90-year design standard.[49] The Commission also stated that the current reliability standards do not overstate the capacity that gas utilities must maintain.[50]

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43 TURN Prepared Testimony, p. 15, lines 4-8.

44 TURN Prepared Testimony, p. 17, lines 15-21.

45 TURN Prepared Testimony, p. 21, lines 4-14.

46 TURN Prepared Testimony, p. 24, lines 1-12.

47 TURN Prepared Testimony, p. 26, lines 4-23.

48 TURN Prepared Testimony, p. 15, lines 4-8.

49 D.22-07-002, p. 26.

50 D.22-07-002, p. 27.

Q 21 TURN discusses PG&E's Response to a TURN data request, stating that PG&E admits that Noncore curtailments will become even more unlikely than they have already been.[51] Can you explain?

A 21 The APD forecasts rely on the local transmission annual curtailment plan for Noncore customers. PG&E cannot accurately predict long-term weather anomalies and their frequency; therefore, an APD forecast is prudent for the safe and reliable operation of PG&E's system. Furthermore, in the case of an APD event occurring in the period used for analysis, forecasted 92 percent of Noncore demand will be served and 8 percent will be curtailed.[52] Consequently, PG&E believes that subsequent APD forecast should reflect the real possibility of curtailments during an APD event.

Q 22 What is PG&E's response to TURN's allegation that it is "no longer the case that peak day demand are causing significant new investments in the PG&E system?"[53]

A 22 The Commission has continually upheld using coincidental peak allocation methodologies to allocate local transmission cost for all utilities.[54] Moreover, contrary to TURN's claim, new investments are in fact being made due to peak day demand, significant or not for this rate case period.

b. The Commission Should Disregard TURN's Criticism That the APD Forecast Is Unreliable.

Q 23 Please explain why TURN alleges the APD forecast is unreliable.

A 23 TURN alleges the APD demand forecast is unreliable because it contains several inaccuracies:

- The regression models used in the APD forecast does not account for the "bend back" phenomenon where gas usage is capped at a maximum value no matter how low the temperature decreases once heating equipment reaches its full capacity.[55]

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51 TURN Prepared Testimony, p. 16, line 10 to p. 17, line 2.

52 PG&E Errata Testimony (Aug. 18, 2022), p. 4-28, lines 13-14.

53 TURN Prepared Testimony, p. 17, lines 3-4.

54 D.19-09-025, pp. 256-266; D.22-07-002, p. 51, OPs 7-8; and, PG&E Errata Testimony (Aug. 18, 2022), p. 4-6, Table 4-3, lines 2-4.

55 TURN Prepared Testimony, p. 17, line 16 to p. 18, line 3.

- It is not transparent.
- The APD forecast demands are suspect because of changes that occur as part of the APD forecast normal planning procedures.[56]

PG&E disagrees with these criticisms as described below.

Q 24 What is PG&E's response to TURN's criticism that the APD forecast does not account for a "bendback phenomenon"?

A 24 PG&E disagrees with TURN's analysis regarding a "bendback phenomenon" because: (1) TURN did not present any supporting evidence or analysis about the "bendback" phenomenon and the APD forecast, and (2) PG&E's is not aware of any circumstances where such a phenomenon exists. As of the date of this rebuttal, PG&E has not observed any bendback behavior for PG&E's customers.

Furthermore, the "bendback" phenomenon requires that PG&E knows the maximum appliance load across the service territory at any given time. It would also require that every single customer will react in a universal matter. PG&E believes that every household has a different threshold for heating, be it physical or financial, and as temperature decreases, different points of demand are triggered.

Q 25 How does PG&E respond to TURN's criticism regarding PG&E's local transmission peak throughput has not been transparent[57] or is a "black box"[58] in this proceeding?

A 25 PG&E acknowledges the APD model is complex, but PG&E maintains that it is not a "black box." PG&E interprets a black box model as a system using input and outputs to create useful information, without any knowledge of its internal workings. Like other regulatory models, the APD forecast includes data inputs that contain millions of records and must be processed through a database. All the calculations in the database are accessible but are written in programming language. For example, APD databases were queried to determine which areas and non-core customers were responsible for the decrease in the 2020-2021 APD Noncore demand.

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[56] *Id*. at p. 18, lines 18-21.

[57] TURN Prepared Testimony, p. 18, lines 4-6.

[58] TURN Prepared Testimony, p. 18, lines 13-17.

[Witness: A. Taylor]

Q 26 How does PG&E respond to TURN's criticism regarding PG&E's changes to its local transmission APD forecasts during this proceeding?[59]

A 26 Specific to the updates that were discussed in PG&E's Direct Testimony, Chapter 4, these changes were part of the APD forecast normal planning procedures so that forecast results are based on the most current information and planning assumptions.[60] Therefore, these updates add to the robustness and accuracy of the most recent APD forecast and are not an impediment as TURN suggests.[61]

The data that PG&E used in the original September 2021 filing was from the preliminary forecast instead of data from the final February 2021 update. However, the forecast submitted in the original filing was only updated once in the May 2022 Errata.

Q 27 TURN states that:

> PG&E should either use a true 'forecast' that is prepared before the fact, or else rely entirely on a retrospective look at what has already happened...[62]

What is PG&E's response?

A 27 PG&E used the 2020-2021 APD forecast because this forecast was the most recent APD forecast available at the time of the original Cost Allocation and Rate Design (CARD) filing. PG&E also believes that using APD forecasts from multiple years to allocate local transmission cost may be a reasonable approach in subsequent GT&S allocation and rate design cases.

For illustration purposes only, I will describe TURN's process. TURN recommended using the most recent APD forecast from the past five years to local transmission cost if the Commission approves the APD methodology. TURN recommended using the 2020-21 APD forecast from PG&E's original September 2021 CARD filing to calculate a 5-year average instead of using the updated 2020-21 APD forecast from August. Table 4-4 below shows the Core and Noncore demands from the five most recent APD

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59 TURN Prepared Testimony, p. 18, lines 18-23.

60 See PG&E Errata Testimony (Aug. 18, 2022), Chapter 4, p. 4-30, lines 6-10.

61 TURN Prepared Testimony, p. 18, lines 18-23.

62 TURN Prepared Testimony, p. 20, line 30 to p. 21, line 3.

forecasts. Line 7 shows, the five years average APD forecasted demands and the resulting Core and Noncore average allocation percentages which are based on the 2020-21 APD forecast from the May Errata filing. Line 8 shows TURN's recommendation which uses the 2020-21 APD forecast from the original September 2021 CARD filing. According to PG&E calculations both approaches result in similar allocation percentages for local transmission cost, approximately 64 percent for Core and 36 percent for Noncore. However, TURN states in its opening testimony that their 5-Year Average APD calculation results in a 36.74 percent allocation for Noncore and a 63.26 percent for Core.

TABLE 4-4
APD HISTORICAL WINTER DEMANDS

Line No.	APD Winter Season	Core Total Demand (Mcf/d)	Noncore Total Demand (Mcf/d)	Noncore Allowable (Mcf/d)	Noncore Curtailed Demand (Mcf/d)	Core Total Demand %	Noncore Total Demand %	Noncore Curtailed Demand %
1	2021-22	3,002,011	1,778,192	1,598,434	179,758	65.25%	34.75%	10.11%
2	Updated 2020-21[(a)]	3,040,495	1,715,394	1,569,913	145,481	65.95%	34.05%	8.48%
3	Original 2020-21[(b)]	3,013,935	1,950,380	1,794,795	155,585	62.68%	37.32%	7.98%
4	2019-20	3,037,393	2,213,153	2,027,315	185,838	59.97%	40.03%	8.40%
5	2018-19	2,976,982	2,010,538	1,833,736	176,802	61.88%	38.12%	8.79%
6	2017-18	3,145,866	1,621,713	1,402,870	218,843	69.16%	30.84%	13.49%
7	Updated 2020-21[(a)]	*3,040,549*	*1,867,798*	*1,686,454*	*181,344*	64.44%	35.56%	9.86%
8	Original 2020-21[(b)]	*3,035,237*	*1,914,795*	*1,731,430*	*183,365*	63.79%	36.21%	9.75%

(a) From PG&E's Errata Testimony (August 18, 2022), p. 4-3 Table 4-1.

(b) From PG&E's original Prepared Testimony (September 30, 2021), p. 4.2 Table 4-1.

c. PG&E Agrees That the Period Chosen for the APD Analysis Was Significantly Impacted by the COVID-19 Pandemic.[63]

Q 28 TURN states that PG&E's APD forecast wrongly relies on data that was significantly impacted by the COVID-19 pandemic.[64] What is PG&E's response?

A 28 PG&E does agree that the 2020-2021 Winter season was deeply impacted by the COVID-19 pandemic; however, PG&E does not believe that effects of the pandemic should have been ignored. As stated above, the main

63 TURN Prepared Testimony, p. 21, lines 4-5.

64 TURN Prepared Testimony, p. 21, lines 6-11.

purpose for the APD forecast is to determine gas capacity needs for Core customers and to generate the Noncore demand that can be served under APD conditions. Therefore, the APD forecast should try to accurately account for all major factors that might contribute to changes in capacity requirements. Because the pandemic resulted in less forecasted demand for Noncore customer, capacity requirements should have decreased on the local transmission system. However, as stated above, PG&E believes that using APD forecasts from multiple years to allocate local transmission cost may be reasonable approach in subsequent GT&S allocation and rate design cases.

Q 29 Does PG&E agree with TURN that the APD seem to vary considerably from year-to-year?[65]

A 29 PG&E believes the APD demand can moderately vary from year to year as Table 4-4 shows. However, as stated above, PG&E believes that using APD forecasts from multiple years to allocate local transmission cost may be reasonable approach in subsequent GT&S allocation and rate design cases.

d. While PG&E Did Not Propose Cold Year Peak Month, It Remains a Viable Alternative.

Q 30 TURN briefly examines CYPM as an alternative but state that the results from the APD and the CYPM models are anomalous.[66] What is PG&E's response?

A 30 PG&E disagrees with TURN's position. First let me provide background. The APD forecast uses a temperature assumption of the coldest day in 1-in-90-year while the CYPM forecast uses the coldest month in a 1-in-35-year cold year event. Core customer demand is mostly temperature dependent, that is, lower temperatures increase Core demand. However, Noncore demand is not as temperature dependent.

TURN believes the Core allocation percentage based on the APD forecast, which is based on a relatively extreme temperature scenario, should be higher than Core allocation percentage based on the CYPM

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65 TURN Prepared Testimony, p. 22, lines 27-28.

66 TURN Prepared Testimony, pp. 24-25.

forecast.[67] However, the APD forecast results in a 65.95 percent allocation for Core while the CYPM forecast results in a 66.29 percent allocation for Core. These results contradict TURN's expectations; therefore, TURN consider the results anomalous.[68]

Q 31 Are the results from APD and CYPM models "anomalous"?

A 31 No, the APD and CYPM results are not anomalous. APD's extreme temperature scenario is not supposed to necessarily provide higher Core allocation because the allocation depends on the proportion of usage which may remain fairly close even if temperature scenarios are changed. APD method, when compared to CYPM, uses different approaches, assumptions, data sources, and time periods. In addition, APD forecast uses hydraulic models to determine the capacity needs for the local transmission system. The CYPM forecast is based on the Chapters 2A and 2B throughput forecasts. Chapter 2A EG throughput forecast is based on the PLEXOS production cost model and historical throughput.[69] Chapter 2B Non-EG forecast uses econometric models.[70] Moreover, the APD allocation results are based on the 2020-2021 APD forecast and the CYPM allocation results are based on the average of 2023-2026 forecast period.

e. The Commission Should Reject the Average and Peak Demand Method Because This Method Does Not Align With Cost Causation Principles.

Q 32 TURN now proposes to use the Average and Peak Demand method for PG&E's local transmission cost allocation? What is PG&E's response?

A 32 PG&E disagrees with TURN's proposal. TURN provided limited and incomplete analysis. Therefore PG&E attempted to but was unable to recreate TURN's analysis.

However, I will first summarize TURN's proposal before providing additional explanation in the subsequent answers. TURN believes using an "Average Usage and Peak Demand Method" is an option that is a

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67 TURN Prepared Testimony, p. 24, lines 8-12.

68 TURN Prepared Testimony, p. 24, line 2 to p. 25, line 8.

69 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-3, line 3 to p. 2A-4, line 3.

70 PG&E Errata Testimony (Aug. 18, 2022), p. 2B-2, line 10 to p. 2B-3, line 4.

compromise between the allocation of backbone transmission costs and distribution costs.[71]

PG&E notes that during the workshops, TURN recommended using the APD methodology that used illustrative data. TURN's APD method resulted in a cost allocation of 60 percent Core and 40 percent Noncore.[72] TURN did not present or recommend an Average and Peak Demand method during any of the workshops. As part of PG&E's analysis of TURN's August 2020 APD methodology, PG&E described TURN's methodology and showed how TURN's APD allocation percentages were calculated.[73] PG&E also updated TURN's methodology, using the 2020-2021 APD demands, which resulting in a 67 percent allocation for Core and a 33 percent allocation for Noncore.[74] PG&E's proposed APD methodology allocates 66 percent to Core and 34 percent to Noncore.[75]

TURN now supports the Average and Peak Demand because this method is one of the methods that is used by other national utilities, and it reflects a compromise between other commonly used methods. TURN finds flaws in the APD method, and therefore, likes that the Average and Peak Demand method does not place completely rely on the APD forecasts.[76] The Average and Peak method is a two-part allocation method where the first allocation is based on cost due to the average usage. The second allocation is based on the cost related to peak demand. The percentage of cost allocated based on the average usage is determined by the load factor. The load factor is the average load divided by the peak load. The remaining cost is allocated based on coincident peak demand.[77]

It appears that TURN calculates the Average and Peak Demand method from two different models. Table 4-5 shows the values used in TURN's example. TURN uses the 2019-2020 APD total local transmission demand

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71 TURN Prepared Testimony, p. 26, lines 4-5.

72 PG&E Errata Testimony (Aug. 18, 2022), p. 4-20, lines 2-15, p. 4-23, lines 1-2.

73 PG&E Errata Testimony (Aug. 18, 2022), p. 4-21, line 29 to 4-24, line 4.

74 PG&E Errata Testimony (Aug. 18, 2022), p. 4-28, lines 7-19, p. 4-30, Table 4-10.

75 PG&E Errata Testimony (Aug. 18, 2022), p. 4-30, Table 4-10.

76 TURN Prepared Testimony, p. 26, lines 24-29.

77 TURN Prepared Testimony, p. 26, lines 18-19.

to represent the peak usage while the average usage comes from inputs for CYPM in PG&E's Prepared Workpapers for Chapter 6, Workpaper 5 "Local Transmission Workpaper." TURN divides the average usage, line 3, by the peak usage, line 1, to get a loading factor of 26 percent. Since the local transmission is $1.4 billion, $375 million will be allocated using the average usage and rest of the revenue requirement will be allocated using peak usage. TURN's average usage allocation percentages are derived from PG&E's Prepared Local Transmission Workpapers for Chapter 6 2023-2026 average forecasted throughput for local transmission. The peak usage allocation percentages are derived from the 5-year average APD local transmission forecast shown in Table 4-5, line 8.

TABLE 4-5
TURN'S AVERAGE AND PEAK DEMAND CALCULATIONS

Line No.	Metric	Value	TURN's Stated Data Source
1	Peak Usage (MDth)	5,300	2019-2020 APD Forecast
2	Average Yearly Usage (MDth)	507,745	Chapter 6: Workpaper 5 out of 10 Local Transmission Workpaper[(a)]
3	Average Daily Usage (MDth)	1,391	Chapter 6: Workpaper 5 out of 10 Local Transmission Workpaper[(a)]
4	Load Factor	26.2%	Calculation: line 3 divided by line 1
5	LT Revenue Requirement	$1,427,773,000	2023 GRC Phase I
6	Cost to be allocated by customer class average usage	$374,745,206	Calculation: (line 4) * (line 5)
7	Cost to be allocated by customer class peak usage	$1,053,027,794	Calculation: line 5 minus line 6
8	Average Core Allocation	49.57%	Chapter 6: Workpaper 5 out of 10 Local Transmission Workpaper[(a)]
9	Average Noncore Allocation	50.43%	Chapter 6: Workpaper 5 out of 10 Local Transmission Workpaper[(a)]
10	Peak Core Allocation	63.26%	5-Year Average APD forecast
11	Peak Noncore Allocation	36.74%	5-Year Average APD forecast
12	TURN Core Allocation	60%	Calculation: See Equation 1
13	TURN Noncore Allocation	40%	Calculation: 100 percent minus line 12

(a) PG&E is unable to tie TURN's numbers to PG&E's submitted testimony and workpapers in TURN's stated data source. However, if PG&E relies on TURN's representation, these numbers appear to be inputs for CYPM, which is a different model and time range.

Referencing numbers from Table 4-5, the equation below shows how the Core Average and Peak Demand allocation percentage was calculated.[78]

[78] TURN Prepared Testimony, pp. 27-28.

FIGURE 4-3
EQUATION 1 – CORE'S AVERAGE AND PEAK DEMAND ALLOCATION

(Load Factor) X (Average Core Allocation) + (1 - Load Factor) X (Peak Core Allocation) = Core Average and Peak Demand

$$0.262 \times 0.4957 + (1 - 0.262) \times 0.6326 = 0.5967$$

Q 33 What is PG&E's response to TURN's Average and Peak Demand calculations?

A 33 TURN's calculation in the equation is erroneous because it appears they mixed data sources and models as reflected Table 4-5:

- For calculating the average and peak allocation percentages, TURN used APD data and CYPM inputs. The 1-in-90 year APD and 1-in-35 year CYPM models use two different weather scenarios and forecast demand during two different periods.
- The average allocation percentages were from the 2023-2026 CYPM forecast while the peak allocation percentages were from APD average 5-year forecast, years 2018-2022.
- In addition, in TURN's response to PG&E's data request, observed TURN's calculations in their workpapers are difficult to decipher and did not include additional detail like formulas or labels describing numbers used in the calculations. See Attachment B for TURN's response to PG&E's data request No. 2. With TURN's limited analysis, PG&E attempted to recreate TURN's calculations but was unable to match TURN's results.

Q 34 Does PG&E agree with using the Average and Peak Demand method to allocate local transmission cost?

A 34 No, PG&E does not agree with using the Average and Peak Demand method for the following reasons: TURN's calculations were erroneous as described above, Average Peak and Demand is not a coincidental peak allocation methodology, it does not align with cost causation principles and TURN did not present it at the workshop.

TURN's Average and Peak Demand is not a coincidental peak allocation methodology. The Commission has continually upheld using coincidental peak allocation methodologies to allocate local transmission cost for all utilities.[79] As the results from Black & Veatch and Indicated Shippers surveys discussed in Chapter 4 show, coincidental peak allocation methodologies are also the most common method used among the utilities surveyed.[80] Coincidental peak allocation methodologies are more aligned with cost causation principles because they allocate more cost to customers with low load factors. Coincidental peak allocation methodologies favor high load factor customers with a relatively constant usage throughout the year, and therefore, their load is more spread out. A greater percentage of cost is assigned to lower load factor heating customers, generally Core customers, whose consumptions is greatest in winter.[81] On the other hand, the Average and Peak Demand method moderates the cost between high and low factor customers resulting in artificial low allocation for Core customers. Therefore, Average and Peak Demand does not align with cost causation principles.

Finally, choosing the Average and Peak Demand method for allocating local transmission costs was not an option to choose from. Pursuant to Commission direction, PG&E had to choose one of the methodologies presented by the other parties at the workshops.[82] TURN did not present Average and Peak Demand at any of the workshops. None of the parties presenting recommended the Average and Peak Demand method.

Therefore, Average and Peak Demand was never an option that PG&E could select and remain compliant with Commission directive.

f. Summary of PG&E's Conclusion for TURN's Positions.

Q 35 Please summarize your recommendation regarding how the Commission should resolve these issues.

A 35 PG&E respectively requests that the Commission find PG&E's proposed local transmission methodology to be reasonable and reject TURN's proposed methodology, Average and Peak Demand method, in addition to, TURN's proposed allocation percentages. PG&E also believes it may be

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79 D.19-09-025, pp. 256-266; D.22-07-002, p. 51, OP 7-8.

80 PG&E Errata Testimony (Aug. 18, 2022), p. 4-17, lines 15-19, p. 4-21, lines 24-28.

81 PG&E Errata Testimony (Aug. 18, 2022), p. 4-18, Figure 4-3.

82 *Id.* at p. 4-1, lines 20-22.

reasonable to use an average multi-year APD forecast to allocate local transmission cost in subsequent GT&S allocation and rate design cases.

4. SBUA's Local Transmission Allocation percentages Should Be Rejected Because the percentages Are Based on Erroneous Data.

Q 36 What local transmission allocation percentages does SBUA recommend?

A 36 SBUA rejects PG&E's proposed allocation percentages of 66 percent for Core and 34 percent for Noncore but supports TURN's allocation percentages, 60 percent Core and 40 percent Noncore. SBUA believes PG&E's cost allocation methodology appears to improperly and unnecessarily allocate costs to Core Customers.[83]

Q 37 Did SBUA provide any analysis to support their position?

A 37 No, SBUA relied on the analysis presented by TURN at the August 2020 workshop, as summarized in PG&E's Prepared Testimony, Table 4-7.[84] SBUA's witness admits that he "is not an expert on TURN's proposal, but the allocation methodology used by TURN appears to better allocate costs between core and non-core customers."[85] However, as described in PG&E's Prepared Testimony, PG&E updated TURN's August 2020 APD methodology, using the 2020-2021 APD demands, which resulted in a 67 percent allocation for Core and a 33 percent allocation for Noncore.[86]

Q 38 Please summarize your recommendation regarding how the Commission should resolve this issue.

A 38 Since SBUA is relying upon TURN's August 2020 APD methodology without the updated calculations, PG&E respectively requests that the Commission reject SBUA proposed local transmission allocation percentages.

5. NCGC's Recommendations Using the Cold Year Peak Month Method for Local Transmission.

Q 39 Please describe NCGC's position on local transmission cost allocation.

A 39 NCGC supports the current approved methodology, CYPM for allocation local transmission cost, since NCGC believes PG&E did not provide a

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83 SBUA Direct Testimony, pp. 12-13.

84 SBUA Direct Testimony, p. 13.

85 SBUA Direct Testimony, p. 12-13.

86 PG&E Errata Testimony (Aug. 18, 2022), p. 4-28, line 18 to p. 4-30, line 26.

meaningful rational for changing the local transmission methodology. They believe that changing methodologies will not change the allocation percentages by a significant amount. NCGC believes it makes little sense now to change the methodology when such factors as changing customer mix and usage trends will ultimately lead to reduce gas usage.[87]

Q 40 What was PG&E's motivation for choosing the APD method for allocating local transmission cost?

A 40 See PG&E's response to Question 8. PG&E chose the APD method for allocation local transmission costs because the method was recommended during the workshop, it aligns with principle of cost causation and, is one of the most common methods for allocating local transmission cost. To comply with the 2019 GT&S Decision, D.19-09-025, PG&E had to propose a nationally used method proposed at the ordered workshops.[88] There were only two recommended methodologies that fulfilled these requirements, the APD and the CYPM methodologies.

While PG&E chose the APD method over the CYPM, PG&E deems both models acceptable for allocating local transmission cost because both were recommended at the workshop and were methods used by other national utilities. However, the Black & Veatch and Indicated Shippers surveys presented at the workshop showed that over 16 utilities included in the surveys used a coincident peak design day method such as the APD method, while only a few utilities used coincident peak month to allocate these costs. In addition, the APD method is used to determine gas capacity requirements for Core customers; however, the CYPM method is not. The CYPM forecast is derived from the gas throughput forecast which is updated every few years. A new local transmission capacity plan and APD forecast are developed for each Winter season. These yearly APD forecasts could be very advantageous when gas trends are changing so rapidly.[89]

Q 41 Please summarize your recommendation regarding how the Commission should resolve this issue.

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87 NCGC-1, p. 18, lines 17-24.

88 PG&E Errata Testimony (Aug. 18, 2022), p. 4-1, lines 6-27.

89 *Id.* at p. 4-38, lines 17-32.

A 41 PG&E respectively requests that the Commission find PG&E’s proposed local transmission methodology to be reasonable.

D. Conclusion

Q 42 Does this conclude your rebuttal testimony?

A 42 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

PG&E'S RESPONSE TO CALPINE SET ONE,

QUESTION 11 (3/4/22) AND REVISED RESPONSE 11E (6/27/22)

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_001-Q011		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_001-Q011		
Request Date:	January 24, 2022	Requester DR No.:	001
Date Sent:	March 4, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	Annette Taylor	Requester:	Joseph M. Karp

This data request refers to the direct testimony that PG&E served in this proceeding on September 30, 2021.

Local Transmission

QUESTION 011

This question concerns PG&E Abnormal Peak Day (APD) forecast, which Calpine understands PG&E is revising due to data issues.

a. Please provide the APD demand forecast, by customer class, which results in the 63% core/37% noncore cost allocation proposed by PG&E.

b. Please quantify how much noncore industrial and noncore EG throughput is curtailed in the APD forecast.

c. Please describe how the EG throughput forecast on the APD is calculated.

d. Please include, for EG, the amount of APD demand that takes local transmission service, and how much EG demand on the APD takes backbone-only service from PG&E.

e. Please provide an explanation of the errors in the APD forecast and the changes that PG&E plans to make. Please provide the revised testimony/workpapers based on these changes, when available.

ANSWER 011

11.a

The APD demand forecast by customer class that results in the 63%/37% allocation is not available since the underlying data has been overwritten with the revised APD forecast. (Please see Answer 11e) Therefore, this response uses the most current data available – winter 2021-2022.

The local transmission APD load components for the winter of 2021-2022 are: Core Residential – 2,145,887 Mcfd, Core Commercial – 856,124 Mcfd, and Noncore All – 1,778,192 Mcfd.

11.b

The projected APD non-core curtailment volume for the 2021-2022 winter is 179,758 Mcfd. Separating non-core, local transmission EG demand is not easily attainable as the data source used for local transmission curtailment planning cannot accurately split noncore EG load from other noncore demand for all customers. For instance, some customers use some of their gas for EG and the balance for non-EG purposes (refineries are a good example). This gas runs through the same meter and is somehow back-calculated in the billing process. The database that is used to retrieve this information cannot accurately split this usage, so the segregated EG demand would be under or overrepresented depending on the class assigned to that customer.

11.c

The following is a description of how the EG throughput forecast on the APD is calculated. PG&E uses a probabilistic loading methodology for all non-temperature dependent, noncore demand on the local transmission system. Customers are first assigned to a curtailment zone based on system hydraulics. An APD demand for each non-core customer (non-temperature dependent) is then developed from the load diversity process. If the potential magnitude of a noncore, non-temperature dependent customer's demand is high enough to risk the safety of a particular system, the demand is analyzed separately and an APD projection is subsequently developed.

11.d

Backbone pipelines employ a different planning methodology than local transmission systems. As such, there is no APD load for backbone EG customers. As stated above, separating non-core, local transmission EG demand is not easily attainable as the data source used for local transmission curtailment planning cannot accurately split noncore EG load other noncore demand for all customers.

11.e

The APD forecast was revised to incorporate more recently available data, and not because of errors in the prior forecast In responding to a discovery request, PG&E revised the 2020 – 2021 APD Winter forecast values that PG&E filed for the CARD proceeding. The original 2020-2021 Winter forecast that was served with PG&E's direct testimony, Chapter 4, on September 30, 2021 came from information created in Nov 2020 for the upcoming 2020-2021 Winter season. As part of the Gas System Planning Engineering team's winter planning process, the design day estimates (APD, CWD) for large customers are reviewed immediately prior to the upcoming winter. Several local transmission customers in the East Bay had their projected usage adjusted after the original filing. The usage also changed for other local transmission areas through this process, but the changes in the East Bay are overwhelmingly responsible for the difference between the original and revised forecast.

PACIFIC GAS AND ELECTRIC COMPANY
GTS – Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Response

PG&E Data Request No.:	Calpine_001-Q011		
PG&E File Name:	GTS-CARD-2023_DR_Calpine_001-Q011Rev01		
Request Date:	January 24, 2022	Requester DR No.:	001
Date Sent:	June 27, 2022	Requesting Party:	Calpine Corporation
PG&E Witness:	Annette Taylor	Requester:	Joseph M. Karp

Local Transmission

QUESTION 011

e. Please provide an explanation of the errors in the APD forecast and the changes that PG&E plans to make. Please provide the revised testimony/workpapers based on these changes, when available.

ANSWER 011 – REVISED 01

e. The PG&E proposed transmission allocation results are based on the 2020 – 2021 Winter APD forecast; however, the original 2020 – 2021 Winter APD forecast that was presented in the original 2023 GT&S CARD testimony that was filed in September 2021 did not represent the most recent forecasting estimates for the 2020 – 2021 Winter season, and therefore, was out of date. Consequently, because of this error, PG&E revised its proposed allocation results to be based on the most recent 2020 – 2021 Winter APD forecast. The revised Chapter 4 testimony which gives a detail account of the revision and the revised workpaper were included as part of the May 2022 revised 2023 GT&S CARD testimony. [1]

1 A.21-09-018, PG&E's 2023 Gas Transmission and Storage Cost Allocation and Rate Design Revised Testimony, Chapter 4, pp 30 - 31.
APD and CYPM Workpaper_Rev-01.xlsx.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT B

TURN AVERAGE AND PEAK DEMAND WORKPAPER FROM

MIKE FLORIO

LT load factor

Total LT Tput

2023	518,135 MDth
24	511,741
25	503,858
26	497,245
	2,030,979

2,030,979 ÷ 4 = 507,745

$\frac{1391}{5360} = 26.2\%$

÷ 4 = 507,745

÷ 365 = 1,391 MDth/d

C tput	NC tput	
260,334	257,802	2023
254,882	256,859	24
248,804	255,054	25
242,793	254,452	26
1,006,813	1,024,167	

1,006,813
+ 1,024,167
= 2,030,980

49.57%   50.43%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

REBUTTAL TESTIMONY OF

TODD PETERSON ON

THE ELECTRIC GENERATION

LOCAL TRANSMISSION RATE DESIGN ANALYTICS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
REBUTTAL TESTIMONY OF
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
REBUTTAL TESTIMONY OF
TODD PETERSON ON
THE ELECTRIC GENERATION
LOCAL TRANSMISSION RATE DESIGN ANALYTICS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Todd Peterson and I am a Principal Strategic Analyst. I am sponsoring PG&E Prepared Testimony, Chapter 5, EG-LT Rate Design Analytics. This testimony responds to the direct testimony of The Utility Reform Network (TURN)[1] and the Northern California Generation Coalition (NCGC).[2] Pacific Gas and Electric Company (PG&E) summarizes the parties' positions in Section B below.

B. Summary of Parties Positions and PG&E's Responses

Q 2 Please briefly summarize the parties' positions with regard to Chapter 5, LT Rate Design Analytics, and PG&E's response?

A 2 TURN and NCGC have concerns with the EG Analysis.

First, regarding TURN's recommendations:

1. TURN concludes that PG&E's analysis using PLEXOS production cost analysis is "solid,"[3] subject to two primary concerns. In its first primary concern, TURN claims that "PG&E is suggesting that other gas utilities might change their own EG rate designs in response to PG&E's changing its own. There is simply no reason to believe that would be the case."[4]

   PG&E's response: PG&E disagrees with TURN's first concern. It is appropriate for this analysis to consider rate design changes other utilities may contemplate in response to a PG&E's rate design change.

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[1] TURN Prepared Testimony, Ch. 2A.

[2] NCGC-1.

[3] TURN Prepared Testimony, p. 30, lines 1-3.

[4] *Id.* at p. 30, lines 21-23.

2. TURN's second concern regarding the production cost model is that the model analysis includes an incorrect assumption regarding sunk costs, stating that how "generators recover the sunk cost of the reservation charge should not be PG&E's concern… ."[5]

PG&E's response: PG&E disagrees with TURN that the assumption of the reservation charge to be a sunk cost should not be PG&E's concern.

3. TURN criticizes PG&E for improperly concluding "the evidence in support of a fixed/variable EG-LT rate design is 'inconclusive.'"[6]

PG&E's response: PG&E disagrees with TURN's critique that PG&E "wrongly concludes that the evidence in support of a fixed/variable EG-LT rate design is 'inconclusive.'"[7]

4. TURN criticizes PG&E's concerns that:

> [R]esults are not really conflicting at all, as the increased generation by EG-LT customers has to be matched by reduced generation from somewhere else.[8]

PG&E's response: PG&E disagrees. For the rate design analysis presented in Chapter 5 of its prepared testimony, it is conflicting for backbone generation to decrease while local generation increases.

5. TURN alleges:

> PG&E's 'historical analysis' is simply not a reliable approach to evaluating the impact of the change in EG-LT rate design.[9]

PG&E's response: PG&E disagrees with TURN that the Chapter 5 historical analysis is not a reliable approach to evaluating the impact of changing the EG-LT rate design.

Regarding concerns from NCGC relating to PG&E's LT Rate Design Analysis:

6. NCGC criticizes the Chapter 5 analytical results, saying that PG&E's analysis fails to accurately reflect the situation, because it does not show that maintaining the status quo (a volumetric rate) is better than

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5 *Id.* at p. 32, lines 9-12.

6 *Id.* at p. 29, lines 11-13.

7 *Id.* at p. 29, lines 11-13.

8 *Id.* at p. 32, lines 14-16.

9 *Id.* at p. 33, lines 1-2.

the change requested by customers (a variable rate with a fixed charge component).[10]

PG&E's response: PG&E disagrees with NCGC's statement that the EG-LT rate analysis fails to accurately reflects the situation. The analysis appropriately arrived at a conclusion stated in PG&E's Prepared Testimony:

> The G-EG LT rate design analytics results point towards a potential increase in the net EG gas throughput assuming a redesign in the G-EG LT rate as analyzed in this chapter. But the analysis does not provide conclusive results to support the [fixed or reservation charge] rate design concept.[11]

7. NCGC critiques that:

> PG&E's presented analysis of the historic period is replete with errors and as such it is not surprising that they found it to be inconclusive.[12]

PG&E's response: PG&E disagrees that it presented an analysis with errors.

8. NCGC next claims that the assumptions regarding Southern California Gas Company (SoCalGas) transportation rates do not change is not a "sufficient nor plausible basis upon which to make a determination as PG&E claims."[13]

PG&E's response: PG&E disagrees with NCGC's view that the assumptions on transportation rate change is not a sufficient and plausible basis to make the analysis inconclusive.

9. NCGC also claims that the assumptions regarding sunk cost recovery is not a "sufficient nor plausible basis upon which to make a determination as PG&E claims."[14]

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10 NCGC-1, p. 5, lines 4-9.

11 PG&E Errata Testimony (Aug. 18, 2022), p. 5-13, lines 13-16.

12 NCGC-1, p. 7, lines 13-14.

13 *Id.* at p. 8, lines 16-20.

14 *Ibid*.

PG&E's response: PG&E disagrees with NCGC's view that the assumptions on the inclusion of sunk cost recovery is not a sufficient and plausible basis to make the analysis inconclusive.

10. NCGC goes on to say:

> I think PG&E either incorrectly calculated the impact to G-EG BB, or mis-represented in the testimony as detailed below.[15]

PG&E's response: PG&E disagrees with NCGC saying that PG&E incorrectly calculated the impact to G-EG BB, or mis-represented in the testimony.

11. NCGC says that:

> PG&E makes the non-sequitur conclusion that the study results are inconclusive.[16]

PG&E's response: PG&E disagrees with NCGC that PG&E makes the non-sequitur[17] conclusion that the study results are inconclusive.

Q 3 Are there parties that do not dispute the analytics presented in Chapter 5?

A 3 Yes, the written prepared testimony of Calpine, Indicated Shippers, Citadel Energy Marketing LLC and Tourmaline Oil Marketing Corporation, Moss Landing, and the Small Business Utility Advocates do not dispute PG&E's Chapter 5 EG-LT Rate Design Analytics that I am sponsoring. Additionally, TURN does not dispute the use of production cost modeling, such as PLEXOS, for forecasting (and analytical) purposes.[18]

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15 *Id.* at p. 10, lines 40-42.

16 *Id.* at p. 12, lines 3-5.

17 Definition of non-sequitur:

1: An inference that does not follow from the premises.

2: A statement (such as a response) that does not follow logically from or is not clearly related to anything previously said.

https://www.merriam-webster.com/dictionary/non sequitur.

18 TURN Prepared Testimony, p. 29, line 19 to p. 30, line 1, "it is by far the most recognized and utilized method for conducting forecasting… ."

C. PG&E's Response to Parties' General Criticisms of EG-LT Rate Design Analytics

1. TURN's Criticisms of the EG-LT Rate Design Analytics Are Inaccurate and Should Be Rejected.

Q 4 What is the EG-LT Rate Design Analytics?

A 4 The G-EG LT rate design analytics is presented in PG&E's Prepared Testimony at Chapter 5, and aims to study whether a high fixed reservation charge and low volumetric rate benefits all EG customers' gas throughput on the PG&E system, comprised on EG customers taking service on LT and backbone transmission. The current G-EG LT rate design is mostly a volumetric rate. The G-EG LT rate design analytical results show conflicting indications whether a rate design high fixed reservation charge and low volumetric rate benefits all EG customers' gas throughput on the PG&E system.

Q 5 What is TURN's overall response to the analysis?

A 5 TURN seems to respond favorably overall to the analysis, calling the analysis solid,[19] then provides critiques of the analysis to discuss "finer points of disagreement."[20]

Q 6 What is TURN's first critique?

A 6 TURN's first critique is to disagree with one of the Analytics' assumptions that other gas utilities might change their own EG rate designs in response to PG&E changing its own design.[21]

Q 7 Does PG&E agree with TURN's critique? Please explain.

A 7 No, PG&E does not agree with TURN's critique that the Analytics should not take into consideration the possibility that other gas utilities might change their own EG rate designs. Other gas utilities may change its EG rate design if the utility recognizes that it is losing market share and revenue generation. From the date of service of this testimony through late in this rate case period (2026), at least a few years are available for a utility to make a change to their rate design, either in a separate rate case or by

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19 *Id.* at p. 29, line 19 to p. 30, line 3.

20 *Id.* at p .30, lines 1-3.

21 *Id.* at p. 30, lines 21-23.

negotiated rates. Moreover, if this CARD rate case changes EG-LT rate design, the economics of gas-fired EG will change. This change in the economics of generation could motivate other gas-fired electric generators in the California Independent System Operator (CAISO) marketplace to lobby for a change in other utility rate design, a point which was identified to TURN and reflected in its testimony.[22] Both the long time period from now to 2026 and the economic motivation for rate design changes, causes TURN's critique to be an irrelevant criticism that fails to put the Analytics in question.

TURN does not state that it is improper to consider another utility's potential response to a rate design change from PG&E. However, PG&E's rates offered to generators are not presented in a vaccum and may be naturally affected by other market opportunities. The generators taking gas transportation service from California gas utilities are engaged in competition in the CAISO market. Generators, if put at an economnic disadvantage, could request from its gas utility an explaoration into a possible revision to its EG transportation rate design, or a gas utility losing revenue opportunities could on its own initiative investigate revisions to its rate design. Historically, SoCalGas has had the opportunity to negotiate contract terms with its Noncore customers.[23] So, a utility responding to a revision in another utility's rates is certainly a possiblity. Instead TURN states a conclusion that utilities are too small to monitor PG&E's actions, and to conclude that a possible utility reaction to be "highly unlikely." This presumption is unsupported.

Q 8 What is TURN's second critique?

A 8 TURN disagrees with another of PG&E's Chapter 5 assumptions regarding sunk cost of the high reservation charge in the analysis. TURN claims that:

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22 *Id.* at p. 30, lines 11-20, citing to PG&E Errata Testimony (Aug. 18, 2022), p. 5-2, lines 4-13.

23 PRELIMINARY STATEMENT, Part XI, Performance Based Regulation, Sheet 16, I. 2. b. 1), <https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/4485.pdf> (as of Sept. 20, 2022).

> [H]ow those generators recover the sunk cost of the reservation charge should not be PG&E's concern… .[24]

Q 9 Does PG&E agree with TURN's critique? Please explain.

A 9 No, PG&E's analysis is concerned with generators' recovery of reservation charges. PG&E recognizes that it does not have insight on how or whether a generator can recover this sunk cost. For a generator on the PG&E system, the inability to recover this sunk cost could contribute to whether it remains viable. This would put PG&E customers at risk of undercollection of the revenue requirement during the forecast period. This is why the analysis assumed that the monthly fixed charge is a sunk cost and generators only bid their marginal cost into the market. At marginal cost recovery, it is unknown if, and if so, how, generators recover the sunk reservation cost in the wholesale marketplace.[25] However, this input is a relevant consideration to the rate design analysis. Without it, the revenue requirement could be at risk to all PG&E gas customers, who could be saddled with a higher share of revenue recovery through rates.

Q 10 Summarize TURN's third criticism with the Analytics.

A 10 TURN criticizes PG&E for wrongly concluding that the analytical evidence in support of a fixed/variable EG-LT rate design is "inconclusive."

Q 11 Does PG&E agree with TURN's criticism that the G-EG LT rate design analytical results are "inconclusive"? Please explain.

A 11 No, PG&E does not agree with TURN. PG&E's intent is to provide an unbiased presentation of the analysis, and finding inconclusive results is well supported.

As described above, the G-EG LT rate design analytics aims to show how a rate design different than current <u>benefits all EG customers' gas throughput on the PG&E system</u>. First, the PLEXOS production cost simulations clearly show that backbone connected customers do not benefit. They do not benefit because their throughput decreases. This conclusion fails to meet the primary goal of the analysis to determine whether *all*

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24 TURN Prepared Testimony, p. 32, lines 9-12.

25 PG&E Errata Testimony (Aug. 18, 2022), p. 5-10, lines 23-26.

customers benefit from the rate design. As presented in its Prepared Testimony, backbone connected EG plants lose market share, because:

> [T]he increase in LT throughput is offset by approximately 30 percent to 40 percent decline in BB [backbone] throughput.[26]

Second, the historical analysis clearly illustrates that EG gas throughput is correlated with other conditions. PG&E's analysis shows that electric load and hydroelectric conditions are relevant.[27] Moreover, the historical analysis shows that generators on the renegotiated rate throughput increased 8 percent and backbone generators increased even more at 22 percent.[28] The historical and simulation analytics clearly show inconclusive results.

Q 12 Summarize TURN's fourth criticism with the G-EG LT rate design analytics.

A 12 PG&E testified that "[c]onflicting results consist of a decline in EG BB customers throughput while EG LT customers throughput increases."[29] TURN criticizes this conclusion by stating that "results are not really conflicting at all, as the increased generation by EG-LT customers has to be matched by reduced generation from somewhere else."[30]

Q 13 Does PG&E agree with TURN's criticism that the results are "not really conflicting"? Please explain.

A 13 No, PG&E does not agree with TURN that the G-EG LT rate design analytical results are "not really conflicting."

The PLEXOS production cost modeling, that TURN purposefully relies on for its testimony, does show conflicting results. PG&E's analytics aimed to show how a different than current rate design benefits all EG customers' gas throughput on the PG&E system. The results show an increase in EG-LT customer throughput and a decrease in EG-BB customer throughput. This goes against PG&E's study objective to determine whether all EG

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26 *Id.* at p. 5-12, lines 11-12.

27 *Id.* at p. 5-9, Table 5-4.

28 *Id.* at p. 5-8, Table 5-3.

29 *Id.* at p. 5-2, line 28 to p. 5-3, line 1.

30 TURN Prepared Testimony, p. 32, lines 14-16.

customers' gas throughput increase, since the EG-BB customer throughput decreases.

Q 14 Summarize TURN's fifth criticism with the G-EG LT rate design analytics.

A 14 TURN criticizes the historical analysis in Chapter 5 with its statement that:

> [I]n contrast, PG&E's 'historical analysis' is simply not a reliable approach to evaluating the impact of the change in EG-LT rate design.[31]

Q 15 Does PG&E agree with TURN's criticism that PG&E's historical analysis is not a reliable approach to evaluating the impact of the change in EG-LT rate design? Please explain.

A 15 No, PG&E does not agree with TURN. The historical analysis shows whether EG throughput increases or stabilizes. This historical analysis did show that on average EG-LT throughput on the renegotiated rate did increase by 8 percent. However, at the same time EG-BB throughput increased more, by 22 percent.[32] This clearly shows that something else, <u>i.e., factors other than the negotiated fixed charge rate design,</u> impact EG throughput on PG&E's system. Also, EG throughput shows correlation to other electric market conditions, both changes in electric load and hydroelectric generation.[33] The correlation of these two factors shows that something else impact EG throughput.

TURN does not provide sufficient reason to conclude that the historical analysis of the renegotiated rate for some EG-LT customers is unreliable. TURN cites to the conclusion that there could be a "myriad of factors that could influence EG gas demand."[34] While several factors may be present in the analysis of gas demand, it is not a reason to eschew this historical analysis as an unreliable input for consideration.

Since the historical data analysis was inconclusive to make a decision regarding the rate design concept, PG&E used production cost modeling to isolate EG gas throughput and the G-EG LT rate design concept. This helps

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31 *Id.* at p. 33, lines 1-2.

32 PG&E Errata Testimony (Aug. 18, 2022), p. 5-8, Table 5-3.

33 *Id.* at p. 5-9, Table 5-4.

34 TURN Prepared Testimony, p. 33, lines 2-3.

to examine a single change to understand if the rate design concept impacts gas throughput.[35]

2. NCGC'S Criticisms of the EG-LT Rate Design Analytics are Inaccurate and Should be Rejected.

Q 16 Summarize NCGC's first criticism with the G-EG LT rate design analytics.

A 16 NCGC criticizes the Chapter 5 analytical results, saying that PG&E's analysis "fails to accurately reflect the situation" and "does not show that maintaining the *status quo* is better than the change requested by customers."[36]

Q 17 Does PG&E agree with NCGC's criticism saying that PG&E's analysis fails to accurately reflect the situation? Please explain.

A 17 No, PG&E disagrees with NCGC's criticism. As an initial matter, PG&E cannot fully respond because it is not clear what NCGC refers to by the word "situation."

PG&E's analytics examined a different rate design for EG-LT connected customers. What the analysis did was to compare the EG throughput impacts of a high reservation rate and low volumetric rate against the current all volumetric rate design. This analysis does not compare the existing EG-LT rate design against some other rate design.

Q 18 Summarize NCGC's second criticism with the G-EG LT rate design analytics.

A 18 NCGC criticizes the historical Chapter 5 analytical results claiming that PG&E's analysis is replete with errors.

Q 19 What is PG&E's response?

A 19 PG&E disagrees with NCGC's criticism that PG&E's analysis is replete with errors. NCGC does not explicitly list the errors it claims the analysis contains. NCGC does say that there "were a number of factors that varied"[37] during the historical data analyzed. It listed temperature and precipitation as a couple of examples. PG&E's correlation analysis

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35 PG&E Errata Testimony (Aug. 18, 2022), p. 5-9, lines 1-5.

36 NCGC-1, p. 5, lines 3-9.

37 *Id.* at p. 6, lines 25-27.

addresses these factors.[38] Temperature drives electric load, particularly in the summer. PG&E's analysis in Table 5-4 correlated the CAISO electric load and G-EG throughput. This Table also shows the correlation of CAISO hydroelectric generation and E-EG throughput. The hydroelectric generation is a similar driver to precipitation. The use of these two factors diminishes NCGC's critique.

NCGC states that the historical data clearly showed significant higher usage by the market-responsive generation on the G-EG LT with a negotiated fixed/variable rate structure. NCGC is referring to Table 5-3 in the Analytics.[39] One, if NCGC believes that PG&E's analysis is replete with errors, then NCGC's reliance on Table 5-3 to support it claim that G-EG LT showed significant higher usage is suspect. NCGC appears to criticize the analysis, then relies on the same analysis to support its position.

On the other hand, PG&E's testimony provides two simple analyses of historical gas throughput. The first analysis examines the before and after throughput impact from the implementation of the renegotiated fixed rate contract. The analysis looked at both the EG-LT and EG-BB classes. This examination also splits the EG-LT throughput for those customers that took the renegotiated rate and those who did not. The analysis calculated the average throughput for each sub-section of EG customer types. The table below recreates Table 5-3 from PG&E's Chapter 5 testimony,[40] summarizing the analysis.

38 PG&E Errata Testimony (Aug. 18, 2022), p. 5-9, Table 5-4.

39 *Id.* at p. 5-7, Table 5-3.

40 *Id.* at p. 5-8, Table 5-3.

TABLE 5-1
HISTORICAL ANALYSIS GAS THROUGHPUT SUMMARY STATISTICS

Line No.	Throughput Groups	Before Renegotiated Rate Throughput thousand dekatherms per day (MDth/d) Jan-2018 through Sep-2019	After Renegotiated Rate Throughput (MDth/d) Oct-2019 through Jun-2021	Percent Change
1	G-EG LT on the renegotiated rate	190	205	8%
2	G-EG LT on the current rate	79	80	1%
3	G-EG LT Total	270	285	6%
4	G-EG BB Total	305	371	22%

Note: Recreated from PG&E's Prepared Testimony, p. 5-8, Table 5-1.

The results show that the EG-LT customers on the renegotiated rate, although increased 8 percent, did not increase as much as EG-BB customers at 22 percent.

Second, the historical analysis looks at the correlation of EG throughput by the sub-section of EG customer types with other factors in the CAISO electric market. The two factors are electric load and hydroelectric generation. The analysis shows that for a change in electric load, EG throughput changes. Here, for example, an increase in electric load shows a likewise increase in EG throughput. For hydroelectric generation, the correlation takes an opposite direction. When hydroelectric generation decreases, EG throughput increases. Table 5-4 in PG&E's Chapter 5 testimony finds that this is correct. As electric load increases, the correlation analysis shows an increase in EG throughput. For hydroelectric generation, the negative sign in Table 5-4 shows that as hydroelectric generation decreases, EG throughput increases and vice versa. The logic and numerical results of these two simple analyses have no errors.

Q 20 Summarize NCGC's third criticism with the G-EG LT rate design analytics.

A 20 NCGC claims that the assumptions regarding SoCalGas transportation rates not changing is not a "sufficient nor plausible basis upon which to make a determination as PG&E claims."[41]

Q 21 Does PG&E agree? Please explain.

A 21 No, PG&E disagrees with NCGC's claim that no change in SoCalGas transportation rates is not a "sufficient nor plausible basis upon which to make a determination as PG&E claims." Just as NCGC testifies, the "marginal clearing price of the CAISO market when gas-fired generation is the marginal resource."[42] So, if a utility like SoCalGas makes a change to its transportation rates and changes the marginal cost of the marginal resource, this should impact EG throughput on the PG&E system. The logic above demonstrates why PG&E is concerned with this assumption about other gas transportation rates and is a sufficient basis to show that the analysis is inconclusive.

Q 22 Summarize NCGC's fourth criticism with the G-EG LT rate design analytics.

A 22 NCGC claims that the assumptions regarding sunk cost recovery is not a "sufficient nor plausible basis upon which to make a determination as PG&E claims."

Q 23 Does PG&E agree? Please explain.

A 23 No, PG&E disagrees with NCGC's claim regarding sunk cost recovery. PG&E recognizes that it does not have insight on how or whether a generator can recover this sunk cost. For a generator on the PG&E system, the inability to recover this sunk cost could contribute to whether it remains viable. This would put PG&E customers at risk of undercollection of the revenue requirement. PG&E also provided this information in response to a similar criticism from TURN, in Question and Answer eight and nine, above.

Q 24 Summarize NCGC's fifth criticism with the G-EG LT rate design analytics.

A 24 NCGC says that:

> I think PG&E either incorrectly calculated the impact to G-EG BB, or mis-presented in the testimony as detailed below.[43]

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41 NCGC-1, p. 8, lines 16-20.

42 *Id.* at p. 3, lines 2-3.

43 *Id.* at p. 10, lines 40-42.

Q 25 Does PG&E agree with NCGC's criticism saying that PG&E incorrectly calculated the impact to G-EG BB, or mis-presented in the testimony as detailed below? Please explain.

A 25 No, PG&E disagrees with NCGC's saying that PG&E incorrectly calculated the impact to G-EG BB or mis-presented the impact in PG&E's testimony. PG&E did not miscalculate the impact of backbone throughput or misrepresent the impact of backbone throughput.

NCGC misconstrues the PG&E numbers. The PG&E numbers represent the amount of EG BB throughput change for the change in EG LT throughput. These are the quantity of decline.[44] Figure 5-1 recreates Figure 5-2 from PG&E's Chapter 5 testimony.[45] This figure summarizes the analytical results with EG BB throughput declining between 30 percent – 40 percent. This calculation takes the EG BB throughput decrease divided by the EG LT throughput increase. These calculations are shown below:

a. 2023: **-**18 MDth/d ÷ 49 MDth/d = **-**37%

b. 2024: **-**17 MDth/d ÷ 46 MDth/d = **-**37%

c. 2025: **-**15 MDth/d ÷ 47 MDth/d = **-**32%

d. 2026: **-**18 MDth/d ÷ 50 MDth/d = **-**36%

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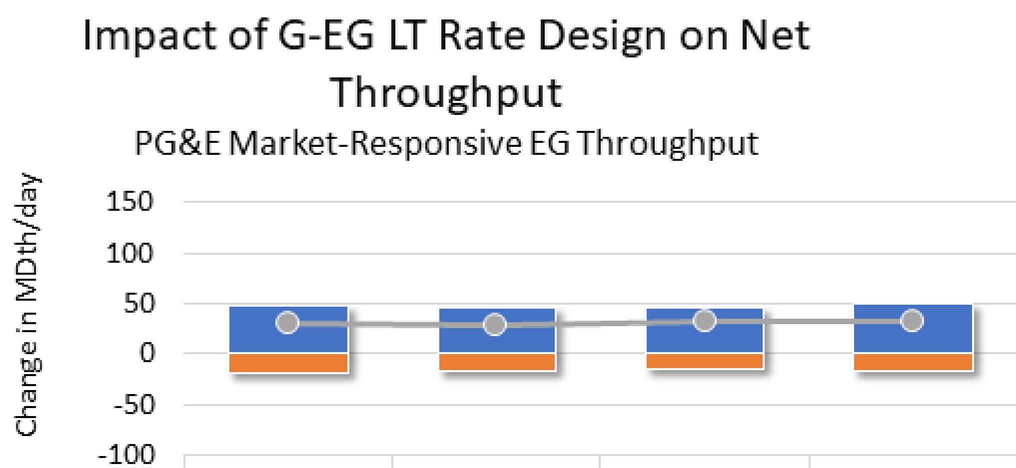
44 *Id.* at p. 11, lines 4-6.

45 PG&E Errata Testimony (Aug. 18, 2022), p. 5-13, Figure 5-2.

FIGURE 5-1
EG NET GAS THROUGHPUT
BASE CASE AND G EG LT RATE DESIGN CONCEPT



	2023	2024	2025	2026
Mkt. Resp., LT	49	46	47	50
Mkt. Resp., BB	-18	-17	-15	-18
Mkt. Resp., Total	31	29	32	33

Second, NCGC confuses the use of backbone throughput with throughput for the EG-LT customers. The backbone throughput NCGC refers to is the portion of the PG&E gas system that transport gas from the California borders on the Redwood and Baja paths.[46] This is different than the EG class connected to the backbone system. This latter refers to throughput based on the gas schedule G-EG.[47] Additionally, NCGC attempts to expand the scope of the Chapter 5 analysis by introducing throughput on the backbone system. NCGC writes "that BB throughput has declined when in fact total BB throughput has increased."[48] However, the analysis PG&E performed looked at throughput for EG customers under the G-EG tariff[49] – both EG-BB and EG-LT (aka EG – All Other Customers).

[46] For example, PG&E's California Gas Transmission transportation under schedules G-AFT and G-SFT.

[47] Gas Transportation Service to Electric Generation, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHEDS_G-EG.pdf.

[48] NCGC-1, p. 11, lines 10-14

[49] Gas Schedule G-EG, <https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHEDS_G-EG.pdf> (as of Sept. 20, 2022).

NCGC's criticism is irrelevant when looking at rate design impacts to the backbone throughput.

Third, NCGC states that:

> PG&E makes the following statement 'Yet, less efficient and/or higher operational cost BB connected EG plants lose market share.' It is unclear why PG&E chose to include this statement in its testimony… .[50]

To clarify, PG&E's statement explains the results of the PLEXOS production cost simulation analysis.

Q 26 Summarize NCGC's sixth criticism with the G-EG LT rate design analytics.

A 26 NCGC says that "PG&E makes the non-sequitur conclusion that the study results are inconclusive."

Q 27 Does PG&E agree with NCGC's criticism that "PG&E makes the non-sequitur conclusion that the study results are inconclusive."? Please explain.

A 27 No, PG&E disagrees with NCGC's criticism that PG&E's analysis is non-sequitur conclusions. As explained in more detail above, PG&E provides two types of analyses: historical and production cost simulations.

The historical analyses provide two views. The first is the average throughput for all EG classes before and after the 2019 renegotiated EG-LT rates. The second used correlation analysis to examine how EG gas throughput correlates to other market conditions. These are electric load and hydroelectric generation. These two historical data analyses are logically based and use simple methods to conclude that the study results are inconclusive.

The second analysis uses production cost simulation. PG&E uses the PLEXOS software production cost model for forecasting and analysis. PLEXOS is a sound industry-endorsed PLEXOS production cost model. As described in PG&E's Workpapers,[51] PLEXOS is an industry recognized

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50 NCGC-1, p. 11, lines 19-22.

51 PG&E Workpapers Supporting Chapter 2A, Confidential, p. 1.

production cost model as used by the CEC.[52] It is also used by others in the industry, such as CAISO, and globally.[53] TURN states that:

> PG&E's production cost modeling…is by far the most recognized and utilized method for conducting forecasting of this nature, because it takes into account the impacts of a wide variety of variables on EG gas demand…[54]

This modeling and analysis approach, endorsed by industry and recognized by TURN in its testimony supports that the Chapter 5 analysis is thorough and logical.

D. Conclusion

Q 28 What is PG&E's recommendation for Chapter 5 EG-LT Rate Design Analtyics?

A 28 PG&E recommends the Commission accepts the validity of the analytics as presented in Chapter 5, for purposes of deciding rate design issues contained in Chapter 6.

Q 29 Does this conclude your rebuttal testimony?

A 29 Yes it does.

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52 California Energy Commission, Final 2021 Integrated Energy Policy Report Volume III Decarbonizing the State's Gas System (Mar. 2022), <https://efiling.energy.ca.gov/GetDocument.aspx?tn=242233> (as of Sept. 20, 2022).

53 Energy Exemplar, PLEXOS, The Unified Energy Market Simulation Platform, <https://www.energyexemplar.com/plexos> (as of Sept. 20, 2022).

54 TURN Prepared Testimony, p. 29, line 19 to p. 30, line 1.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

REBUTTAL TESTIMONY OF

PATRICIA C. GIDEON AND JAMES CHEN ON

COST ALLOCATION AND RATE DESIGN

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
REBUTTAL TESTIMONY OF
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
REBUTTAL TESTIMONY OF
PATRICIA C. GIDEON AND JAMES CHEN ON
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
REBUTTAL TESTIMONY OF
PATRICIA C. GIDEON AND JAMES CHEN ON
COST ALLOCATION AND RATE DESIGN

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Patricia C. Gideon, and I am a Principal Gas Rate Analyst. This testimony responds to the direct testimony of Small Business Utility Advocates (SBUA),[1] The Utility Reform Network (TURN),[2] Calpine Corporation (Calpine),[3] Moss Landing Power Plant Company LLC (Moss Landing),[4] and Northern California Generation Coalition (NCGC).[5] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below. PG&E first identifies PG&E's proposals that remain undisputed, then discusses parties' recommendations with which PG&E agrees in full or in part, and lastly PG&E discusses issues in dispute.

Q 2 Please state your name and the purpose of your rebuttal testimony.

A 2 My name is James Chen, Expert Gas Transmission Product Manager. My testimony responds to the direct testimony of TURN on the issue of the allocation of storage costs to Core Gas Supply (CGS) on pages 6-29 through 6-30, Q&A 71 and 72.

Q 3 Does PG&E have any changes or clarifications to its Chapter 6 proposals?

A 3 Yes. On page 6-15 of PG&E's Errata Testimony filed August 18, 2022, on lines 11 through 17, the discussion was intended to refer to the balancing account true-up of actual versus adopted revenue requirements, not the implemented rate recovery, which will be differentiated by end-use customer

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1 SBUA Direct Testimony, pp. 13-20.

2 TURN Prepared Testimony, Ch. 6.

3 Calpine Prepared Testimony, Sections IV and V.

4 MLPC-01, p. 3, line 9 to p. 9, line 7.

5 NCGC-1.

class. Please refer to Attachment A at the end of this chapter for the corrected testimony.

B. Summary of Parties Positions and PG&E's Responses

1. Undisputed Issues

Q 4 Are there proposals that parties do not dispute?

A 4 Yes. No party submitted written testimony that disputes PG&E's proposals for the following issues that I am sponsoring:

Backbone Transmission

- The treatment of Core Vintage Redwood costs;[6]
- The allocation of common backbone costs, including Reserve Capacity, to each backbone path based on a pro rata share of the firm design capacities of each path;[7]
- The calculation of backbone revenue requirements, segmented between core and noncore, by path, based on firm design capacities;[8]
- Basing the G-XF revenue requirement on G-XF customers' firm contract quantities (85.8 thousand dekatherms);[9] and
- Basing the seasonal two-part Modified Fixed-Variable and Straight Fixed-Variable rate options and volumetric as-available rates on 120 percent of the corresponding annual firm rate.[10]

Local Transmission (LT) End-Use Service

- Adjusting the LT Cost Allocation and Rate Design (CARD) to account for forecast LT rate discounts;[11]
- A single average LT rate for all core classes and a single average LT rate for all noncore (with the exception of Electric Generation Local Transmission (EG-LT)) and wholesale customer classes;[12] and

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6 PG&E Errata Testimony (Aug. 18, 2022), p. 6-10, lines 5-25.

7 *Id.* at p. 6-8, lines 8-11.

8 *Id.* at p. 6-8, lines 11-13.

9 *Id.* at p. 6-8, lines 18-19.

10 *Id.* at p. 6-11, lines 2-5.

11 *Id.* at p. 6-12, lines 4-5.

12 *Id.* at p. 6-12, lines 4-7.

- LT rates continue to be non-bypassable for all customers not qualifying for backbone-level end-user service.[13]

Storage Cost Allocation and Rate Design

- The allocation of storage cost of service, including PG&E's share of Gill Ranch, to the storage services (core firm, inventory management and reserve capacity) based on the pro rata share of current annual injection, inventory and withdrawal cycling capacity assigned to each service for the 2023-2026 rate case period;[14]
- The recovery of Reserve Capacity costs in backbone rates;[15]
- To continue the existing tariffed maximum charge for G-PARK and G-LEND services at the rates adopted for 2022 in the 2019 Gas Transmission and Storage (GT&S) Rate Case;[16]
- The allocation of G-PARK and G-LEND revenues between core and noncore customers based on their proportional share of the total storage revenue requirements;[17]
- The return of G-PARK and G-LEND revenues allocated to core customers through the Core Cost Subaccount of the Core Fixed Cost Account and the return of G-PARK and G-LEND revenues allocated to noncore customers through the Noncore Subaccount of the Noncore Customer Class Charge Account (NCA);[18]
- Calculating the Self-Balancing Credit by first separating the costs associated with monthly balancing from the costs associated with intra-day balancing using historic monthly balancing storage units and then applying a factor of 80 percent of the total storage balancing assets;[19]

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13 *Id.* at p. 6-12, lines 13-14.

14 *Id.* at p. 6-13, lines 10-15.

15 *Id.* at p. 6-15, lines 2-4. TURN notes that in General Rate Case (GRC) 1, there is an active proposal to eliminate the Reserve Capacity service altogether (TURN Prepared Testimony, p. 38, lines 16-19).

16 *Id.* at p. 6-14, lines 13-15.

17 *Id.* at p. 6-14, lines 16-20.

18 *Id.* at p. 6-14, lines 20-25.

19 *Id.* at p. 6-23, lines 10-18.

- Returning in 2023 the depreciation and decommissioning revenues previously collected in end-use rates for the Los Medanos storage field using the currently adopted allocation methodology;[20]
- Collecting in 2023 the Pleasant Creek Storage Fields depreciation costs in end-use rates using the currently adopted allocation methodology;[21]
- Collecting in 2023-2026 the Pleasant Creek Storage Fields decommissioning costs in end-use rates using the currently adopted allocation methodology;[22] and
- Continuing to blend the storage revenue requirements in backbone transmission and bundled core end-user rates to create annual average backbone transmission and bundled core end-user rates for as long as necessary.[23]

Timing of Decision and Implementation

- To work with the Energy Division to develop a mutually acceptable implementation plan for the 2023 CARD should a decision not be issued within the Rate Case Plan timeframe for PG&E's 2023 GRC I.[24]

2. Issues With Which PG&E Agrees in Full or in Part

Q 5 Does PG&E agree with any of parties' recommendations?

A 5 Yes, PG&E agrees with TURN's recommendations regarding the allocation of storage costs between injection and withdrawal functions.

Q 6 Does PG&E agree in part with any of parties' recommendations?

A 6 Yes. PG&E agrees in part with

- TURN's proposal to weight Inter- and Intra-Day imbalances on a 50/50 basis rather than PG&E's proposed 37/63 weighting for purposes of allocating inventory management costs for the 2023-2026 period,

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[20] *Id.* at p. 6-24, line 13 to p. 6-25, line 3. Note that this proposal is dependent on approval of the proposal to retain the Los Medanos storage field in PG&E's GRC 1, A.21-06-021.

[21] *Id.* at p. 6-25, lines 4-6.

[22] *Id.* at p. 6-25, lines 6-9.

[23] *Id.* at p. 6-25, line 14 to p. 6-26, line 2.

[24] *Id.* at p. 6-33, lines 17-22.

- TURN’s proposal to refrain from using variance as a proxy of volatility for the 2023-2026 period in order to further subdivide the allocation of inventory management costs into specific customer classes, and,
- Calpine’s proposal to weight historic usage by class to scale to forecast usage by class.

3. Disputed Issues

Q 7 Do parties criticize PG&E’s showing regarding the cost allocation and/or rate designs proposed in PG&E’s 2023 CARD application?

A 7 Yes, parties criticize certain PG&E proposals regarding the allocation and recovery of storage costs, the design of EG-LT rates, the allocation of storage costs to CGS, and the residential and small commercial Customer Access Charges (CAC).

Q 8 Does PG&E disagree with any of parties’ recommendations?

A 8 Yes, PG&E disagrees with recommendations made by parties regarding the following proposals:

<u>Issue 1</u>

- Certain aspects of parties’ proposals regarding the recovery of Inventory Management costs in end-user rates, specifically, SBUA’s proposal to retain the status quo recovery of Inventory Management costs bundled in backbone rates,

<u>PG&E Response (Section C.1.a.)</u>

- Relative to the status quo methodology, PG&E’s proposal to recover Inventory Management costs in end-user transportation rates where it can be differentiated among customer classes more fairly allocates the cost of this service based on the class usage of the service.

<u>Issue 2</u>

- Calpine’s proposal to maintain the status quo with respect to collecting inter-day balancing costs bundled in backbone rates and to only collect intra-day balancing costs in end-user transportation rates.

<u>PG&E Response (Section C.1.b.3)</u>

- Recovering intra-day balancing, but not inter-day balancing in end-use transportation rates would result in an incomplete price signal of the inventory management service based on cost causation.

<u>Issue 3</u>

- The fixed component rate design of Market Responsive EG-LT rates.

<u>PG&E Response (Section C.2)</u>

- PG&E recommends rejection of proposals for any fixed component rate design of Market Responsive EG-LT rates. The results of the study conducted by PG&E and described in Chapter 5 of PG&E's Errata Testimony dated August 18, 2022, did not provide a clear basis to propose an EG-LT rate design that diverges from the status quo by incorporating a fixed charge component.

<u>Issue 4</u>

- TURN's proposal to limit the cost of storage assigned to CGS Firm Storage to what CGS would pay if it purchased storage in the market from Independent Storage Providers (ISP).

<u>PG&E Response (Section C.4)</u>

- There should be no change to the allocation of storage costs to CGS because TURN's recommendation is based on an incorrect assumption that CGS is being "assigned" excess capacity.

<u>Issue 5</u>

- The CAC for residential and small commercial classes of customers.

<u>PG&E Response (Section C.5)</u>

- This issue is out of scope for the CARD proceeding because the CARD sets only transmission level CACs. The Gas Cost Allocation Proceeding (GCAP) is the appropriate proceeding to address distribution level CACs, aka customer charges.

C. Discussion of Parties Criticisms to PG&E's Proposals

1. PG&E's Response to Parties' General Criticisms Regarding Recovery of Inventory Management Costs in End-User Rates

Q 9 What is PG&E's proposal regarding recovery of Inventory Management costs? Please describe.

A 9 Inventory Management service, first established as part of PG&E's Natural Gas Storage Strategy (NGSS) adopted in PG&E's 2019 GT&S case, uses a portion of PG&E's storage service to maintain safe and reliable pressure and gas service on an hourly and daily basis.[25] Currently, Inventory

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[25] *Id.* at p. 6-15, lines 19-23.

Management is treated as a common cost that is recovered on an effective equal cents per therm basis across customers using PG&E's backbone transmission system.[26]

In this CARD, PG&E proposes to recover Inventory Management costs in end-user transportation rates with differentiation among classes based on a two-part analysis. As more fully detailed in PG&E's Prepared Testimony,[27] PG&E proposes to treat Inventory Management costs as follows:

> PG&E proposes to move the recovery of Inventory Management from its unbundled backbone transmission rates to its end-use transportation rates where it can differentiate cost recovery by customer class in a manner reflective of cost causation and utilization of the service. ~~Costs~~ [Over- or undercollections] associated with Inventory Management and allocated to Core customers will be recovered, on an equal cents per therm basis through the Core Cost Subaccount of the Core Fixed Cost Account (CFCA). Costs associated with Inventory Management and allocated to Noncore customers will be recovered, on an equal cents per therm basis, through the Noncore Subaccount of the Noncore Customer Class Charge Account (NCA).[28]

Q 10 Which parties commented on the proposed recovery of Inventory Management costs in end-user rates?

A 10 SBUA, TURN and Calpine address this proposal.

a. SBUA's Recommendation to Continue the Recovery of Inventory Management Costs Should Be Rejected Because PG&E's Proposal More Fairly Allocates the Cost of This Service Based on the Class Usage of the Service

Q 11 SBUA is the only party to completely reject PG&E's proposal to move recovery of Inventory Management costs from backbone transmission rates to end-user transportation rates. Please explain SBUA's reasoning for rejecting the proposal to recover Inventory Management costs in end-user transportation rates.[29]

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26 *Id.* at p. 6-15, line 30 to p. 6-16, line 3.

27 *Id.* at Section F 2.

28 *Id.* at p. 6-15, lines 7-17, as clarified in Q&A 3 on p. 6-1, and Attachment A at the end of this chapter.

29 SBUA Direct Testimony, pp 16-17.

A 11 SBUA argues that PG&E's proposal forces "small commercial and residential customers to subsidize storage" and should not be adopted "absent a narrowly defined benefit for doing so."[30]

Q 12 What is the rationale behind SBUA's claim?

A 12 SBUA claims that because:

> [E]lectric generators generally require large amounts of natural gas storage during the summer months [and] demand for residential and small commercial customers is generally higher during the winter months…[f]rom an aggregate perspective, [there should be] some degree of a cancelling effect.[31]

Q 13 Do you agree with SBUA's criticism?

A 13 No, PG&E disagrees and believes the criticism is irrelevant to the proposal for Inventory Management. Whether or not some subset of end-use customers with volatile load profiles on an hourly and/or daily basis have generally seasonally complimentary demands for a service is not relevant to this proposal. SBUA's argument ignores other major customer classes, however, a cost allocation must consider all customer classes and cost causation. Further, PG&E's analysis concludes that the *current* recovery of Inventory Management on an equal cents per therm basis in unbundled backbone transmission rates results in a subsidization of residential and small commercial customers, as well as electric generation and wholesale customers by large commercial, noncore Natural Gas Vehicle (NGV) and industrial customers.[32]

Q 14 What customer classes does SBUA disregard?

A 14 SBUA disregards the Large Commercial, Core NGV, Industrial Distribution, Industrial Transmission, and Industrial Backbone end-use customer classes. These classes have a lower cost of service for Inventory Management service than residential and small commercial customer classes. By not discussing all classes in its testimony or presenting an argument or analysis as to why residential or small commercial customers classes are not indeed

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30 *Id.* at p. 17.

31 *Ibid*.

32 PG&E Errata Testimony (Aug. 18, 2022), Section F.2.e, p. 6-17, line 12 to p. 6-23, Table 6-12.

lower cost of service, SBUA's analysis is incomplete and fails to account for classes that contribute to costs for the Inventory Management service. PG&E's proposal and analysis considers the costs of the Inventory Management Service to all customer classes.[33]

Q 15 What does PG&E's analysis indicate about the customer classes that are disregarded by SBUA?

A 15 PG&E's analysis of inventory management cost causation and service utilization[34] indicates that these large commercial/industrial customer classes have a far lower cost of service causation for the Inventory Management service than the residential, electric generation, and wholesale customer classes. The large commercial and industrial customer classes demands are only modestly impacted by the volatility of temperatures, compared to the substantial demand impacts of temperature on an hourly and daily basis on classes such as residential/small commercial and electric generation[35]

Q 16 What is PG&E's conclusion regarding SBUA's request that PG&E's Inventory Management proposal be denied?

A 16 SBUA's recommendation should be denied in favor of a cost recovery proposal that equitably accounts for the cost causation differentials among various end-user customer classes to provide Inventory Management. Cost would be allocated for recovery according to the cost to serve (i.e., cost causation by, each class, and benefit derived by each class). Under the analysis performed by PG&E, this new allocation would result in a larger allocation to residential/small commercial, electric generation, and wholesale customer classes than they are currently paying and a reduced allocation to large commercial, core NGV, and the industrial customer classes, as summarized in PG&E's prepared testimony

Q 17 Does SBUA provide any additional rationale for its position for rejection of PG&E's Inventory Management cost recovery proposal?

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33 *Ibid.*

34 *Ibid.*

35 This relationship can be seen by comparing, across months, the cold temperature throughput forecast to the average temperature forecast for the various customer classes as proposed in PG&E Errata Testimony (Aug. 18, 2022), Chapters 2A and 2B.

A 17 Yes. SBUA claims that natural gas storage is cheaper in the winter months and provides the following analogy:

> [F]rom an electric generator's standpoint, if the underground natural gas storage facilities are a balloon, then the balloon would be filled in the winter and expelled during the summer. The opposite would be true for small commercial and residential customers, so the two *should* compliment each other.[36]

Q 18 Does PG&E agree with SBUA's conclusion?

A 18 No. SBUA has provided no information to support its claim that natural gas storage is cheaper in the winter months and, in response to PG&E's request to provide supporting documentation for its claim, acknowledged that "it is possible that this statement may not be true."[37]

Q 19 What is SBUA's recommendation?

A 19 SBUA recommends that the Commission not adopt PG&E's proposal.[38]

Q 20 Do you agree with SBUA's recommendation?

A 20 No. Even at the level of the three broad customer segments (Core, Electric Generation and Industrial), PG&E's analysis shows very different levels of hourly and daily imbalances.[39] As these imbalances drive utilization of the inventory management service, then from a cost causation perspective, it would not be equitable to charge all customers the same rate for the service as is the case currently.[40] PG&E's proposal recognizes the differences in the utilization of inventory management services and more fairly, relative to status quo methodology, allocates the costs in accordance with each customer class's usage of the service. As PG&E noted in its opening testimony, given the relative increase in the cost of storage services, it is

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36 SBUA Direct Testimony, p. 17.

37 SBUA Response to PG&E Data Requests, Set One, Question 6, dated 9/14/2022, in Attachment B at the end of this chapter. (In response to a question, "SBUA testifies, 'Furthermore, natural gas storage is cheaper in the winter month,' SBUA responded, "Expert Brown acknowledges that it is possible that this statement may not be true.")

38 SBUA Direct Testimony, p. 16.

39 PG&E Errata Testimony (Aug. 18, 2022), p. 6-18, Table 6-4.

40 Inventory Management costs are currently recovered backbone transmission rates where all customers effectively pay the same rate for the service.

appropriate to differentiate cost recovery of this service by end-user customer class.[41]

b. TURN and Calpine Have Limited Criticisms, but Do Not Completely Reject PG&E's Proposal for Recovery of Inventory Management Costs

Q 21 Do any other parties have criticisms about various aspects of PG&E's proposal for recovery of Inventory Management costs in end-user transporation rates while not completely rejecting it? Please describe.

A 21 Yes, two other parties have limited criticisms about PG&E's proposal for recovery of Inventory Management costs in end-user rates, while not completely rejecting the concept:

- TURN states that the proposed weighting between Inter- and Intra-Day imbalances (37 percent and 63 percent, respectively), based on volumes alone, cannot be determined to be accurate or sensible, absent a more detailed assessment of the relative impacts on Inter- and Intra-Day imbalances on system operations.
- TURN states that the subdivision of the three broad customer segments (Core, Electric Generation and Industrial)—analyzed into specific customer classes—is premature, given the scope of the information available at this time.
- Calpine recommends that all shippers should continue to pay for the inter-day portion of Inventory Management balancing services as part of backbone rates, and on the status quo equal cents-per-therm basis.
- Calpine recommends that the allocation calculations of intra-day Inventory Management costs should reflect the throughput forecast for this CARD case.

1) TURN's Criticism of PG&E's Proposal to Use a 50/50 Weighting of Inter- and Intra-Day Imbalances in the Initial Step of Allocating Inventory Management Costs in This Proceeding Is Reasonable

Q 22 What is TURN's criticism of PG&E's proposal to recover Inventory Management costs in end-user rates? Please describe.

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41 PG&E Errata Testimony (Aug. 18, 2022), p. 6-15, lines 6-11.

A 22 TURN states that the proposed weighting between Inter- and Intra-Day imbalances (37 percent and 63 percent, respectively), based on volumes alone, cannot be determined to be accurate or sensible absent a more detailed assessment of the relative impacts on Inter- and Intra-Day imbalances on system operations. Given that this is the first time this type of analysis has been presented to the Commission, TURN recommends that PG&E use a 50/50 weighting between Inter- and Intra-day imbalances.[42]

Q 23 Do you agree with TURN's recommendation?

A 23 Subject to the qualification in this response, yes, PG&E agrees to modify its proposal in the 2023 GT&S CARD to use the 50/50 weighting method as a reasonable approach for this CARD cycle only. PG&E notes that it prepared an analysis of a 50/50 weighting method in Table 6-4 of its prepared testimony.[43] PG&E agrees to the 50/50 method, with the reservation that further analysis may lead for further consideration of new recommendations for a differentiated weighting between Inter-and Intra-Day services after additional analysis. These analyses and recommendations could be presented in a future CARD or appropriate proceeding.

2) PG&E's Revised Inventory Management Proposal Should Be Adopted, In Order to Address TURN's Concern Regarding the Use of Data to Subdivide the Three Customer Segments

Q 24 What is the second criticism of PG&E's proposal to recover Inventory Management costs in end-user rates? Please describe.

A 24 TURN states that the subdivision by PG&E of the three broad customer segments—Core, Electric Generation, and Industrial—(referred to herein as the "Big 3") analyzed into specific customer[44] classes "is premature given the scope of the information available at this time."[45]

Q 25 Do you agree with TURN's criticism?

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42 TURN Prepared Testimony, p. 46, lines 1-4.

43 PG&E Errata Testimony (Aug. 18, 2022), p. 6-18, Table 6-4.

44 PG&E's segmentation proposal used Variance analysis by customer class as discussed in PG&E Errata Testimony (Aug. 18, 2022), p. 6-19, lines 3-17.

45 TURN Prepared Testimony, p. 45, lines 18-22.

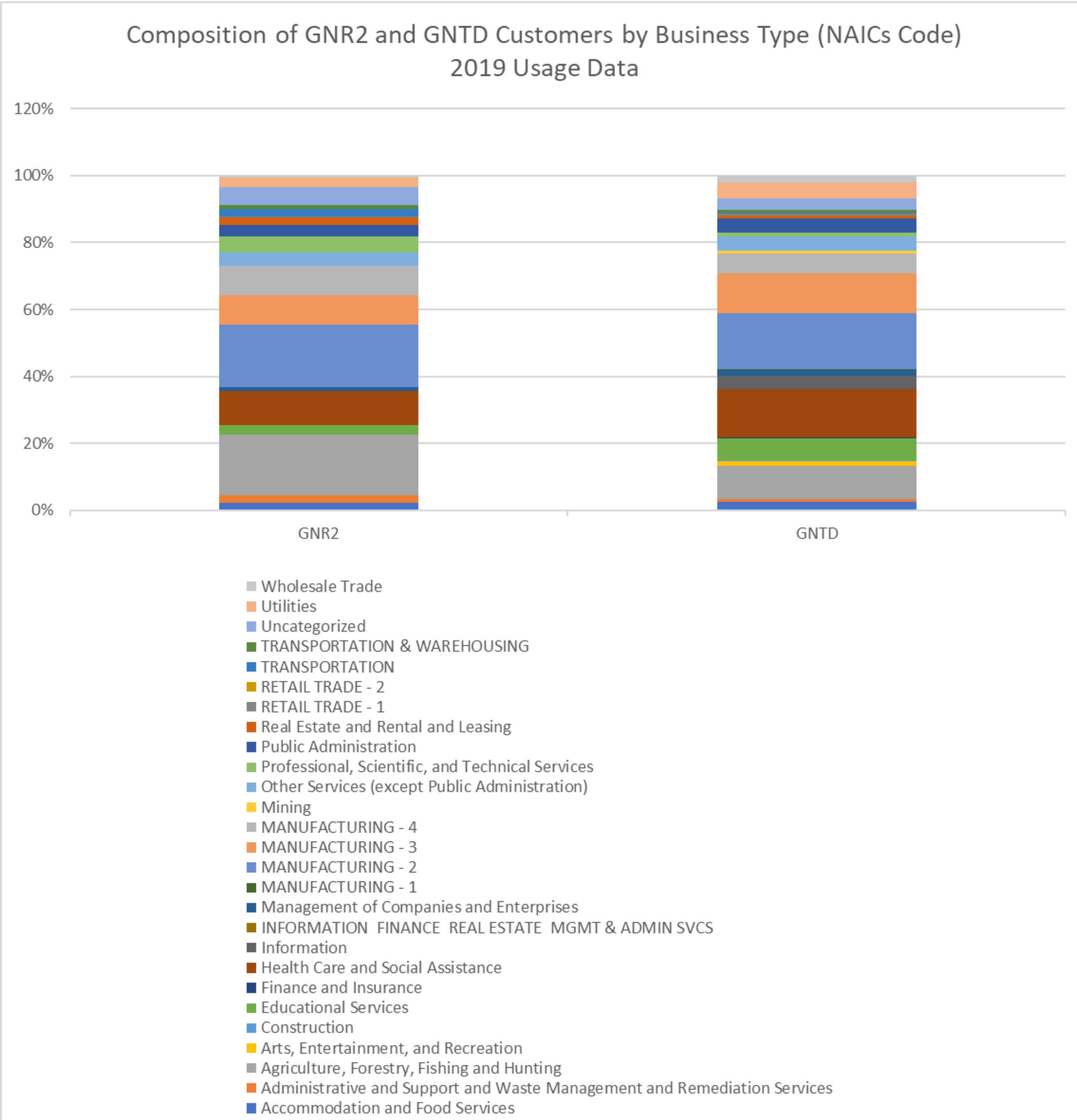
A 25 PG&E partially agrees with TURN's observation. Specifically, PG&E agrees that the use of the Variance function applied to daily usage by season to further segment the Big 3 analysis into the specific end-user customer classes may be premature and in need of additional analysis and refinement before being further considered and implemented. However, PG&E still believes that some level of differentiation between customers classes beyond the Big 3 is necessary to reflect more fairly the cost causation of the Inventory Management service. As an example, if PG&E were to base the allocations solely on the Big 3, under PG&E's proposed methodology to allocate inter- and intra-day imbalances on a 36/64 basis, the large commercial class (schedule GNR2) being included with the core segment would receive an allocation of 50 percent; whereas, the industrial distribution class (schedule GNTD) being included in the industrial segment would receive an allocation of 12.4 percent.[46] Even under TURN's proposal to allocate inter- and intra-day imbalances on a 50/50 basis as describe above, the large commercial class would receive an allocation of 45 percent whereas the industrial distribution class would receive an allocation of 15.7 percent.[47] As Figure 6-1 below illustrates, the types of customers taking service under the GNR2 and GNTD schedules, and presumably therefore, their load profiles and use of inventory management service, are similar.

---

46 PG&E Errata Testimony (Aug. 18, 2022), p. 6-18, Table 6-4.

47 *Ibid*.

FIGURE 6-1
COMPOSITION OF GNR2 AND GNTD CUSTOMERS BY BUSINESS TYPE (NAICs CODE) USAGE DATA



Q 26 What is TURN's recommendation?

A 26 TURN recommends that:

> …[n]o further differentiation among the three large segments should be attempted at this time, absent the availability of more comprehensive data.[48]

Q 27 Do you agree with TURN's recommendation?

A 27 No. As discussed above in Q&A 14 and 15 and with additional consideration of Core NGV and Wholesale[49] segments, PG&E does not agree that using the Big 3 results as is without further adjustments by ultimate end-user customer class is appropriate or fair in reasonable reflection of cost of service for the Inventory Management services. TURN's proposal to limit PG&E's differentiation between customer segments to the three large segments should be rejected.

Q 28 Does PG&E suggest an alternate proposal?

A 28 Yes, PG&E proposes to allocate inventory management costs based on the three broad customer segments (Core, Electric Generation and Industrial) as recommended by TURN,[50] but to then adjust the allocations and resulting rates to reflect more closely the usage profiles of certain classes based on the analysis of the three broad customer segments using the methodology described below.

Q 29 Does PG&E propose continuing to use the variance calculation as originally proposed to make these adjustments.

A 29 No. PG&E proposes to use the cost allocation data and resulting rates derived from the three broad customer segments and the average throughput forecast for the rate case period (2023-2026) to calculate the further segmented inventory management rates as follows:

- Set the residential and small commercial rates equal to the results of the Big 3 study;
- Average the large commercial, core NGV, noncore NGV and all Industrial (Distribution, Transmission and Backbone) classes;

---

48 TURN Prepared Testimony, p. 46, lines 4-6.

49 PG&E's wholesale customers provide service to customers who are almost equivalent to PG&E Core Customers. PG&E Tariff, Sheet 2, allows existing Wholesale Customers a one-time option to "subscribe, on behalf of their core Customers, for firm capacity on the Redwood to on-system and Baja to on-system paths…" This capacity is only offered for the core portion of the Customer's load, <G-WSL, Gas Transportation Service to Wholesale/Resale Customers> (as of Sept. 26, 2022).

50 TURN Prepared Testimony, p. 46, lines 1-4.

- Average Electric Generation (Transmission and Backbone) with Cogen;
- Set Wholesale equal to the average residential, small, and large commercial rate; and
- Iterate through the above steps until the final rates recover the proposed revenue requirement.

Q 30 Does PG&E believe that its alternate proposal presented here would result in a more fair allocation of inventory management costs relative to TURN's proposal to limit the differentiation between customer segments to the Big 3?

A 30 Yes. As described in PG&E's August 18, 2022 Errata Testimony[51] and in prior Q&A's in this rebuttal testimony, PG&E's analysis indicates that customer classes within each of the Big 3 broad segments can have different levels of usage variability. PG&E's alternate proposal provides further differentiation in recognition of these differences but without using the Variance proxy, which use TURN argues is premature.

Q 31 Has PG&E calculated these proposed rates?

A 31 Yes. The table below shows PG&E's revised rates further segmenting the inventory management allocation as described in Q&A 29, as compared to the rates resulting from TURN's recommendation to limit the analysis to using only the Big 3 results without further adjustment.[52]

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[51] PG&E Errata Testimony (Aug. 18, 2022), Section F.2.e., p. 6-17, line 12 to p. 6-23, Table 6-12.

[52] Rates are based on the rates filed in PG&E's Errata Testimony (Aug. 18, 2022), p. 6-23, Table 6-12.

TABLE 6-1
REVISED INVENTORY MANAGEMENT RATES

Line No.	Customer Class	PG&E August 18 Errata	PG&E Revised Proposal	TURN Proposal[a]	Difference: PG&E Revised versus TURN
1	Residential/Small Commercial	$0.0168	$0.0167	$0.0162	$0.0005
2	Large Commercial/Core NGV	$0.0011	$0.0040	$0.0162	$(0.0122)
3	Industrial D	$0.0011	$0.0040	$0.0042	$(0.0002)
4	Industrial BB/T and NGV-4	$0.0060	$0.0040	$0.0042	$(0.0002)
5	EG-T	$0.0189	$0.0197	$0.0276	$(0.0079)
6	EG-BB	$0.0178	$0.0197	$0.0276	$(0.0079)
7	Cogen	$0.0189	$0.0197	$0.0276	$(0.0079)
8	Wholesale	$0.0162	$0.0164	$0.0042	$0.0122

(a) These rates do not reflect TURN's proposal, described in section 2 above, to use a 50/50 weighting between Inter- and Intra-day imbalances to determine the inventory management cost allocators.

3) Calpine's Objection to Moving Inter-Day Inventory Management Costs Out of Backbone Rates Should Be Rejected.

Q 32 What is Calpine's criticism of PG&E's proposal to recover Inventory Management costs in end-user rates? Please describe.

A 32 Calpine opposes moving inter-day Inventory Management costs out of backbone rates where they are currently recovered.[53] To distinguish the opposition, Calpine does not dispute PG&E's proposal to move *intra*-day Inventory Management cost recovery into end-user transportation rates.[54]

Q 33 What is Calpine's rational for opposing moving inter-day Inventory Management costs out of backbone rates?

A 33 Calpine argues[55] that all shippers of gas on PG&E's systems receive the same inter-day balancing service, and for this reason they all should pay the same price. All shippers benefit to some degree from inter-day balancing, and have the ability to use as much or as little of the inter-day balances as they want, with no extra charges, so long as they remain in compliance with the applicable tariff. Moving the allocation to end-use transportation would

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53 Calpine Prepared Testimony, p. 23, line 21.

54 *Id.* at p. 24, lines 23-26.

55 *Id.* at p. 23, line 21 to p. 24, line 21.

penalize particularly core and EG customers who made greater use of available tolerances than other market segments, according to Calpine.[56]

As additional support for its position, Calpine states that several shippers on PG&E's system are not end-use customers, but are gas suppliers or marketers who sell gas. Calpine believes end-users have little control over the balancing performance of these supplier and agents.[57]

Q 34 Do you agree with Calpine's criticism?

A 34 No. Intra-day and Inter-day fluctuation in demand by end-user customer class are both substantially driven by temperature variation, which does not impact all end-user customer classes equally. This compares to customer classes with usage that is dominated by being driven to support a process with generally flat usage hour-by-hour and day-by-day. These differential behaviors drive cost-causation. To recover intra-day balancing but not inter-day balancing in end-use transportation rates would reflect an incomplete price signal and cost recovery. With the increased cost of this service, as discussed in PG&E's testimony,[58] recovering costs from customer classes which do not need nor cause a service would be endorsing cross-subsidization without a clear societal rationale.

Q 35 What is Calpine's recommendation?

A 35 Calpine proposes that all shippers should continue to pay the same Inventory Management rate, as part of backbone rates, for inter-day balancing services.[59]

Q 36 Do you agree with Calpine's recommendation?

A 36 No, for the rationale provided in PG&E's testimony[60] and above, PG&E proposes that both inter-day and intra-day Inventory Management services be recovered in end-use transportation rates with differentiation by customer class. Additionally, as shown in Table 6-2 below, the allocation between

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56 *Id.* at p. 23, line 21 to p. 24, line 5.

57 *Id.* at p. 24, lines 7-21. PG&E interprets this to mean that end-users have little control over how their procurement supplier manages daily gas flow into PG&E's system from interstate and/or storage.

58 PG&E Errata Testimony (Aug. 18, 2022), p. 6-16, lines 12-24.

59 Calpine Prepared Testimony, p. 23, line 21.

60 PG&E Errata Testimony (Aug. 18, 2022), Section F.2.e., p. 6-17, line 12 to p. 6-22, line 16.

segments based on inter-day imbalances—which Calpine proposes—continues to be recovered in backbone rates (Table 6-2, line 3), showing a lower contribution-to-cost causation by the core segment, relative to the Industrial and EG segments. This is true, even taking into account Calpine's proposal to adjust PG&E's allocations by the forecasted throughput (Table 6-2, line 4). By excluding inter-day imbalances in the allocation calculation, core experiences a much higher allocation than if inter-day imbalances were included in the allocation calculation (Table 6-2, lines 5 and 6, compared to Table 6-2, lines 1 and 2, respectively). By leaving recovery of the portion of inventory management costs attributed to inter-day imbalances in backbone rates, (i.e., status quo) core will effectively be subsidizing the EG and Industrial classes, as the current allocation is essentially an equal cents allocation.

TABLE 6-2
INVENTORY MANAGEMENT COST ALLOCATION SCENARIOS

Line No.	Imbalance Type	EG	Industrial	Core
1	Intra-Day	33.2%	3.9%	62.8%
2	Intra-Day – Throughput Adjusted (Calpine Proposal)	25.5%	5.0%	69.6%
3	Inter-Day	45.3%	27.4%	27.3%
4	Inter-Day – Throughput Adjusted	33.9%	29.5%	32.5%
5	Weighted 36% Inter-Day, 64% Intra-Day	37.6%	12.4%	50.0%
6	Weighted 36% Inter-Day, 64% Intra-Day – Throughput Adjusted	28.3%	13.3%	57.0%

Note: Figures are from Calpine Workpaper "Tables 4-8 – Revised Imbalance Forecast and IM Rates.xlsb" provided in response to PG&E Data Request 001, dated 8/16/22, in Attachment F at the end of this chapter.

4) PG&E's Revised Inventory Management Proposal Should be Adopted, In Order to Address Calpine's Concern Regarding the Use of Historical Data to Determine the Allocation of Costs Between the Big 3 Customer Segments

Q 37 Calpine states that "PG&E's allocation of intra-day [inventory management] costs … is based on historical data [which] shows a very different mix of throughput among [the three] market segments" (Core, Electric Generation and Industrial) than the throughput forecasts for this CARD case. Instead of reliance on historical data, "the adopted throughput forecast should be the basis for the allocation of [Inventory Management] costs."[61] Do you agree?

A 37 Yes. Conceptually, PG&E agrees that an enhanced level of precision in Inventory Management cost allocation would result from an adjustment of the historic shares of responsibility to better reflect the rate case period forecast of usage by end-user customer class.

Q 38 Do you agree with Calpine's recommendation to adjust the imbalances "based on the expected change in throughput from recorded 2020 volumes to the 2023-2026 throughput forecast for this case?"[62]

A 38 Yes, subject to the adjustment described below.

Q 39 Does PG&E propose any changes to how Calpine made their proposed adjustment?

A 39 Yes, PG&E would base its adjustment—by end-user Big 3 segment—on the expected change in throughput from the *average* of recorded 2016-2020 volumes to the 2023-2026 throughput forecast for this case, instead of just using recorded 2020 volumes, as Calpine has done.

Q 40 Why does PG&E propose to use an average of recorded volumes rather than a single year?

A 40 PG&E proposes to use an average of recorded volumes to align with the recorded imbalance data. Alignment is important because the underlying analysis that established the Big 3 allocation is based on the five years of recorded imbalance data for the period 2016-2020. Therefore, any adjustment should also use the same five years of total recorded throughput. Additionally, using an average over multiple years can help to smooth out any year-to-year anomalies.

5) Based on Parties' Direct Testimony, PG&E's Recommends Four Adjustments to Its Proposed Inventory Management Allocation

Q 41 What is PG&E's recommendation for the proposal to recover Inventory Management costs in end-user rates?

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61 Calpine Prepared Testimony, p. 25, lines 9-17.

62 *Id.* at p. 26, lines 8-10.

A 41 As discussed in Section C.1.a., PG&E disagrees with SBUA's recommendation to continue recovering Inventory Management in backbone rates per the status quo, TURN's recommendation to not further differentiate among the three large customer segments (Core, Electric Generation and Industrial), and Calpine's recommendation that inter-day Inventory Management costs remain in backbone rates where they are currently recovered. PG&E agrees with TURN's recommendation for using 50/50 weighting, and partially agrees with Calpine's proposal to adjust imbalances based upon the changes in recorded to forecast throughput.

PG&E recommends:

- Using a 50/50 weighting between Inter- and Intra-day imbalances rather than a 37/63 weighting;
- Further dividing the three large customer analytical segments into the following end-use customer classes:
  - Residential and Small Commercial;
  - Commercial/Industrial;
  - EG-D/T/BB;
  - Wholesale;
- Moving the recovery of both inter- and intra-day Inventory Management costs into end-user rates as initially proposed; and
- Adjusting the inter- and intra-day imbalances based on the expected change in throughput from average recorded 2016-2020 volumes to the 2023-2026 throughput forecast for this case.

Q 42 Has PG&E calculated revised inventory management rate components inclusive of the recommendations listed above?

A 42 Yes, the revised inventory management rate components are provided in the table below.

TABLE 6-3
PG&E'S REVISED INVENTORY MANAGEMENT RATES

Line No.	Customer Class	PG&E Corrected Revised Proposal	PG&E Proposed August 18, 2022 Errata	Difference
1	Residential/Small Commercial	$0.0165	$0.0168	$(0.0003)
2	Large Commercial/Core NGV	$0.0043	$0.0011	$0.0032
3	Industrial D	$0.0043	$0.0011	$0.0032
4	Industrial T/BB, and NGV-4	$0.0043	$0.0060	$(0.0017)
5	EG-D/T	$0.0198	$0.0189	$0.0009
6	EG-BB	$0.0198	$0.0178	$0.0020
7	Cogen	$0.0198	$0.0189	$0.0009
8	Wholesale	$0.0161	$0.0162	$(0.0001)

Note: These rates are based on the throughput forecast as proposed by PG&E in Chapters 2A and 2B of its August 18, 2022 Errata Testimony. Any changes in throughput forecast may affect the outcome of the various proposals incorporated herein and thus the rates produced in this table. These rates do not include the effect of the revised functional storage cost allocation shown in Table 6-4.

2. PG&E's Response to Parties' General Criticisms Regarding the Design of Market Responsive EG-LT Rates

Q 43 What is PG&E's proposal regarding EG-LT rate design? Please describe.

A 43 PG&E proposes to continue the single average volumetric LT rate for all core classes and a single average volumetric LT rate for all noncore and wholesale customer classes. PG&E's proposal is more fully discussed in PG&E's prepared testimony.[63]

PG&E's conclusion to maintain its status quo EG-LT rate design is based on its analysis of how a new EL-GT rate design could impact net EG gas throughput compared to the status quo rate design.[64] The full analysis is presented in Chapter 5 of PG&E's prepared testimony. The rate design analyzed was comprised of a high fixed reservation charge and a low volumetric rate. The analytical results showed conflicting indications whether a rate design with the described reservations and volumetric components benefitted all EG customers' gas throughput on the PG&E

63 PG&E Errata Testimony (Aug. 18, 2022), p. 6-12, lines 2-14.

64 *Id.* at p. 5-1, lines 6-12.

system.[65] The analytical results pointed towards a potential increase in net EG throughput, but did not provide conclusive results.[66]

Q 44 Do parties have criticisms of PG&E's conclusion to maintain the currently adopted market responsive EG-LT rate design based on the analysis detailed by PG&E in Chapter 5 of its Prepared Testimony? Please describe.

A 44 Yes, Moss Landing, NCGC and TURN take issue with PG&E's decision to not propose an alternate EG-LT rate with a fixed charge component.

Q 45 Does Moss Landing have an alternate recommendation to PG&E's volumetric EG-LT rate? Please describe.

A 45 Yes. Moss Landing recommends that:

> [T]he Commission should continue to allow EG-LT customers to choose a rate structure that combines a fixed reservation charge with a volumetric rate [and] should also authorize a variation of this rate structure that fixes the volumetric rate for the period covered by this rate case, or at least for each year of the rate case period.[67]

Moss Landing provided an example of it structure for its proposal[68] and describes its proposal in more detail in response to PG&E's data request attached.[69]

Q 46 Does NCGC have an alternate recommendation to PG&E's volumetric EG-LT rate? Please describe.

A 46 Yes, NCGC proposes a rate design that allows customers:

> …the option of remaining either on the all-volumetric rate proposed by PG&E, assuming it is approved by the Commission, or to convert a portion of the customer's specific LT related revenue requirement to a fixed payment.[70]

Q 47 What portion of the EG-LT rate does NCGC propose be collected in a fixed rate component?

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65 *Id.* at p. 5-1, lines 19-23.

66 *Id.* at p. 5-13, lines 13-16.

67 MLPC-01, p. 3, lines 10-16.

68 *Id.* at p. 6, line 13 to p. 8, line 11.

69 MLPC Response to PG&E Data Request, No. 2, A.21-09-018, dated 09/07/2022, in Attachment C at the end of this chapter.

70 NCGC-1, p. 13, lines 21-27.

A 47 NCGC proposes that 100 percent of the Local Transmission and NCA-LT Cost Subaccount be collected in a fixed rate component.

Q 48 Does TURN have an alternate proposal to PG&E's volumetric EG-LT rate? Please describe.

A 48 Yes, TURN proposes that the Commission:

> …[a]dopt a fixed/variable rate design as the standard for the entire EG-LT customer group, using the same general methodology employed by PG&E when it provided such rates to a subset of EG-LT customers on a negotiated basis only.[71]

Q 49 How does PG&E respond to these recommendations in general?

A 49 PG&E disagrees that an EG-LT rate consisting of a fixed charge rate component should be part of a tariff offering, and proposes to continue the currently adopted all volumetric rate design.

Q 50 Why does PG&E disagree with proposals to provide an EG-LT fixed charge rate design as a tariff option?

A 50 As described in Chapter 5 of PG&E's Opening Testimony, and further discussed in Chapter 5 of this Rebuttal testimony, PG&E analyzed whether a rate design with a high reservation (fixed) charge and a low volumetric rate would impact EG-LT gas throughput.[72] PG&E continues to conclude that the results of the analysis are insufficient to warrant any change in the currently adopted rate design.

Q 51 Does PG&E have any concerns with specific proposals made by any party? Please describe.

A 51 PG&E has concerns regarding Moss Landing's preference for a:

> …structure that incorporated a fixed volumetric rate to recover the portion of a customer's revenue responsibility that is currently recovered by a variable volumetric rate in the negotiated rate structure [to be trued-up, ideally, at the end of the rate case cycle or] [i]f a more frequent adjustment is needed, the true-up could occur at the end of each calendar year, and the fixed volumetric rate for the following year would be adjusted for overcollections or undercollections.[73]

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71 TURN Prepared Testimony, p. 2, lines 24-27.

72 This analysis is described in detail in PG&E Errata Testimony (Aug. 18, 2022), Ch. 5.

73 MLPC-01, p. 6, lines 1-12.

Q 52 What are PG&E's concerns with Moss Landing's proposal for a fixed volumetric rate?

A 52 PG&E's main concern with this aspect of Moss Landing's proposal is that the true-up described by Moss Landing would be extremely complicated to administer. It would require that PG&E track, on a customer-specific basis, for each power plant taking this alternate rate option, for each transportation rate change, the over- or undercollection for each rate component.

Q 53 Does PG&E have additional concerns regarding any party's proposal for an EG-LT rate with a fixed charge?

A 53 Yes, PG&E has additional concerns that are addressed in Chapter 9 of this Rebuttal Testimony.

Q 54 Do any parties agree with or remain silent on PG&E's proposal to retain the currently adopted EG-LT rate design methodology?

A 54 Yes. SBUA states the PG&E's:

> …local transmission rate design proposals are acceptable and should be adopted [and that] a manipulation (and thereby subsidization) of these [local electric] generators through gas rates is inappropriate.[74]

Calpine states that it supports the continuation of the existing EG rate design and notes that it will:

> …respond in rebuttal to any proposals to revise the structure of the GT&S transportation rates applicable to EG customers.[75]

Indicated Shippers and Citadel and Tourmaline are silent on EG-LT rate design.

3. PG&E's Response to TURN's General Criticisms Regarding the Functional Allocation of Storage Costs

Q 55 What is PG&E's proposal regarding the functional allocation of storage costs? Please describe.

A 55 Similar to PG&E's allocation of costs between the three storage services (core firm, inventory management and reserve capacity), PG&E allocates the storage cost of service to the three storage functions (inventory, injection and withdrawl) based on the share of annual injection, inventory and

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74 SBUA Prepared Testimony, pp. 14-15.

75 Calpine Prepared Testimony, p. 28, lines 3-7.

withdrawal capacity assigned in PG&E's GRC 1 for the 2023-2026 rate case period.[76]

Q 56 Do parties have criticisms about PG&E's proposal regarding the functional allocation of storage costs? Please describe. Which parties commented on the functional allocation of storage costs?

A 56 Yes one party, TURN, has criticized PG&E's proposal regarding the functional allocation of storage costs. TURN's initial comment is that:

> [T]he pro rata share approach is generally workable, [because] it assigns the costs of the three storage functions to the three services that utilize them, in proportion to the capacity assigned….[77]

However, TURN questions the higher allocation of three times as many costs to withdrawal services than to injection services. It states the allocation of costs to injection is too low at 25.3 percent, while costs allocated to withdrawal is too high at 71 percent. It states PG&E has not provided any cost study that would support its allocation across the three services.[78]

Q 57 On what basis does TURN question the allocations?

A 57 TURN states that, "given the need for expensive compression facilities in order to inject gas into the field," it believes that injection should cost more than withdrawal.[79]

Q 58 Does TURN cite any additional evidence to support its claim regarding the cost of injection relative to withdrawal?

A 58 Yes. TURN cites to Southern California Gas Company's (SoCalGas) last cost allocation proceeding, A.18-07-024, which showed a resulting allocation of injection being "70% higher than the allocation to withdrawal."[80] Based on testimony presented in SoCalGas' proceeding, TURN identified that:

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76 PG&E Errata Testimony (Aug. 18, 2022) p. 6-13, lines 10-15 and Confidential Workpaper 7 of 10.

77 TURN Prepared Testimony, p. 36, lines 19-21.

78 *Id.* at p. 37 lines 28-31.

79 *Id.* at p. 37, lines 28-30.

80 *Id.* at p. 38, lines 1-6.

> [T]he entire cost of the compression facilities was allocated to the injection function, with the result that the injection received the highest allocation of the three functions….[81]

Q 59 Has PG&E performed a study similar to SoCalGas' study?

A 59 No, not to my knowledge.

Q 60 Do you agree with TURN's criticism?

A 60 Yes. PG&E believes TURN's position is reasonable in questioning the relationship between the relative cost of these two services, injection and withdrawal.

Q 61 What is TURN's recommendation?

A 61 TURN recommends that injection and withdrawal be allocated "an equal percentage share (48.15%) of total storage costs."[82]

Q 62 Does TURN recommend that the 48.15 percent of the storage costs remain static throughout the rate case period?

A 62 No. In response to PG&E's data request TURN suggested that [t]he percentage should change with changes in capacity from year to year," but that the allocations between injection and withdrawal should remain equal.[83]

Q 63 Do you agree with TURN's recommendation?

A 63 Yes, PG&E agrees that, for this 2023 CARD proceeding, in the absence of its own cost study and given the analysis TURN cites from SoCalGas,[84] it is reasonable to assign at this time for the 2023-2026 rate case period an equal share of storage costs to injection and withdrawal functions based on the capacities adopted in PG&E's GRC 1.[85]

Based on the modifications agreed to in this rebuttal testimony, and subject to the capacities ultimately adopted in PG&E's GRC 1, PG&E believes an appropriate functional Storage Cost allocation is:

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81 *Id.* at p. 38, lines 1-6.

82 *Id.* at p. 38, lines 7-9.

83 TURN Response to PG&E Data Request, Set Two, Question 2, dated 8/26/2022, in Attachment D at the end of this chapter.

84 TURN Prepared Testimony, p. 38, lines 1-6.

85 PG&E's 2023 GRC Ph 1, Track 1, A.21-06-021, will adopt the storage capacities for the 2023-2026 period that will then be used for ratemaking in the 2023 GT&S CARD decision.

TABLE 6-4
REVISED FUNCTIONAL STORAGE COST ALLOCATION

Line No.	Storage Function	2023	2024	2025	2026
1	Injection	48.24%	48.17%	48.20%	48.20%
2	Inventory	3.52%	3.66%	3.60%	3.60%
3	Withdrawal	48.24%	48.17%	48.20%	48.20%
4	Total Functional Allocation	100.00%	100.00%	100.00%	100.00%

Q 64 What is PG&E's recommendation for allocating storage costs to the three storage functions (injection, inventory and withdrawal)?

A 64 PG&E agrees with TURN's recommendation to allocate an equal share of storage costs to the inventory and withdrawal functions based on the capacities assigned in the GRC 1 for each year of the rate case period.

Q 65 Does PG&E intend to conduct a cost study in its next CARD Application, to more precisely determine the shares of storage costs that the injection and withdrawal functions represent for future rate cases?

A 65 Yes, PG&E intends to conduct a cost study to more precisely determine the shares of storage costs applicable to the injection and withdrawal functions and to use those resulting shares to allocate storage costs in its next CARD application.

Q 66 Did any other parties comment on PG&E's proposal regarding the functional allocation of storage costs?

A 66 No, no other parties comment on PG&E's proposal regarding the cost of storage assigned to CGS firm storage.

4. PG&E's Response to TURN's General Criticisms Regarding the Cost of Storage Assigned to CGS Firm Storage

Q 67 What is PG&E's proposal regarding the cost of storage assigned to CGS Firm Storage? Please describe.

A 67 PG&E allocates the storage cost of service to the three storage functions (core firm, inventory management and reserve capacity) based on the pro rata share of current annual injection, inventory and withdrawal cycling assigned to each service for the 2023-2026 rate case period.[86]

Q 68 In what proceeding are these capacities established?

86 PG&E Errata Testimony (Aug. 18, 2022), p. 6-13, lines 10-15.

A 68 These capacities are assigned in PG&E's GRC I.

Q 69 How does PG&E determine the capacities for each storage function?

A 69 As described in PG&E's 2023 GRC 1, PG&E first establishes the total amount of supply resources needed, including the amount of gas storage withdrawal, to safely operate the system. PG&E then subtracts the operating uses of gas storage (Inventory Management and Reserve Capacity) from the total forecast of PG&E gas storage capacity to determine the amount of gas storage proposed to be held by PG&E's CGS.[87]

Q 70 Do parties have general criticisms about PG&E's assignment of storage costs to CGS Firm Storage? Please describe.

A 70 Yes, TURN criticizes PG&E's method of assigning storage capacities to CGS Core Firm storage stating that, while it is assigned to CGS:

> CGS customers do not 'need' this withdrawal any more than Non-Core or Core-Transport customers do[88] [and that it is] *system reliability needs*, rather than any particular CGS need, that determines the amount of storage that is ultimately 'assigned' to the CGS Firm Storage.[89]

Q 71 Why is TURN's assertion that additional withdrawal capacity was "assigned" to CGS incorrect? *(Sponsoring Witness: James Chen).*

A 71 TURN incorrectly assumes that CGS is being "assigned" excess capacity because TURN failed to recognize in table 7-15 of PG&E's GRC Testimony[90] that the majority of the increase in demand was due to the rise in Core's peak demand. In fact, the entire differential between the adopted 2019 NGSS capacities and those proposed in the 2023 GRC Ph 1 Track 1 for the winter of 2025/2026 are due to core's operational needs. TURN's testimony also does not recognize that the northern and southern path's supply have remained constant in addition to the increase of Core's demand. With Non-Core demand remaining primarily neutral, the incremental capacity needed to meet demand must be provided within the Redwood and Baja path constraints.

Q 72 TURN states that:

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[87] A.21-06-021, Exhibit (PG&E-3), p. 7-55, lines 2-8.

[88] TURN Prepared Testimony, p. 41, lines 18-21.

[89] *Id.* at p. 42, lines 1-2.

[90] Table 7-15 of PG&E's GRC 1 Testimony in Attachment G at the end of this chapter.

> [S]ince the assignment of this storage capacity to Core Gas Supply is a matter of operational convenience and does not represent any actual CGS-specific need, CGS customers should not be forced to pay premium PG&E-cost-based prices for that storage when much cheaper alternatives are available in the market from ISPs.[91]

TURN recommends that CGS's direct cost responsibility for the capacity assigned to it:

> …be limited to what it would otherwise pay to obtain that capacity from ISPs, that is, the going market price of storage in Northern California.[92]

How does PG&E respond? *(Sponsoring Witness: James Chen).*

A 72 PG&E disagrees with TURN's recommendation to limit CGS's direct cost responsibility to the going market price of storage in Northern California because, as previously described in Q&A 71 above, TURN's assertion that CGS is being "assigned excess" capacity that it does not need is incorrect. Therefore, TURN's rationale for recommending to limit CGS's cost responsibility is based on an incorrect assumption.

Q 73 Did any other parties comment on PG&E's proposal regarding the cost of storage assigned to CGS firm storage?

A 73 No, no other parties comment on PG&E's proposal regarding the cost of storage assigned to CGS firm storage.

5. PG&E's Response to SBUA's General Criticisms Regarding the CAC for Residential and Small Commercial Classes of Customers

Q 74 What is PG&E's proposal regarding the Customer CAC for residential and small commercial classes of customers? Please describe.

A 74 PG&E proposes to scale the currently adopted CACs, multiplied by the forecast of customers by tier, such that the resulting revenues match the CAC revenue requirement proposed in PG&E's 2023 GRC I, A.21-06-021.[93]

Q 75 Do parties have criticisms about PG&E's proposal regarding the CAC for Residential and Small Commercial Classes of Customers? Please describe.

A 75 Yes, SBUA has two criticisms about PG&E's proposal regarding the CAC for residential and small commercial classes of customers. First, it alleges that

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91 *Id.* at p. 42, lines 3-6.

92 *Id.* at p. 42, lines 10-13.

93 PG&E Errata Testimony (Aug. 18, 2022), p. 6-26, lines 5-8.

PG&E does not propose a specific CAC for small commercial customers. Second, it recommends that CACs be limited for residential and small commercial customer, to limit bill impacts for these sensitive customers.[94]

Q 76 Do you agree with SBUA's recommendation?

A 76 No, PG&E does not agree with SBUA's recommendation, and SBUA's issues are out of scope. CACs for residential and small commercial customers are developed in the GCAP, which PG&E anticipates filing in the latter of either the fourth quarter of 2023, or 90 days after both GRC 1 and GT&S CARD decisions have been released. Accordingly, it is not appropriate for PG&E to take a position in this CARD case regarding the development of residential and small commercial customer CACs or the limiting thereof.

Q 77 What is PG&E's recommendation regarding whether the CAC for residential and small customer classes should be limited?

A 77 PG&E recommends that this issue continue to be addressed in PG&E's next GCAP.

Q 78 Do any other parties comment on PG&E's proposal regarding CACs.

A 78 No, no other parties comment on PG&E's proposal regarding CACs.

D. Conclusion

Q 79 What is PG&E's recommendation for Chapter 6 proposals?

A 79 See Table 6-5 below for a summary of PG&E's Revised Chapter 6 Proposals; proposals which PG&E would not revise are not listed in the table.

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[94] SBUA Prepared Testimony, p. 18.

TABLE 6-5
REVISED CHAPTER 6 PROPOSALS

Line No.	Function	Intervenor	Intervenor Proposal	PG&E Revised Proposal
1	Storage	TURN	Allocate storage costs 50 percent to injection and 50 percent to withdrawal functions	Allocate storage costs 50 percent to injection and 50 percent to withdrawal functions as proposed by TURN
2	Inventory Management	TURN	Refrain from using Variance to further subdivide the allocation of inventory management costs into specific customer classes	Further subdivide the allocation inventory management costs into specific customer classes using forecasted throughput and PG&E's "Big 3" analysis, but not Variance
3	Inventory Management	TURN	Weight Inter- and Intra-Day imbalances on an 50/50 basis	Weight Inter- and Intra-Day imbalances on an 50/50 basis as proposed by TURN
4	Inventory Management	Calpine	Using 2020 historic data, weight historic usage by class to scale to average 2023-2026 forecast usage by class.	Using average of 2016-2020 historic data, weight historic usage by class to scale to average 2023-2026 forecast usage by class.

Q 80 Has PG&E calculated updated illustrative end-user rates incorporating the revised proposals discussed in this testimony.

A 80 Yes, the updated illustrative end-user rates incorporating the revised proposals are provided in Attachment E at the end of this chapter. These rate calculations incorporate only the revised proposals presented in this chapter, and do not include any impact on backbone rates that might result from changes to storage reserve capacity costs collected in backbone rates.[95]

Q 81 Does this conclude your rebuttal testimony?

A 81 Yes it does.

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95 TURN's proposal to allocate storage costs 50 percent to injection and 50 percent to withdrawal functions impacts the storage cost allocation between inventory management, reserve capacity and core firm storage. The change in reserve capacity costs collected in backbone rates can impact the calculation of certain backbone rate inputs depending upon the magnitude of the change; however, PG&E has not extended its analysis to the calculation of backbone rate inputs at this time.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT A

PG&E ERRATA TO PG&E ERRATA TESTIMONY

(AUG. 18, 2022), P. 6-15, LINES 11-17

a. Reserve Capacity Service

Storage costs allocated to Reserve Capacity are included in all backbone transmission rates as continued from the adoption of the NGSS.

2. Inventory Management Service

a. Summary

PG&E proposes to move the recovery of Inventory Management from its unbundled backbone transmission rates to its end-use transportation rates where it can differentiate cost recovery by customer class in a manner reflective of cost causation and utilization of the service. Costs associated with Inventory Management and allocated to Core customers will be recovered, on an equal cents per therm basis, through the Core Cost Subaccount of the Core Fixed Cost Account (CFCA). ~~Costs~~ Over- or undercollections associated with Inventory Management and allocated to Noncore customers will be recovered, on an equal cents per therm basis, through the Noncore Subaccount of the Noncore Customer Class Charge Account (NCA).

b. Background

Inventory Management Service (Inventory Management) was established in the PG&E's NGSS adopted in the 2019 GT&S Rate Case.[34] Inventory Management uses a portion of PG&E's storage capacity to maintain safe and reliable pressure and gas service on an hourly and daily basis. This service is necessary as gas flows into PG&E's gas transmission system at the Oregon and Arizona borders generally on a steady basis, hour-to-hour and day-to-day. The consumption of gas at the burner tip is generally not steady. It fluctuates significantly, mostly related to weather, but also to availability of renewable generation and whether it is a weekday or weekend/holiday, impacting demand for not only natural gas but for electricity generated by natural gas. The cost recovery of Inventory Management as adopted in the NGSS and 2019 GT&S Rate Case is as

[34] D.19-09-025, p. 321, OP 8.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT B

SBUA RESPONSE TO PG&E DATA REQUESTS, SET ONE,

QUESTION 6 (9/14/2022)

GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
(A.21-06-021)
SMALL BUSINESS UTILITY ADVOCATES
RESPONSE TO PG&E DATA REQUESTS, SET ONE

TO:	Chris McRoberts Email: chris.mcroberts@pge.com. Taylor Storer Email: T8SF@pge.com
FROM:	Michael Brown, on behalf of Small Business Utility Advocates Email: michael@mbrownlaw.net; Jennifer Weberski Email: jennifer@utilityadvocates.org Luke May Email: luke@utilityadvocates.org
DATE SENT:	August 28, 2022
DATE DUE:	September 14, 2022 (by agreement with PG&E)

DATA RESPONSES

Q 1: At page 5 of SBUA Testimony, SBUA testifies that it "believe(s) that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."

> **a) Please provide a detailed explanation of all reasons supporting SBUA's conclusion "that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."**
>
> **b) Please provide all calculations, data sources, assumptions, and documents that support SBUA's conclusion "that PG&E is forecasting a more precipitous decline in electric generation from natural gas than is realistic."**

Response:

a) PG&E appears to forecast a steep decline in electric generation from natural gas (from recorded 2020 baseline levels) during the 2023-2026 period, as detailed below in Table 2A-1:

TABLE 2A-1
AVERAGE-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED
(MDTH/D)

Line No.		2020 Recorded	2023 Forecast	2024 Forecast[a]	2025 Forecast	2026 Forecast
1	Electric Generation					
2	Non-market-responsive EG	163	155	156	155	155
3	Market-responsive EG	654	319	316	342	371
4	*Local Transmission*	*287*	*60*	*58*	*59*	*60*
5	*Backbone-only*	*367*	*259*	*258*	*284*	*312*
6	Total Electric Generation	817	474	472	497	527

(a) Since 2024 is a leap year, calculating an annual average value from monthly data results in throughput that is slightly higher than in other years.

2020 Total Electricity System Power

Contact

Michael Nyberg
Energy Assessments Division
916-931-9477

Depending on browser width, scrolling of table may be necessary. Scroll bar is at bottom of table.

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	Total Imports (GWh)	Percent of Imports	Total California Energy Mix (GWh)	Total Califor Power Mix
Coal	317	0.17%	194	6,963	7,157	8.76%	7,474	2.74%
Natural Gas	92,298	48.35%	70	8,654	8,724	10.68%	101,022	37.06%
Oil	30	0.02%	-	-	0	0.00%	30	0.01%
Other (Waste Heat / Petroleum Coke)	384	0.20%	125	9	134	0.16%	518	0.19%
Nuclear	16,280	8.53%	672	8,481	9,154	11.21%	25,434	9.33%
Large Hydro	17,938	9.40%	14,078	1,259	15,337	18.78%	33,275	12.21%
Unspecified	-	0.00%	12,870	1,745	14,615	17.90%	14,615	5.36%
Total Non-Renewables and Unspecified Energy	127,248	66.65%	28,009	27,111	55,120	67.50%	182,368	66.91%
Biomass	5,680	2.97%	975	25	1,000	1.22%	6,679	2.45%
Geothermal	11,345	5.94%	166	1,825	1,991	2.44%	13,336	4.89%
Small Hydro	3,476	1.82%	320	2	322	0.39%	3,798	1.39%
Solar	29,456	15.43%	284	6,312	6,596	8.08%	36,052	13.23%
Wind	13,708	7.18%	11,438	5,197	16,635	20.37%	30,343	11.13%
Total Renewables	63,665	33.35%	13,184	13,359	26,543	32.50%	90,208	33.09%
Total System Energy	190,913	100.00%	41,193	40,471	81,663	100.00%	272,576	100.00%

2021 Total System Electric Generation

Contact

Michael Nyberg
Energy Assessments Division

2020 Total System Electric Generation and previous years

Depending on browser width, scrolling of table may be necessary. Scroll bar is at bottom of table.

Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	Total Imports (GWh)	Percent of Imports	Total California Energy Mix (GWh)	Total California Power Mix
Coal	303	0.2%	181	7,788	7,969	9.5%	8,272	3.0%
Natural Gas	97,431	50.2%	45	7,880	7,925	9.5%	105,356	37.9%
Oil	37	0.0%	-	-	-	0.0%	37	0.0%
Other (Waste Heat/Petroleum Coke)	382	0.2%	68	15	83	0.1%	465	0.2%
Nuclear	16,477	8.5%	524	8,756	9,281	11.1%	25,758	9.3%
Large Hydro	12,036	6.2%	12,042	1,578	13,620	16.3%	25,656	9.2%
Unspecified	-	0.0%	8,156	10,731	18,887	22.6%	18,887	6.8%
Total Thermal and Non-Renewables	**126,666**	**65.2%**	**21,017**	**36,748**	**57,764**	**69.1%**	**184,431**	**66.4%**
Biomass	5,381	2.8%	864	26	890	1.1%	6,271	2.3%
Geothermal	11,116	5.7%	192	1,906	2,098	2.5%	13,214	4.8%
Small Hydro	2,531	1.3%	304	1	304	0.4%	2,835	1.0%
Solar	33,260	17.1%	220	5,979	6,199	7.4%	39,458	14.2%
Wind	15,173	7.8%	9,976	6,405	16,381	19.6%	31,555	11.4%
Total Renewables	**67,461**	**34.8%**	**11,555**	**14,317**	**25,872**	**30.9%**	**93,333**	**33.6%**
Total System Energy	**194,127**	**100.0%**	**32,572**	**51,064**	**83,636**	**100.0%**	**277,764**	**100.0%**

As shown by the charts above,[1] natural gas and solar generation increased from 2020 to 2021, on a percent basis, as reported by the CEC. Expert Michael Brown contends that this trend is likely to accelerate (or remain stable) in the coming years; in particular, solar generation will increase – due to favorable economics, and legislative mandates. Natural gas is a stable source of electricity, which can "back up" solar generation during periods of intermittency. This combination seems to be acceptable in California, and therefore is likely to be used to replace other types of generation.[2]

[1] *Available at*: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation; https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation/2020

[2] See *e.g.*: https://www.npr.org/2022/05/07/1097376890/for-a-brief-moment-calif-fully-powered-itself-with-renewable-energy

Also, other types of generation are being taken offline. This is primarily because: (1) California has decided to decommission Diablo Canyon and SONGS; (2) hydroelectric projects – writ large – are not being expanded, but rather are being decommissioned or made secondary to environmental interests; and (3) coal will eventually be completely phased out in California. Thus, because nuclear and hydro facilities are being decommissioned and because stable "baseload" will be necessary to complement solar generation, we believe that reducing gas usage for electric generation from 817 Million Dekatherms per day (2020) to 472-474 Million Dekatherms per day (2023 & 2024 forecast) presents risks for small business ratepayers.

b) Please see response to (a) above. Mr. Brown did not perform any additional independent calculations.

Q 2: At page 6 of SBUA Testimony, SBUA testifies that "PG&E's application does not comply with Commission Decision 19-09-025, ordering paragraph 86."

a) Please confirm that PG&E provided a cold year electric generation demand forecast in its Prepared Testimony, at Chapter 2, Section D and Table 2A-6.

b) Does SBUA contend that the forecast presented in its Prepared Testimony (at Chapter 2, Section D and Table 2A-6) does not comply with Decision 19-09-025, OP 86?

c) If so, please provide a detailed explanation of the reasons that SBUA's concludes that the PG&E's Prepared Testimony does not comply with the Decision.

d) Please provide SBUA's all calculations, data sources, assumptions, and documents that supports SBUA's conclusion that PG&E did not comply with decision (D) 19-09-025, Ordering Paragraph (OP) 86 to include a forecast of electric generation gas demand using a 1-in-35 cold year scenario.

Response:

a) Table 2A-5 is a cold year electric generation demand forecast. The testimony refers to Table 2A-5, not Table 2A-6. After review of PG&E's testimony, there does not appear to be a "Table 2A-6." For the purposes of this response, SBUA assumes that "2A-6" was a typo.

b) Decision 19-09-025 states that, "Pacific Gas and Electric Company shall provide a separate cold-year forecast of Electric Generation gas demand in its next Gas Storage and Transmission rate case application." While Expert Brown acknowledges that PG&E did provide a cold year electric generation demand forecast, Expert Brown does not believe that Table 2A-5 fulfilled the Commission's intent of the ordering paragraph. The forecast did not serve the purpose of the Commission Order, which was to model an extreme cold weather event. That exercise would help determine the capacity of the natural gas delivery system.

c) As discussed above, while PG&E did provide a forecast, Expert Brown's opinion is that PG&E did not comply with the intent of the Commission's request. PG&E should have used a different methodology in making its cold weather forecast. As noted in SBUA's testimony, we recommend that PG&E use a methodology similar to SEMPRA's 15-year cold year electric generation demand forecast.

Q 3: At page 14 of SBUA Testimony, SBUA testifies, "However, a manipulation (and thereby subsidization) of these generators through gas rates is inappropriate."

a) Does a rate design that incorporates recovery of fixed cost of service in a fixed charge provide a discount?

b) Does SBUA agree that PG&E's local transmission function costs are fixed in nature?

c) Does SBUA agree that PG&E's alternative negotiated fixed charge EGLT rate design-based contracts (PG&E Prepared Testimony, Chapter 5) did not provide a discount to the power plants that chose that option?

d) If SBUA asserts that PG&E's alternative negotiated fixed charge EGLT rate design provides a discount to power plants that chose that option, then explain in detail the discount that these power plants received. Quantify the amount or level of discount these power plants received.

Response:

a) As asked, it is difficult to say whether a rate design that incorporates a fixed cost of service in a fixed charge provides a discount, without further cost of service information or the charge; rate designs that incorporate both a fixed and variable charge may provide either a discount or overcharge, relative to the cost of service. As such the G-EG LT tariff should attempt to recover the exact cost of providing service to customers using that tariff whether it be by fixed or variable charges.

b) Local transmission function costs are fixed in nature with some variability in terms of maintenance costs.

c) – (d). Expert Brown's understanding (based on PG&E's testimony) is that the G-EG LT tariff only recovered 90 percent of the annual revenue requirement. From that information, he deduced that (in general) customers choosing that option would receive a discount. Mr. Brown did not conduct an independent study.

Q 4: At page 17 of SBUA Testimony, SBUA testifies, "PG&E states that wholesale customers exhibit more uniform demand patterns, thereby not necessitating storage." SBUA's footnote refers to See PG&E's Prepared Testimony at page 6-19.

a) Please confirm that the PG&E testimony referred to by SBUA does not refer to or identify wholesale customers, but states, "Off-system customers of PG&E backbone transmission system currently pay for this service in their unbundled backbone rates despite not being end-use customers and not contributing to the imbalances across the hours of the day or days of the month." PG&E Prepared Testimony, p. 6-18, lines 1-4 (August 18, 2022).

b) Confirm that "wholesale customers" are not the same as "off-system" customers.

c) Please confirm that, with regard to wholesale customers, PG&E testified that "Wholesale customers serve almost solely end-use customers classified as core. Therefore, PG&E proposes that wholesale customers pay the Inventory Management rate associated with PG&E's total Core group." PG&E Prepared Testimony, p. 6-22, lines 4-7 (August 18, 2022).

Response:

a. SBUA's testimony refers to page 6-19, lines 3-8, which states: "Core NGV and Large Commercial classes closely mimic the Industrial Distribution class in terms of winter usage …" Expert Brown interprets this statement as meaning that natural gas usage amongst these classes of customers is relatively uniform, and these classes are, therefore, in less need of natural gas storage. The testimony was not referring to wholesale customers / large customers in general, such as large commercial and large industrial customers. SBUA's testimony was not intending to refer to off-system customers, and was not trying to imply that PG&E was referring to off-system customers.

b. Correct - wholesale customers are not the same as off-system customers.

c. SBUA agrees that this is in PG&E's testimony. However, SBUA's testimony was in reference to 6-20; lines 18-21.

Q 5: At page 17 of SBUA Testimony regarding PG&E's proposal to change the recovery of the Inventory Management service, SBUA testifies, "However, PG&E fails to acknowledge the above factors, and likewise does not explain why such a large aggregate change is necessary."

a) Please confirm that PG&E's testimony (PG&E, Errata II, August 18, 2022 Clean, at p. 6-15 to 6-17) provides the rationale for a more cost-based recovery of the Inventory Management cost?

b) Specifically, does SBUA believe that the increase over time in the Inventory Management's revenue requirement and the Gas Planning OIR's discussion of increased volatility of EG demand for natural gas as discussed (both referenced in PG&E's testimony (p. 6-15 and 6-16, August 18, 2022 Errata II Clean) is not an explanation as to why an examination of the class-based causation of inventory management services is warranted?

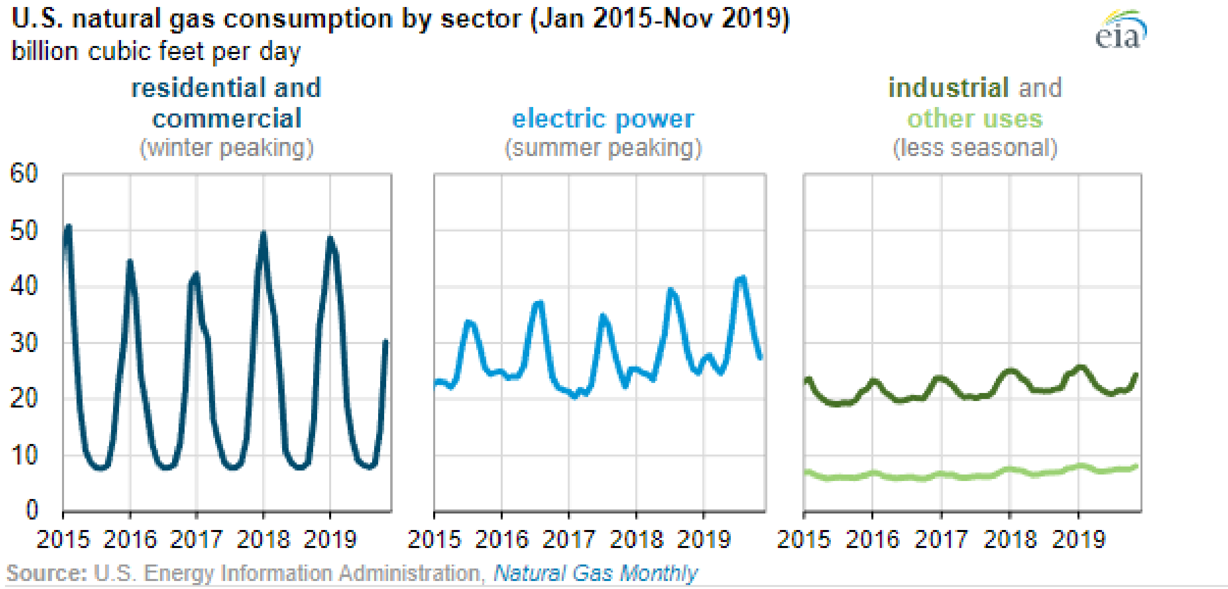
c) Does SBUA acknowledge that large commercial/industrial customers have load profiles that are far more consistent across both summer and winter seasons than profiles of residential/small commercial on one hand and electric generation on the other?

Response:

a) Expert Brown has reviewed PG&E's Errata and confirms that PG&E provided a rationale. The Errata explains why recovery by customer class of increased use of the storage system was warranted on a cost causation basis.

b) PG&E makes reference to the implementation of the Natural Gas Storage Strategy (NGSS) and the 2019 GT&S Rate Case as the reason why Inventory Management Service was established. PG&E now proposes to recover costs based on customer class. Since PG&E does own natural gas storage facilities, the analysis and cost allocation are currently in dispute and up for discussion. PG&E must purchase and maintain cushion gas, as well as maintain its various gas storage and transmission assets. However, it is unclear why small commercial customers and residential customers need to be allocated a large portion of "Inventory Management" costs. PG&E uses daily gas fluctuations as a reason for a large Inventory Management discrepancy amongst customer classes. However, it is unclear what cost these variations are actually causing. PG&E has a fixed asset (natural gas storage) which requires cushion gas and maintenance. So, it is unclear why small commercial customers, as a class, are causing PG&E to incur Inventory Management costs.

   Expert Brown further believes that if PG&E intends to increase its usage of, and rely more heavily upon natural gas storage (as opposed to firm natural gas delivery contracts), then it must consider that small businesses are a smaller user of electricity in the summer time and greater user of natural gas in the winter time.[3]



As far as storage, most electric generators are more interested in securing storage capacity (and using natural gas) during the summer time, when they must generate electricity during the periods of highest demand. If PG&E is going to differentiate between classes, and allocate costs based on class-based causation of inventory management, then small commercial customers should receive a lesser cost allocation.

c) Expert Brown agrees that large commercial/industrial customers generally have more consistent load profiles (both summer and winter seasons) than residential and small commercial customers.

---

[3] See *e.g.* https://www.eia.gov/todayinenergy/detail.php?id=42815

Q 6: At page 17 of SBUA Testimony, SBUA testifies, "Furthermore, natural gas storage is cheaper in the winter months."

a) Please provide all workpapers, studies, analyses, or other documents that support SBUA's conclusion that natural gas storage is cheaper in the winter months.

b) Please provide all workpapers, studies, analyses, or other documents that SBUA's conclusion natural gas storage withdrawals in the summer are complementary to winter withdrawal.

Response subparts a & b:

Expert Brown acknowledges that it is possible that this statement may not be true. However, Expert Brown has prior experience in managing natural gas inventory at natural gas power plants; this experience has demonstrated that, generally, companies purchase gas storage capacity year-round. Like a balloon, they fill up natural gas storage capacity during the winter-time, with any excess gas. Then as summer approaches, they use excess natural gas to run the power plant, in addition to using whatever firm natural gas deliveries are supplied to them. The exact costs of natural gas storage, by season, would vary by demand in the market.

Q 7: At page 17 of SBUA Testimony, SBUA testifies, “the two should compliment each other” when discussing residential vs EG demands for inventory management service.

a) **Does SBUA testimony acknowledge that residential/small commercial usage on the one hand and electric generation on the other hand both have load shapes impacted by variations in temperatures?**

b) **Does PG&E propose roughly similar Inventory Management rate components for the residential/small Commercial/wholesale and electric generation customer classes? (Table 6-12, page 6-23, August 18 filing)?**

c) **Are these PG&E proposed Inventory Management rate components both significantly higher than those proposed for large commercial and industrial customer classes?**

Responses subparts a-c:

a. Yes.

b. Yes. PG&E does propose roughly similar Inventory Management rate components for residential & small commercial/ Wholesale/ and Electric Generation Customer classes in line 3 “Implementation Rates under this proposal 2023”.

c. Please clarify the question and provide the actual cost of inventory management for all customer classes, in order for SBUA to provide an informed response about what the cost of service for each customer class should be.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT C

MOSS LANDING POWER PLANT COMPANY RESPONSE TO

PG&E DATA REQUEST, SET TWO (09/07/2022)

Response of Moss Landing Power Company LLC to
Data Request No. 2 of Pacific Gas and Electric Company
A.21-09-018—GT&S Cost Allocation and Rate Design
September 7, 2022

Request 1: Moss Landing proposes an EG-LT rate consisting of a fixed monthly reservation charge and a fixed volumetric rate that could be trued up either at the end of the rate case cycle or annually at the end of each calendar year. See Prepared Testimony of Eric Wurzbach on behalf of Moss Landing, p. 5 line 9 through p. 6, line 12.

Q 1:

a. Regarding the fixed volumetric portion of Moss Landing's proposed rate, is Moss Landing proposing to only recover the remaining Local Transmission (LT) allocation not recovered in the fixed monthly reservation charge?

b. Or does Moss Landing propose to recover non-LT cost allocations in the proposed fixed volumetric rate as well?

Response: MLPC's proposal is based on the structure of the current negotiated rate agreement between PG&E and MLPC. That structure includes a monthly fixed charge (reservation charge) and a volumetric transmission charge that currently includes a premium above the Backbone Level Rate of Schedule G-EG. MLPC also pays a fixed monthly Customer Access Charge and a volumetric franchise fee surcharge required by Schedule G-SUR.

Please refer to the rate components provided in Chris McRoberts' email of September 1:

	Noncore Transportation Electric Gen D/T
End-Use Transportation:	
Local Transmission	1.8830
Self Generation Incentive Program	0.0000
CPUC Fee	0.0086
AB32 ARB Cost of Implementation Fee	0.0148

AB32 Greenhouse Gas Compliance & Obligation Cost	1.0234
NGSS Transition Costs Recovery	(0.0639)
Balancing Accounts	0.2574
NCA - Local Transmission Cost Subaccount (10)	0.0765
Inventory Management Cost Recovery	0.1886
GT&S Pension	0.0139
Distribution - Annual Average (b)	0.0175
Volumetric Rate - Annual Average	3.4198
CAC - Class Avg Volumetric Equivalent (c)	0.0148
Gas Public Purpose Program Surcharge	0.0000
Total Rate	**3.4347**

Under MLPC's proposal, all of the highlighted rate components identified by PG&E that make up the Volumetric Rate – Annual Averages would be fixed for either the rate case period or annually, subject to true-up at the end of the period. The volumetric transportation charge (designated as Local Transmission in this table) would consist of the tariffed EG-BB volumetric rate (that would also be fixed) and a premium. The specific amount of the premium above the EG-BB volumetric rate would be determined by each customer's election of the level of the fixed monthly reservation charge. The transportation rate component could not be lower than the tariffed EG-BB volumetric rate.

The Customer Access Charge would be a monthly charge and would not be part of the volumetric rate. Some generators would be exempt from the AB32 Greenhouse Gas Compliance & Obligation Cost charge.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT D

TURN RESPONSE TO PG&E DATA REQUEST, SET TWO,

QUESTION 2 (8/26/2022)

PACIFIC GAS AND ELECTRIC COMPANY
GTS Cost Allocation and Rate Design (CARD) 2023
Application 21-09-018
Data Request

To:	The Utility Reform Network		
Recipient:	Michel Peter Florio		
PG&E Data Request No.:	PGE_TURN_002		
PG&E File Name:	GTS-CARD-2023_DR_PGE_TURN_002-Q01-03		
Request Date: August 24, 2022		PG&E Witness:	Chris McRoberts
Response Date: August 26, 2022		PG&E Witness Phone No.:	415-973-4859

INSTRUCTIONS:

PG&E requests this information no later than September 7, 2022. If any of these requests are unclear or otherwise objectionable, please contact Chris McRoberts so we may attempt to resolve any problems.

SUBJECT: FUNCTIONAL ALLOCATION OF PG&E'S STORAGE COSTS

TURN recommends that PG&E's approach to allocating storage costs between injection, inventory and withdrawal be modified "such that injection and withdrawal are allocated an equal percentage share (48.15%) of total storage costs". (TURN p.38, lines 8-9)

Q 1: Please provide TURN's calculation of the 48.15% equal percentage share of injection and withdrawal allocation.

A 1: TURN used PG&E's Chapter 6 Workpaper 7 of 10, in the second tab, "CALC_Apr-Dec 2023," where it can be seen toward the bottom under "Service Percentages" and "Active Scenario," that the withdrawal function is allocated 71.0% of the total cost of storage, injection is allocated 25.3% and remainder is assigned to inventory. 71.0 plus 25.3, divided by two equals 48.15.

Q 2: Does TURN propose that the same percentage (48.15%) be used for all years of the rate case period, or would the percentage change with changes in capacity from year to year?

A 2: The percentage should change with changes in capacity from year to year. TURN only noticed a change in the tab for "CALC_Apr-Dec 2024," but any time the capacity figures change the percentages should change, but our recommendation is that they should remain equal for injection and withdrawal.

Q 3: PG&E has applied its interpretation of TURN's proposal to the storage model workpaper attached to this request.

a. Do PG&E's calculations accurately reflect TURN's proposal?

It is difficult to tell precisely because TURN has been unable to locate a PG&E workpaper for comparison that is identical except for this one change. The yellow-highlighted figures on line 14 appear to correctly implement TURN's proposal to equalize the allocations between the injection and withdrawal functions, but the "Total" percentage columns for each storage service in each year, shown on lines 16-18, do not appear to have been updated to capture the change on line 14. However, it does not appear that those total percentages carry through to the end result, so as far as TURN is able to determine, the overall results are correct.

b. If not, please explain where the implementation of TURN's storage allocation proposal would differ from PG&E's attached calculations.

N/A

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT E

UPDATED ILLUSTRATIVE END-USER RATES INCORPORATING

PG&E'S REVISED PROPOSALS

2023 GAS TRANSMISSION AND STORAGE COST ALLOCATION AND RATE DESIGN CASE
February 23, 2023 Rebuttal Errata
Attachment E Table 6-1
GT&S Revenue Requirement
Including Core and Noncore Revenue Responsibility
($ Thousand)

Line No.		2023 GTS Updated Rates per February 23, 2023 Rebuttal Errata				2023 GTS Updated Rates per October 5, 2022 Rebuttal				$ Change due to February 23, 2023 Rebuttal Errata				% Change due to February 23, 2023 Rebuttal Errata			
		2023	2024	2025	2026	2023	2024	2025	2026	2023	2024	2025	2026	2023	2024	2025	2026
	Core Revenue Requirements																
1	Illustrative Backbone Transmission Base - Fixed Reservation (1)	111,126	130,979	140,801	155,682	111,126	130,926	140,689	155,280	-	53	112	402	0%	0%	0%	0%
2	Illustrative Backbone Transmission Base - Volumetric (1)	47,001	56,256	61,759	67,401	47,001	56,233	61,710	67,227	-	23	49	174	0%	0%	0%	0%
3	Subtotal Backbone Transmission Base - Illustrative (1)	158,127	187,235	202,560	223,082	158,127	187,159	202,399	222,506	-	76	161	576	0%	0%	0%	0%
4	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	-	-	-				
5	Subtotal Backbone Transmission - Illustrative (1)	158,127	187,235	202,560	223,082	158,127	187,159	202,399	222,506	-	76	161	576	0%	0%	0%	0%
6	Local Transmission Base	942,322	993,066	1,061,016	1,129,684	942,322	993,066	1,061,016	1,129,684	-	-	-	-	0%	0%	0%	0%
7	Local Transmission Adder	-	-	-	-	-	-	-	-	-	-	-	-				
8	Subtotal Local Transmission	942,322	993,066	1,061,016	1,129,684	942,322	993,066	1,061,016	1,129,684	-	-	-	-	0%	0%	0%	0%
9	Storage	22,048	35,903	37,189	42,168	22,048	35,903	37,189	42,168	-	-	-	-	0%	0%	0%	0%
10	Customer Access Charge	-	-	-	-	-	-	-	-	-	-	-	-				
11	Total Core GT&S	$1,122,497	$1,216,203	$1,300,765	$1,394,934	$1,122,497	$1,216,128	$1,300,604	$1,394,358	-	76	161	576	0%	0%	0%	0%
12	NGSS Enduser Depreciation/Decommissioning	-$71,424	$2,250	$2,250	$2,250	-$71,424	$2,250	$2,250	$2,250	-	-	-	-	0%	0%	0%	0%
13	Enduser Inventory Management	$51,030	$77,645	$80,945	$91,825	$51,808	$78,829	$82,179	$93,225	(778)	(1,184)	(1,234)	(1,400)	-2%	-2%	-2%	-2%
14	Total Core	$1,102,103	$1,296,099	$1,383,961	$1,489,010	$1,102,881	$1,297,207	$1,385,034	$1,489,834	(778)	(1,108)	(1,073)	(824)	0%	0%	0%	0%
15	Core Share of Revenue Requirement	59.8%	60.9%	60.9%	61.0%	59.9%	61.0%	60.9%	61.1%								
	Noncore / Unbundled Revenue Requirements																
16	Illustrative Backbone Trans. Base w/o G-XF Contracts (1)	226,918	243,654	261,218	276,874	226,918	243,730	261,379	277,450	-	(76)	(161)	(576)	0%	0%	0%	0%
17	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	-	-	-				
18	Subtotal Backbone Transmission - Illustrative (1)	226,918	243,654	261,218	276,874	226,918	243,730	261,379	277,450	-	(76)	(161)	(576)	0%	0%	0%	0%
19	G-XF Contracts	5,554	5,788	6,278	6,632	5,554	5,788	6,278	6,632	-	-	-	-	0%	0%	0%	0%
20	G-XF Contract Adders	-	-	-	-	-	-	-	-	-	-	-	-				
21	G-XF Contracts Subtotal	5,554	5,788	6,278	6,632	5,554	5,788	6,278	6,632	-	-	-	-	0%	0%	0%	0%
22	Subtotal Backbone Transmission - Illustrative (1)	232,472	249,442	267,496	283,506	232,472	249,518	267,657	284,082	-	(76)	(161)	(576)	0%	0%	0%	0%
23	Local Transmission Base	485,450	511,697	546,846	582,370	485,450	511,697	546,846	582,370	-	-	-	-	0%	0%	0%	0%
24	Local Transmission Adder	-	-	-	-	-	-	-	-	-	-	-	-				
25	Subtotal Local Transmission	485,450	511,697	546,846	582,370	485,450	511,697	546,846	582,370	-	-	-	-	0%	0%	0%	0%
26	Storage	-	-	-	-	-	-	-	-	-	-	-	-				
27	Customer Access Charge	3,321	4,105	4,997	5,874	3,321	4,105	4,997	5,874	-	-	-	-	0%	0%	0%	0%
28	Total Noncore / Unbundled	$721,244	$765,245	$819,340	$871,750	$721,244	$765,320	$819,501	$872,326	-	(76)	(161)	(576)	0%	0%	0%	0%
29	NGSS Enduser Depreciation/Decommissioning	($25,073)	$790	$790	$790	($25,073)	$790	$790	$790	-	-	-	-	0%	0%	0%	0%
30	Enduser Inventory Management	43,398	66,032	68,838	78,091	42,620	64,848	67,604	76,691	778	1,184	1,234	1,400	2%	2%	2%	2%
31	Total Noncore/Unbundled	$739,568	$832,066	$888,968	$950,631	$738,790	$830,958	$887,895	$949,807	778	1,108	1,073	824	0%	0%	0%	0%
32	Noncore Share of Revenue Requirement	40.2%	39.1%	39.1%	39.0%	40.1%	39.0%	39.1%	38.9%								
	Total																
33	Illustrative Backbone Transmission Base w/o G-XF Contracts (1)	385,044	430,889	463,778	499,957	385,044	430,889	463,778	499,957	-	-	-	-	0%	0%	0%	0%
34	Backbone Transmission Adders	-	-	-	-	-	-	-	-	-	-	-	-				
35	Subtotal Backbone Trans. w/o G-XF Contracts - Illustrative (1)	385,044	430,889	463,778	499,957	385,044	430,889	463,778	499,957	-	-	-	-	0%	0%	0%	0%
36	G-XF Contracts	5,554	5,788	6,278	6,632	5,554	5,788	6,278	6,632	-	-	-	-	0%	0%	0%	0%
37	G-XF Contract Adders	-	-	-	-	-	-	-	-	-	-	-	-				
38	G-XF Contracts Subtotal	5,554	5,788	6,278	6,632	5,554	5,788	6,278	6,632	-	-	-	-	0%	0%	0%	0%
39	Subtotal Backbone Transmission - Illustrative (1)	390,599	436,677	470,056	506,589	390,599	436,677	470,056	506,589	-	-	-	-	0%	0%	0%	0%
40	Local Transmission Base	1,427,773	1,504,763	1,607,862	1,712,054	1,427,773	1,504,763	1,607,862	1,712,054	-	-	-	-	0%	0%	0%	0%
41	Local Transmission Adder	-	-	-	-	-	-	-	-	-	-	-	-				
42	Subtotal Local Transmission	1,427,773	1,504,763	1,607,862	1,712,054	1,427,773	1,504,763	1,607,862	1,712,054	-	-	-	-	0%	0%	0%	0%
43	Storage	22,048	35,903	37,189	42,168	22,048	35,903	37,189	42,168	-	-	-	-	0%	0%	0%	0%
44	Customer Access Charge	3,321	4,105	4,997	5,874	3,321	4,105	4,997	5,874	-	-	-	-	0%	0%	0%	0%
45	Total GT&S	$1,843,740	$1,981,448	$2,120,105	$2,266,684	$1,843,740	$1,981,448	$2,120,105	$2,266,684	-	-	-	-	0%	0%	0%	0%
46	NGSS Enduser Depreciation/Decommissioning	(96,496)	3,040	3,040	3,040	(96,496)	3,040	3,040	3,040	-	-	-	-	0%	0%	0%	0%
47	Enduser Inventory Management	94,428	143,677	149,783	169,916	94,428	143,677	149,783	169,916	-	-	-	-	0%	0%	0%	0%
48	Total Gas Transmission and Storage System	$1,841,672	$2,128,165	$2,272,929	$2,439,641	$1,841,672	$2,128,165	$2,272,929	$2,439,641	-	-	-	-	0%	0%	0%	0%
49	Total Revenue Requirement Share	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%								

Backbone Transmission revenues are illustrative because the calculation assumes for simplicity that the core backbone capacity assignments are utilized at 100%, which is not precisely the case.

2023 Gas Transmission and Storage Cost Allocation
and Rate Design Ratecase Application
February 23, 2023 Rebuttal Errata
Attachment E Table 6-2
Illustrative End-Use Class Average Rates ($/dth) (4) (5)

Line No.		2023 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2023 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2024 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2024 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2025 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2025 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2026 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2026 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Core Retail Bundled Service (2)																
1	Residential Non-CARE	24.393	24.397	-0.005	0.0%	26.312	26.319	-0.007	0.0%	28.000	28.007	-0.007	0.0%	29.830	29.836	-0.006	0.0%
2	Residential CARE	19.244	19.248	-0.004	0.0%	20.748	20.753	-0.005	0.0%	22.070	22.076	-0.005	0.0%	23.504	23.509	-0.005	0.0%
3	Small Commercial Non-CARE	17.731	17.735	-0.005	0.0%	19.031	19.038	-0.007	0.0%	20.155	20.162	-0.007	0.0%	21.392	21.399	-0.006	0.0%
4	Small Commercial CARE	13.832	13.836	-0.004	0.0%	14.841	14.846	-0.005	0.0%	15.712	15.718	-0.005	0.0%	16.672	16.677	-0.005	0.0%
5	Large Commercial	12.928	12.893	0.036	0.3%	13.702	13.647	0.055	0.4%	14.416	14.359	0.057	0.4%	15.196	15.130	0.066	0.4%
6	Uncompressed Core NGV	12.756	12.720	0.036	0.3%	13.532	13.477	0.055	0.4%	14.253	14.195	0.057	0.4%	15.038	14.972	0.066	0.4%
7	Compressed Core NGV	27.683	27.647	0.036	0.1%	28.724	28.669	0.055	0.2%	29.365	29.307	0.057	0.2%	30.079	30.013	0.066	0.2%
	Core Retail Transport Only (3)																
8	Residential Non-CARE	19.636	19.641	-0.005	0.0%	21.358	21.365	-0.007	0.0%	22.972	22.980	-0.008	0.0%	24.688	24.697	-0.009	0.0%
9	Residential CARE	14.488	14.491	-0.004	0.0%	15.794	15.799	-0.006	0.0%	17.042	17.048	-0.006	0.0%	18.362	18.370	-0.007	0.0%
10	Small Commercial Non-CARE	13.180	13.185	-0.005	0.0%	14.309	14.316	-0.007	-0.1%	15.367	15.374	-0.008	0.0%	16.504	16.513	-0.009	-0.1%
11	Small Commercial CARE	9.282	9.286	-0.004	0.0%	10.118	10.124	-0.006	-0.1%	10.924	10.930	-0.006	-0.1%	11.783	11.791	-0.007	-0.1%
12	Large Commercial	8.756	8.720	0.036	0.4%	9.400	9.345	0.055	0.6%	10.062	10.005	0.057	0.6%	10.768	10.703	0.065	0.6%
13	Uncompressed Core NGV	8.628	8.592	0.036	0.4%	9.280	9.226	0.055	0.6%	9.951	9.894	0.057	0.6%	10.664	10.600	0.065	0.6%
14	Compressed Core NGV	23.555	23.519	0.036	0.2%	24.473	24.418	0.055	0.2%	25.063	25.006	0.057	0.2%	25.706	25.641	0.065	0.3%
	Noncore Retail Transportation Only (3)																
15	Industrial – Distribution	7.359	7.323	0.036	0.5%	7.853	7.799	0.055	0.7%	8.341	8.284	0.057	0.7%	8.847	8.782	0.065	0.7%
16	Industrial – Transmission	4.047	4.011	0.036	0.9%	4.311	4.257	0.054	1.3%	4.517	4.460	0.057	1.3%	4.729	4.665	0.064	1.4%
17	Industrial – Backbone	1.965	1.929	0.036	1.8%	2.111	2.057	0.054	2.6%	2.154	2.097	0.056	2.7%	2.210	2.146	0.064	3.0%
18	Uncompressed Noncore NGV – Distribution	7.170	7.134	0.036	0.5%	7.664	7.610	0.055	0.7%	8.152	8.095	0.057	0.7%	8.658	8.593	0.065	0.8%
19	Uncompressed Noncore NGV – Transmission	3.864	3.828	0.036	0.9%	4.119	4.064	0.054	1.3%	4.313	4.257	0.057	1.3%	4.514	4.450	0.064	1.4%
20	Electric Generation – Distribution/Transmissior	3.425	3.458	-0.033	-1.0%	3.698	3.749	-0.051	-1.4%	3.867	3.920	-0.053	-1.4%	4.056	4.116	-0.060	-1.5%
21	Electric Generation – Backbone	1.453	1.487	-0.034	-2.3%	1.615	1.666	-0.051	-3.1%	1.629	1.682	-0.053	-3.2%	1.668	1.729	-0.060	-3.5%
	Wholesale Transportation Only (3)																
22	Alpine Natural Gas	2.416	2.420	-0.004	-0.1%	2.710	2.716	-0.005	-0.2%	2.888	2.894	-0.006	-0.2%	3.090	3.096	-0.006	-0.2%
23	Coalinga	2.424	2.428	-0.004	-0.1%	2.719	2.725	-0.005	-0.2%	2.900	2.905	-0.006	-0.2%	3.103	3.110	-0.006	-0.2%
24	Island Energy	2.545	2.548	-0.004	-0.1%	2.868	2.874	-0.005	-0.2%	3.082	3.087	-0.006	-0.2%	3.318	3.324	-0.006	-0.2%
25	Palo Alto	2.384	2.387	-0.004	-0.1%	2.669	2.674	-0.005	-0.2%	2.837	2.843	-0.006	-0.2%	3.029	3.036	-0.006	-0.2%
26	West Coast Gas - Castle	6.361	6.365	-0.004	-0.1%	6.958	6.963	-0.005	-0.1%	7.508	7.513	-0.006	-0.1%	8.094	8.101	-0.006	-0.1%
27	West Coast Gas - Mather D	9.107	9.111	-0.004	0.0%	9.903	9.909	-0.005	-0.1%	10.696	10.701	-0.006	-0.1%	11.536	11.542	-0.006	-0.1%
28	West Coast Gas - Mather T	2.438	2.442	-0.004	-0.1%	2.737	2.742	-0.005	-0.2%	2.921	2.927	-0.006	-0.2%	3.129	3.135	-0.006	-0.2%

* CARE customers receive a 20 % discount on transportation and procurement and are exempt from CARE and CSI Sol

Notes:

1) Rates are based on PG&E's January 1, 2022 rate change filing per Advice Letter 4543-G as modified by the updated revenue requirement and capacity proposals in PG&E's 2023 General Rate Case, A. 21-06-021.

2) PG&E's bundled gas service is available to core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding are included in end-use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, shrinkage, transportation on Canadian and Interstate pipelines, core brokerage, and franchise fees and uncollectibles expense. The illustrative annual average rates for these elements are based on the illustrative revenue requirements shown on PG&E's Preliminary Statement Part C2. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and mandated programs and other charges.

3) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

4) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

5) Dollar difference are due to rounding.

Attachment E Table 6-3

Illustrative End-Use Noncore and Wholesale Class Average Rates with Procurement Proxy ($/dth)

Line No.		2023 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2023 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2024 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2024 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2025 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2025 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata	2026 GTS Updated Rates per February 23, 2023 Rebuttal Errata	2026 GTS Updated Rates per October 5, 2022 Rebuttal	$ Change due to February 23, 2023 Rebuttal Errata	% Change due to February 23, 2023 Rebuttal Errata
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Noncore Retail with Procurement Proxy																
1	Industrial – Distribution	11.431	11.395	0.036	0.3%	12.012	11.957	0.055	0.5%	12.546	12.489	0.057	0.5%	13.111	13.044	0.066	0.5%
2	Industrial – Transmission	8.119	8.083	0.036	0.4%	8.469	8.415	0.055	0.6%	8.722	8.665	0.057	0.7%	8.993	8.927	0.066	0.7%
3	Industrial – Backbone	6.036	6.001	0.036	0.6%	6.269	6.214	0.055	0.9%	6.359	6.302	0.057	0.9%	6.474	6.408	0.066	1.0%
4	Uncompressed Noncore NGV – Distribution	11.242	11.206	0.036	0.3%	11.823	11.768	0.055	0.5%	12.357	12.300	0.057	0.5%	12.922	12.855	0.066	0.5%
5	Uncompressed Noncore NGV – Transmission	7.936	7.900	0.036	0.5%	8.277	8.222	0.055	0.7%	8.519	8.462	0.057	0.7%	8.778	8.712	0.066	0.8%
6	Electric Generation – Distribution/Transmission	7.496	7.530	(0.033)	-0.4%	7.856	7.907	(0.051)	-0.6%	8.073	8.125	(0.052)	-0.6%	8.319	8.378	(0.058)	-0.7%
7	Electric Generation – Backbone	5.525	5.559	(0.034)	-0.6%	5.773	5.824	(0.051)	-0.9%	5.834	5.887	(0.053)	-0.9%	5.932	5.991	(0.059)	-1.0%
	Wholesale with Procurement Proxy																
8	Alpine Natural Gas	6.488	6.492	(0.004)	-0.1%	6.868	6.874	(0.005)	-0.1%	7.094	7.099	(0.005)	-0.1%	7.353	7.358	(0.005)	-0.1%
9	Coalinga	6.496	6.499	(0.004)	-0.1%	6.878	6.883	(0.005)	-0.1%	7.105	7.110	(0.005)	-0.1%	7.367	7.372	(0.005)	-0.1%
10	Island Energy	6.617	6.620	(0.004)	-0.1%	7.026	7.032	(0.005)	-0.1%	7.287	7.292	(0.005)	-0.1%	7.581	7.586	(0.005)	-0.1%
11	Palo Alto	6.455	6.459	(0.004)	-0.1%	6.827	6.832	(0.005)	-0.1%	7.043	7.048	(0.005)	-0.1%	7.293	7.298	(0.005)	-0.1%
12	West Coast Gas - Castle	10.433	10.437	(0.004)	0.0%	11.116	11.121	(0.005)	0.0%	11.713	11.718	(0.005)	0.0%	12.358	12.363	(0.005)	0.0%
13	West Coast Gas - Mather D	13.179	13.183	(0.004)	0.0%	14.061	14.066	(0.005)	0.0%	14.901	14.906	(0.005)	0.0%	15.800	15.804	(0.005)	0.0%
14	West Coast Gas - Mather T	6.510	6.514	(0.004)	-0.1%	6.895	6.900	(0.005)	-0.1%	7.127	7.132	(0.005)	-0.1%	7.392	7.397	(0.005)	-0.1%

Notes:

1) Procurement proxy based on PG&E's average core Natural Gas Vehicle (NGV) gas procurement rate which includes costs for gas commodity, gas transmission (i.e., Canadian, interstate and intrastate backbone) and shrinkage but excludes bundled storage.

2) Rates are based on PG&E's January 1, 2022 rate change filing per Advice Letter 4543-G as modified by the updated revenue requirement and capacity proposals in PG&E's 2023 General Rate Case, A. 21-06-021.

3) Rates are class average rates. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

4) Dollar difference are due to rounding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT F

INVENTORY MANAGEMENT COST ALLOCATION SCENARIOS

CALPINE WORKPAPER, TABLE 4-8 (EXCERPT)

CALPINE RESPONSE TO PG&E DATA REQUEST, SET ONE

(8/16/2022)

The following tables are extracted from Calpine Workpaper "Tables 4-8 - Revised Imbalance Forecast and IM Rates.xlsb provided in response to PG&E Data Rquest 001, dated 8/16/2022.

Intra-Day

	Sum of Absolute Value of Imbalances			
	EG	Ind	Core	Sum
2016	95	11	193	299
2017	108	13	208	329
2018	92	13	200	304
2019	113	13	204	331
2020	122	13	198	334
2021	136	13	299	448
2016-2020	**106**	**13**	**201**	**319**
Allocation	33.2%	3.9%	62.8%	100.0%
2023-2026	**69**	**13**	**188**	**270**
Revised	25.5%	5.0%	69.6%	100.0%

Inter-Day

	Absolute Value of Inter-day Imbalances			
	EG	Ind	Core	Sum
2016	78	53	46	177
2017	79	64	52	196
2018	89	50	50	189
2019	79	40	49	169
2020	83	40	47	171
2021	76	41	80	196
2016-2020	**82**	**49**	**49**	**180**
Allocation	45.3%	27.4%	27.3%	100.0%
2023-2026	**47**	**41**	**45**	**138**
Revised	33.9%	29.5%	32.5%	100.0%

Table 2B-1: Throughput Forecast Compared to 2020

	EG	Ind	Core	Subtotal	Wholesale	Total
2020	817	482	723	2,022	8	2,034
2023	450	491	712	1,653	9	1,662
2024	443	490	694	1,627	9	1,635
2025	455	489	678	1,622	9	1,632
2026	488	486	661	1,635	9	1,644
Average	**459**	**489**	**686**	**1,634**	**9**	**1,643**
vs. 2020	-44%	1%	-5%	-19%	13%	-19%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT G

EXCERPTS FROM PG&E'S 2023 GENERAL RATE CASE

EXHIBIT 3 CHAPTER 7 GAS OPERATIONS, ASSET FAMILY – STORAGE

TABLE 7-15
UPDATED PEAK DAY SUPPLY STANDARD ANALYSIS

	Demand		**2019 NGSS Design**	**Winter 2021-2022**	**Winter 2022-2023**	**Winter 2023-2024**	**Winter 2024-2025**	**Winter 2025-2026**	**Winter 2026-2027**
1	Core Demand		2493	2571	2580	2589	2600	2612	2622
2	Industrial Demand		522	565	552	556	554	553	553
3	Electric Generation		928	786	740	730	801	889	892
4	Off-System and Shrinkage		123	123	123	123	123	123	123
5	**Total Demand**	Sum Line 1-4	4066	4045	3995	3998	4078	4177	4190
	Supply								
6	Redwood Firm		1936	1957	1957	1957	1957	1819	1819
7	Northern ISPs		764	743	743	743	743	881	881
8	**Total Northern Supply**	Sum Lines 6-7	2700	2700	2700	2700	2700	2700	2700
9	Baja Firm		960	888	888	888	888	888	888
10	Gill Ranch LLC		100	100	100	100	100	100	100
11	California Production		0	35	35	35	35	35	35
12	**Total Southern Supply**	Sum Line 9-11	1060	1023	1023	1023	1023	1023	1023
13	Total Supply Without PG&E	Line 8 plus 12	3760	3723	3723	3723	3723	3723	3723
14	Withdrawal needed to meet demand only	Line 5 minus 13	306	322	272	275	355	454	467
15	Inventory Management and Reserve Capacity		550	550	550	550	550	550	550
16	Total withdrawal needed from PG&E Storage	Line 14 plus 15	856	872	822	825	905	1004	1017
17	Forecast Withdrawal Capacities at McDonald Island and PG&E Gill Ranch before any capacity investments			808	750	662	544	686	623
18	Capacity shortfall	Line 17 minus 16		-64	-72	-163	-361	-317	-394
	Capacity Investments								
19	Retaining Los Medanos			191	180	168	184	184	184
20	Cross Compression			-	94	93	94	-	67
21	Additional Wells at McDonald Island					45	45	45	45
22	Restore PG&E Gill Ranch to 100			22	30	38	46	46	46
23	**Total Capacity Additions**	Sum Lines 19-22		213	304	344	369	275	342
24	Forecast PG&E Storage capacities after investments	Sum 17 and 23		1,021	1,054	1,006	913	961	965
25	Surplus or Shortfall after Identified Investments	Line 24 minus 16		149	232	182	9	(42)	(52)

In Table 7-15, the column entitled “2019 NGSS Design” represents the forecasts that were included in the 2019 NGSS. The columns to the right of the NGSS Design column represent the peak day forecast for 1-year periods (e.g., 2021-2022, 2022-2023, etc.). Below, information included in the Table 7-15 is explained.

- Demand (lines 1-5) – PG&E has updated the demand forecasts for core, industrial, electric generation customers. The Core Demand (line 1) is the forecast demand for core customers anticipated during a 1 day in 10-year peak day event. The Industrial Demand (line 2) is the forecast for noncore industrial demand in the winter months of a 1 in 10-year cold/dry year from the California Gas Report. The Electric Generation demand forecast (line 3) reflects gas demand estimates for the minimum electric generation throughput needed to support electric reliability on a peak winter day.[45] This forecast also reflects the retirement of Diablo Canyon Power Plant in 2024 and 2025, which is expected to have a significant impact on the near-term forecast of gas demand for electric generation.[46] The Off-System and Shrinkage forecast (line 4) is firm off-system contracts under Schedule G-XF, approximately 80,000 MMcf/d and the amount of additional gas that is delivered by the customer to cover the approximately 1.3 percent shrinkage on the system. Finally, line 5 totals lines 1-4.
- Supply (lines 6-13) – PG&E has also updated its supply forecasts, dividing these forecasts between northern and southern supply.[47] For northern supply, PG&E has included updated forecasts for the Redwood transmission pipeline firm supply and Northern ISPs (lines 6-7). However, northern supply is constrained to a total of 2,700 MMcf/d. For southern supply, PG&E has included firm capacity on the Baja transmission pipeline (line 9), as well as Gill Ranch storage. In addition,

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[45] The peak winter day uses the 1-in-10 temperature of 34 degrees Fahrenheit. This event occurred on December 8, 2013. The analysis grew electric load from 2013 through 2026 using the California Energy Commission's California Energy Demand 2019-2030 forecast. See California Energy Commission, California Energy Demand 2019-2030 Managed Forecast – Mid Demand/Mid AAEE Case, Form 1.5a.

[46] To determine the electric reliability need, PG&E subtracted available in-state non-gas fired electric generation resources and estimated available power imports. The resulting gas-fired generation required to support the peak day state-wide electric demand was apportion between northern and southern California. The proportion estimate uses the NP-26 California Independent System Operator load share less gas-fired generation connected to the Kern River pipeline. Last, the estimate adds gas demand for cogeneration connected to the PG&E gas system. The cogeneration gas demand uses the average the December demands for years 2017 through 2019.

[47] Northern supply represents gas supply coming into PG&E's service territory from the northern part of its service territory while southern supply comes from the south.

the southern supply includes capacity from California in-state production (line 11). The 2019 NGSS forecast of supply resources did not include a forecast of supplies available from California production within PG&E's service area. In this updated Peak Day Supply Standard analysis, PG&E is including a forecast of 35 MMcf/d of California production which is based on the most recent 12-month history. Finally, line 13 represents the total supply without PG&E storage, which adds the total northern and southern Supplies.

- Capacity Shortfall (lines 14-18) – Line 14 shows the amount of PG&E gas storage needed to meet the peak day demand forecasts given the available supplies from the north and south. Line 15 is the withdrawal capacity for Inventory Management and Reserve Capacity. The Commission approved these amounts in the 2019 GT&S Rate Case Decision, and PG&E is not proposing to change the capacities for either service in this proceeding.[48] Line 16 is the sum of lines 14 and 15 and represents the total amount of PG&E storage withdrawal that is needed to safely operate the system. Line 17 is the forecast of withdrawal capacities from McDonald Island and PG&E's portion of Gill Ranch prior to any investments in either facility to restore capacity lost to the implementation of the safety regulations from CalGEM. Line 18 shows the shortfall of capacity compared to the PG&E withdrawal needs shown on line 16.
- Capacity Investments (lines 19-24) – This section of the analysis shows the four investments PG&E is proposing in this application to increase PG&E storage withdrawals to eliminate or substantially reduce the shortfall show on line 18. PG&E is proposing to retain the Los Medanos gas storage field (line 19) as the most cost-effective alternative to increase capacity. Additional details on the analysis to retain Los Medanos is in Section D.3 below. Line 20 is the capacity gained from the use of two compressors to compress gas produced from one well during the "clean-up" process into an adjacent well. The cross compression allows wells to be put back into service prior to

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[48] D.19-09-025, p. 24, Table 1 and pp. 34, 40.

winter operations. Without the cross compression, liquids placed into the gas wells while working on the wells to do certain inspection or to install the tubing on packers cannot "cleaned up" until there is constant withdrawal from the facility which does not normally occur until the winter months.[49] Line 21 is the capacity gained from drilling three wells at McDonald Island. PG&E had proposed in the 2019 GT&S Rate Case to drill 11 wells at McDonald Island but now would only need 3 wells with the proposed continued use of Los Medanos. Line 22 is the capacity gained by drilling new wells at Gill Ranch to restore PG&E's portion of Gill Ranch capacity to 100 MMcf/d. Line 23 is the sum of the capacity gained from the 4 investments proposed. Finally, line 24 is the total PG&E storage capacity including McDonald Island, Gill Ranch, and the four capacity investments described above.

- Capacity Surplus or Shortfall (line 25) – Line 26 shows the surplus of shortfall of capacity after the capacity investments are made compared to the PG&E storage needs shown on line 16. In the years there is a surplus, PG&E will market the capacity through its Parking and Lending tariffs and will credit back to customers all revenues received. In the years there is a shortfall, PG&E is continuing to explore several options, including rebuilding a pressure limiting station on Line 300B that is currently out of service, drilling additional wells at McDonald Island or Los Medanos, modification to several long-term off-system contracts or a combination those or other smaller projects that could yield additional capacity on a peak day for the lowest cost.

One of the primary drivers for changes between PG&E's 2019 NGSS forecast and the updated Peak Day Supply Standard analysis presented here is changes in CalGEM requirements for well reinspection intervals. At the time of the 2019 GT&S Rate Case, the reinspection interval requirements were not fully established by either PHMSA or CalGEM and it was not clear that a reinspection would need to occur within the first seven years after a well is retrofitted. In the 2019 GT&S Rate Case, PG&E

49 Exhibit (PG&E-3), WP 7-56 to WP 7-57 provides additional information on cross compression.

assumed that reinspections would not be required within the first seven years of a retrofit given this uncertainty. However, CalGEM has now indicated that reinspections may be required sooner than a risk-based frequency as described in Section B.3.a and b of this chapter. Reinspections require that a well be taken out of service and has prolonged outage impact. The level and frequency of reinspections mandated by the CalGEM regulations will require PG&E to have some wells out of service for reinspections during the peak winter months which reduces the withdrawal capacity of McDonald Island more than anticipated. Thus, additional storage capacity is needed to meet system reliability and safety needs.

3. Retention of Los Medanos

In the 2019 GT&S Rate Case, based on the 2019 NGSS Reliability Supply Standard, PG&E proposed to: (1) sell or decommission the Los Medanos and Pleasant Creek storage facilities; and (2) drill 11 new wells at McDonald Island to comply with the draft DOGGR regulations.[50] Given the updated Peak Day Supply Standard analysis in Section D.2 above, PG&E now believes the best set of investments for its customers to meet the forecasted capacity shortfall is to retain Los Medanos.[51] As the Peak Day Supply Standard analysis above demonstrates, changes have occurred since the 2019 GT&S Rate Case proceeding requiring PG&E to revise the 2019 NGSS to address capacity needs.[52] PG&E studied three alternatives to address the remaining capacity needed:

1) <u>Alternative A</u> – Drill three wells at McDonald Island; restore Gill Ranch capacity by drilling three new wells; retain the Los Medanos gas storage facilities; and install cross-compression equipment;

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50 D.19-09-025, pp. 58, 63-65.

51 In addition to retaining Los Medanos, PG&E is also proposing three additional capacity investments which are described in Section D.2 above.

52 These types of regulatory changes were expected when the Commission approved the 2019 NGSS. In the 2019 GT&S Rate Case Decision, the Commission required PG&E to submit an AL on or after December 31, 2021 “demonstrating that [PG&E] has the requisite storage capacity to operate without the Los Medanos storage field” because changes were anticipated. D.19-09-025, p. 72.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

REBUTTAL TESTIMONY OF

PETER E. KOSZALKA ON

CORE GAS SUPPLY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
REBUTTAL TESTIMONY OF
PETER E. KOSZALKA ON
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
REBUTTAL TESTIMONY OF
PETER E. KOSZALKA ON
CORE GAS SUPPLY

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Peter E. Koszalka, Director of Core Gas Supply. This testimony responds to the direct testimony of Small Business Utility Advocates (SBUA).[1] Pacific Gas and Electric Company (PG&E or the Company) summarizes parties' positions in Section B below.

Q 2 Do you have any clarifications to make to your prepared testimony?

A 2 Yes. In Chapter 7 pages 7-2 (line 4) and 7-16 (lines 13-14) the testimony states "Reduce December – February (Peak) Winter Pipeline Capacity." This should be clarified to "Reduce November – January and Increase February – March Winter Pipeline Capacity."

Q 3 Do parties criticize PG&E's showing regarding Core Gas Supply (CGS) proposals related to pipeline and storage portfolio changes, storage policy changes, and other policy changes?

A 3 Yes, SBUA criticizes CGS' proposed pipeline and storage portfolio changes on the basis that PG&E is replacing interstate pipeline capacity with natural gas storage capacity without a cost justification.[2] CGS disagrees with these criticisms and responds to each in Section C below.

Q 4 Are there proposals that parties do not dispute or do not address?

A 4 Yes, there are three proposals that parties do not dispute. These proposals are listed in Section B.

B. Summary of Parties' Positions

Q 5 Are there proposals that parties do not dispute?

A 5 Yes, parties do not dispute the following proposals that I am sponsoring:

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1 SBUA Direct Testimony.

2 *Id.* at p. 19

1. Reallocate Winter Intrastate Pipeline Capacity.[3]
2. Expanding Storage Request for Offers (RFO) Participation.[4]
3. Modify the Maximum Storage Inventory Capacity Procured via RFO.[5]

C. PG&E's Response to Parties' General Criticisms

1. PG&E's Response to SBUA's First Criticism

Q 6 What are CGS' proposed pipeline and storage portfolio and policy changes?

A 6 CGS proposed five pipeline and storage portfolio changes and one policy change. These proposed changes aim to ensure Core Procurement Entities (CGS and CTAs) can fulfill the 1-day-in-10-year reliability requirements[6]and are more fully discussed in PG&E's prepared testimony.[7]

Q 7 Does SBUA have criticisms about CGS' proposed pipeline and storage portfolio and policy changes? Please describe.

A 7 Yes, SBUA criticizes CGS' proposals for not describing likely cost implications of the changes and that CGS is proposing to replace interstate pipeline capacity with natural gas storage capacity.[8]

Q 8 Do you agree with SBUA's claim that CGS is proposing to replace interstate pipeline capacity with natural gas storage capacity?

A 8 No. SBUA mischaracterizes CGS' proposed interstate pipeline and storage portfolio changes. Although CGS is proposing to reduce interstate pipeline capacity and increase PG&E storage capacity, these proposals are not related. CGS' proposals for interstate pipeline capacity and storage capacity each satisfy independent regulatory requirements, as described below.

Q 9 Which CPUC decision requires PG&E to procure interstate pipeline capacity?

A 9 Decision (D.) 15-10-050 orders PG&E to procure interstate pipeline capacity to meet the Interstate Pipeline Capacity Planning Range requirement

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3 PG&E Errata Testimony (Aug. 18, 2022), p. 7-2, line 12 to p. 7-3, line 16.

4 *Id.* at p. 7-8, line 15, to p. 7-9, line 12.

5 *Id.* at p. 7-9, line 13 to p. 7-10, line 9.

6 D.06-07-010, pp. 36-37, Ordering Paragraph (OP) 1.

7 PG&E Errata Testimony (Aug. 18, 2022), p 7-2, line 12 to p.7-10, line 9.

8 SBUA Direct Testimony, pp. 18-19.

(Capacity Planning Range). D.15-10-050 directed PG&E to calculate the Capacity Planning Range volume from the PG&E total core load forecast in the biennial California Gas Report. The purpose of this Capacity Planning Range volume is to "have sufficient firm transportation capacity in place to meet core gas needs in PG&E's service territory."[9]

Q 10 Can gas storage capacity be used to satisfy the Capacity Planning Range requirement?

A 10 No. The Capacity Planning Range requirement defined in D.15-10-050 cannot be satisfied by gas storage capacity since gas storage does not contribute to the goal of "continuing reliability of natural gas service into California"—gas storage cannot deliver gas <u>to</u> California.[10] Gas storage is an <u>intra</u>state asset and cannot satisfy an <u>inter</u>state pipeline requirement.

Q 11 Which CPUC decisions require PG&E to procure gas storage capacity?

A 11 D.06-07-010 and D.19-09-025 order PG&E to procure gas storage capacity to meet a supply reliability standard for core customers based on a 1-day-in-10-year peak day.[11]

2. PG&E's Response to SBUA's Second Criticism

Q 12 Does SBUA have criticisms about CGS' Firm Storage proposal related to the state's climate goals? Please describe.

A 12 Yes. SBUA describes the climate goals in California Senate Bill (SB) 100 and SB 350 as admirable, and states that "PG&E has an obligation to serve existing natural gas customers, and it is currently meeting that requirement."[12] However, SBUA also reiterates its criticism that CGS is proposing to increase its use of storage and decrease its interstate pipeline capacity.

Q 13 Is the impact of CGS' interstate pipeline proposal on the state's climate goals within the scope of this application?

A 13 No. The Commission's Scoping Memo and Ruling did not include the impact of CGS' interstate pipeline proposal on the state's climate goals.

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9 D.15-10-050, p. 36, Finding of Fact 19.

10 *Id.* at p. 38, Conclusion of Law 1.

11 D.06-07-010, pp. 36-37, OP 1. D.19-09-025, p. 323, OP 19.

12 SBUA Direct Testimony, p. 20.

Q 14 Is the impact of CGS' Firm Storage proposal on state's climate goals within the scope of this application?

A 14 Yes. In the Commission's Scoping Memo and Ruling, the Commission determined issues to be considered would include "[w]hether PG&E's Core Gas Supply Firm Storage proposals are consistent with the state's climate goals, including those goals reflected in SB 100 and SB 350".[13]

Q 15 Is CGS Firm Storage proposal consistent with the state's climate goals?

A 15 Yes. CGS states that the CGS Firm Storage proposal "does not require construction of additional gas storage assets and does not conflict with the state's climate goals."[14] The state's climate goals are addressed in more detail in CGS' prepared testimony.[15]

Q 16 Do you agree with SBUA's criticism of CGS' Firm Storage proposal in relation to the state's climate goals?

A 16 No. Based on the foregoing, SBUA's criticism that CGS is replacing interstate pipeline capacity with storage is invalid. CGS explains that its Firm Storage proposal align with the state's climate goals in the prepared testimony.[16]

D. Conclusion

Q 17 What is PG&E's recommendation for Core Gas Supply's portfolio proposals?

A 17 As discussed in Section C, PG&E disagrees with SBUA's criticisms of CGS' proposals. PG&E recommends the Commission adopts CGS' proposed portfolio as written in PG&E's testimony.

Q 18 Does this conclude your rebuttal testimony?

A 18 Yes.

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13 *Assigned Commissioner's Scoping Memo and Ruling* (Jan. 5, 2022), p. 6.

14 PG&E Errata Testimony (Aug. 18, 2022), p. 7-13, lines 12-14.

15 *Id.* at p. 7-13, line 1 to p. 7-16, line 10.

16 *Ibid*.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

REBUTTAL TESTIMONY OF

STEPHEN E. SHERIDAN ON

G-NGV1 AND G-NGV4 GAS TARIFF MODIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 8
REBUTTAL TESTIMONY OF
STEPHEN E. SHERIDAN ON
G-NGV1 AND G-NGV4 GAS TARIFF MODIFICATIONS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Stephen E. Sheridan, Manager, Liquid Natural Gas/Compressed Natural Gas Engineering.

Q 2 Did any party offer written testimony relating to Chapter 8 G-NGV1 and G-NGV4 Gas Tariff Modifications of Pacific Gas and Electric Company's (PG&E) prepared testimony?

A 2 No. Parties do not offer testimony regarding PG&E's Chapter 8 G-NGV1 and G-NGV4 Gas Tariff Modifications.

Q 3 Does PG&E have any changes or corrections to its Chapter 8 proposals?

A 3 No. PG&E does not have changes or corrections to its Chapter 8 proposals.

B. Conclusion

Q 4 What is PG&E's recommendation for G-NGV1 and G-NGV4 Gas Tariff Modifications?

A 4 PG&E recommends approval of all proposals presented in Chapter 8 G-NGV1 and G-NGV4 Gas Tariff Modifications.[1]

Q 5 Does this conclude your rebuttal testimony?

A 5 Yes, it does.

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1 PG&E Errata Testimony (Aug. 18, 2022), Ch. 8.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

TODD A. PETERSON, CARL D. ORR, PATRICIA C. GIDEON, AND LUCY G. FUKUI ON THE GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM

PACIFIC GAS AND ELECTRIC COMPANY
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TODD A. PETERSON, CARL D. ORR, PATRICIA C. GIDEON, AND LUCY G. FUKUI ON THE GAS TRANSMISSION AND STORAGE REVENUE SHARING MECHANISM

A. Introduction

Q 1 What is the purpose of this Chapter 9 Rebuttal Testimony?

A 1 This testimony discusses Pacific Gas and Electric Company's (PG&E) recommendations for revisions to the Gas Transmission and Storage (GT&S) Revenue Sharing Mechanism (RSM), which PG&E recommends *only in the event* the California Public Utilities Commission (CPUC or Commission) adopts certain intervenor proposals to modify the Electric Generation (EG) rate design and/or to increase PG&E's proposed EG demand forecast. Proposals included in written testimony from three parties—The Utility Reform Network (TURN), the Northern California Generation Coalition (NCGC) and Moss Landing Power Company LLC (Moss Landing)—if adopted, may affect PG&E's recovery of its adopted noncore backbone (BB) and local transmission (LT) revenue requirements. This rebuttal testimony responds to these proposals. As discussed more fully below, PG&E's GT&S revenue requirements are allocated between core and noncore customers. The RSM tracks annual noncore (and some core) revenue over- and under-collections and distributes them between customers and PG&E's shareholders.[1]

Q 2 Please state your name and the purpose of your rebuttal testimony.

A 2 My name is Todd Peterson, Principal Strategic Analyst. My rebuttal testimony in this chapter summarizes my detailed Chapter 2A, Electric Generation Gas Demand and Throughput, rebuttal testimony regarding TURN's proposal to adjust PG&E's EG throughput forecast. I also sponsor PG&E's Chapter 5, Electric Generation Local Transmission Rate Design Analytics, rebuttal testimony regarding PG&E's study assessing whether a high fixed reservation charge and low volumetric rate benefits all EG

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[1] D.19-09-025, p. 290.

customers' gas throughput on the PG&E system. I am the sponsoring witness for Section C.1. of this rebuttal testimony.

Q 3 Please state your name and the purpose of your rebuttal testimony.

A 3 My name is Carl D. Orr, Principal Program Manager. My rebuttal testimony in this chapter quantifies the potential BB revenue requirement under-collections resulting from TURN's proposed adjustments to PG&E's EG demand forecast. I also describe the alternative BB sharing methodology that PG&E proposes for the RSM in the event the Commission adopts the intervenor proposals. In addition, I am sponsoring PG&E's, Chapter 3, Backbone Rate Inputs, rebuttal testimony. I am the sponsoring witness for Section C.2. and the co-sponsoring witness for Section C.5. of this rebuttal testimony.

Q 4 Please state your name and the purpose of your rebuttal testimony.

A 4 My name is Patricia Gideon, Principal Gas Rate Analyst. My rebuttal testimony summarizes my Chapter 6, Cost Allocation and Rate Design, rebuttal testimony responding to the direct testimony of TURN,[2] Moss Landing,[3] and NCGC[4] as it relates to the issue of an EG-LT rate design with a fixed charge component and presents my analysis quantifying potential LT revenue impacts since this noncore service is subject to the RSM. I am the sponsoring witness for Sections C.3. and C.4. of this rebuttal testimony.

Q 5 Please state your name and the purpose of your rebuttal testimony.

A 5 My name is Lucy Fukui, Principal Regulatory and Forecasting Analyst. Should the Commission adopt parties' proposals for a fixed charge EG-LT rate design component and/or increase PG&E's proposed EG load forecast, my testimony proposes modifications to PG&E's RSM to address the substantial increase in under-collection risk to PG&E's noncore BB and LT adopted revenue requirements that are currently subject to the RSM. I am the sponsoring witness for Section B.1. and the co-sponsoring witness for Section C.5. of this rebuttal testimony.

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2 TURN Prepared Testimony, Chapter 6.

3 MLPC-01, pp. 3-9.

4 NCGC-1.

B. Summary of Parties Positions and PG&E's Responses

Q 6 Please briefly summarize the parties' positions with respect to the demand forecasts and PG&E's responses.

A 6 TURN proposes to increase PG&E's forecast of EG-LT gas demand by 91 thousand dekatherms (MDth) per day and reduce PG&E's forecast of EG-BB gas demand by 32 MDth per day, if TURN's proposal in its Chapter 5 testimony for EG-LT rate design is adopted.[5] This is on top of TURN's recommendation that PG&E's forecast of market-responsive EG gas demand be increased by 16.5 MDth per day.[6] The combined impact of these proposed adjustments is an increase in EG-LT gas demand of 99 MDth per day and a decrease in EG-BB gas demand of 24 MDth per day, compared to PG&E's proposed EG forecast. Table 9-1 below summarizes TURN's recommendations.

TABLE 9-1A
TURN'S RECOMMENDED CHANGES TO PG&E'S FORECAST (MDTH/D)
MARKET RESPONSIVE ELECTRIC GENERATION GAS DEMAND
TOTAL

Line No.	Throughput (MDth/d)	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
1	PG&E Proposed (Chap 2A)	295	287	299	332
2	TURN Proposal #1	17	17	17	17
3	TURN Proposal #2	59	59	59	59
4	TURN Proposed Total	370	363	375	408

TABLE 9-1B
TURN'S RECOMMENDED CHANGES TO PG&E'S FORECAST (MDTH/D)
MARKET RESPONSIVE ELECTRIC GENERATION GAS DEMAND
LOCAL TRANSMISSION CONNECTED CUSTOMERS

Line No.	Throughput (MDth/d)	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
1	PG&E Proposed (Chap 2A)	59	56	54	55
2	TURN Proposal #1	8	8	8	8
3	TURN Proposal #2	91	91	91	91
4	TURN Proposed LT Total	159	155	153	154

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5 TURN Prepared Testimony, p. 48, lines 1-3.

6 *Id.* at p. 9, lines 11-12.

TABLE 9-1C
TURN'S RECOMMENDED CHANGES TO PG&E'S FORECAST (MDTH/D)
MARKET RESPONSIVE ELECTRIC GENERATION GAS DEMAND
BB CONNECTED CUSTOMERS

Line No.	Throughput (MDth/d)	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
1	PG&E Proposed (Chap 2A)	235	231	246	278
2	TURN Proposal #1	8	8	8	8
3	TURN Proposal #2	(32)	(32)	(32)	(32)
4	TURN Proposed BB Total	211	207	222	254

PG&E's Response: PG&E disagrees and opposes any revision to its proposed EG forecast. Moreover, PG&E's forecast uses a sound industry-endorsed PLEXOS production cost model for its forecast, which is superior to a "back-of-the-envelope" projection proposed by TURN.[7]

Q 7 Please briefly summarize the parties' positions with respect to the EG-LT rate design and PG&E's responses.

A 7 Various parties propose the following fixed charge EG-LT rate design components:

TABLE 9-2
SUMMARY OF PARTIES FIXED CHARGE EG-LT RATE DESIGN PROPOSALS

Line No.	Issue	PG&E	Moss Landing	NCGC	TURN
1	Proposals for a Fixed Charge Rate Design for EG-LT customers and Higher EG Through Put	Status quo all-volumetric rate.	Proposes a fixed monthly reservation charge and a fixed volumetric rate.	Proposes a fixed/variable rate component in opposition to an all-volumetric rate.	Proposes a fixed/variable rate design and higher EG through put.

PG&E's Response: PG&E disagrees that an EG-LT rate consisting of a full or partial fixed charge component should be a PG&E default tariff offering. PG&E proposes to continue the status quo all volumetric rate as the default tariff option.

Q 8 What is the impact of these proposals by parties on PG&E's ability to recover its adopted BB and LT revenue requirements should the Commission adopt these proposals to modify the EG-LT rate design and/or increase the EG load forecast?

7 PG&E provides a detailed response in its Chapter 2A, Electric Generation Gas Demand and Throughput (EG forecast) Rebuttal.

A 8 Incremental BB under-collection risk would increase by a total of $64 million during 2023-2026, of which 50 percent would be assigned to customers and 50 percent to PG&E under the current RSM. EG-LT under-collection risk during 2023-2026 ranges from zero, if 100 percent of EG-LT costs are collected in a fixed charge as proposed by NCGC, to upwards of $130 million if 50 percent of the EG-LT Revenue Requirement is collected in a fixed charge as proposed by Moss Landing. As the EG-LT revenue requirement collected through a fixed charge decreases, the under-collection risk increases. If 100 percent of PG&E's EG-LT revenue requirement is collected through a fixed charge, then there is no EG-LT over- or under-collection risk to PG&E's customers or shareholders if the increased throughput proposed by TURN is adopted but does not materialize.

Additionally, if TURN's proposed throughput is adopted but does not materialize, then the larger the amount of PG&E's adopted EG-LT revenue requirement designed to be collected through a variable rate, and the greater the under-collection amounts to be recovered from customers or absorbed by PG&E shareholders under the current RSM. Under the RSM, 75 percent of this risk would be assigned to customers and 25 percent to PG&E. However, if actual throughput is greater than adopted, then under the 100 percent fixed charge scenario, only the EG-LT customer class would benefit. Finally, the recommendation by NCGC and Moss Landing to provide EG-LT customers a choice between an all-volumetric rate and a rate structure consisting of a fixed component and a variable component poses additional risk of EG-LT revenue recovery due to the tendency of customers to migrate to the option that most benefits them individually as further described in Q&A 28.

1. Should the Commission Adopt Parties' Proposed Fixed Charge EG-LT Rate Design and/or Their proposed Increases In Demand, PG&E Proposes to Modify the RSM to Address the Under-Collection Risk to PG&E's Adopted Revenue Requirements (Lucy G. Fukui)

Q 9 What is the RSM and how does it work?

A 9 The RSM is defined in Gas Preliminary Statement Part CP.[8] As described there, the RSM is principally a noncore RSM, but also includes some core revenues. It tracks annual revenue over- and under-collections and shares them between customers and PG&E's shareholders to varying degrees, depending on the specific service. Currently, noncore BB and core BB usage over- and under-collections are allocated 50 percent to customers (balancing account protected) and 50 percent to shareholders. Noncore LT over- and under-collections are allocated 75 percent to customers (balancing account protected) and 25 percent to shareholders.[9]

Q 10 What are the under-collection risks PG&E forecasts could result under the RSM as it currently works should parties proposals be adopted by the Commission?

A 10 As described in Section C.2., BB under-collection risk would increase by a total of $64 million during 2023-2026, of which PG&E could recover only 50 percent through the RSM. The remaining 50 percent would fall to PG&E's shareholders. This calculation assumes that BB rates are designed based on TURN's proposed higher throughput, but actual BB throughput equals PG&E's proposed throughput.

As described in Section C.4., LT under-collection risk is dependent on the level of EG-LT revenue requirement collected in the variable portion of the rate and the differential between TURN's throughput proposal and actual throughput. The revenue risk during 2023-2026 ranges from zero, if 100 percent of the EG-LT revenue requirements is collected in a fixed charge as proposed by NCGC, to upwards of $130 million if 50 percent of the EG-LT revenue requirement is collected in a fixed charge as proposed by Moss Landing. Under the RSM, PG&E could recover 75 percent of these under-collections from customers, with the remaining 25 percent falling to PG&E's shareholders. Note that additional LT under-collection risk would arise if (as NCGC and Moss Landing propose) EG-LT customers are given a

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8 Gas Preliminary Statement Part CP, https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_PRELIM_CP.pdf (as of Sept. 28, 2022).

9 Storage revenues are excluded from the RSM because no storage costs are allocated to noncore customers.

choice between the fixed charge rate design and the current volumetric rate design. This risk, which has not been quantified, would materialize under the choice scenario due to gaming and/or displacement within the EG-LT class between those customers electing the fixed charge and those electing volumetric rates.

Q 11 How does PG&E propose to address this incremental revenue risk should the Commission adopt an increase in EG throughput and/or an optional fixed charge rate design for the EG-LT customer class?

A 11 PG&E proposes to modify the RSM to carve out the EG-LT BB and LT revenue requirements and grant them 100 percent customer sharing, or balancing account protection, (and 0 percent shareholder sharing), while leaving the existing RSM sharing percentages the same for all other noncore classes.

C. Discussion of Parties Criticisms of PG&E's Proposals and Impacts to PG&E's Ability to Recover It Adopted Revenue Requirements Under the RSM

1. TURN's Recommendation to Increase EG-LT Customers Throughput Is Not Supported (Todd A. Peterson)

Q 12 What is the EG forecast? Please describe.

A 12 PG&E's gas system transports and delivers natural gas to EG customers. PG&E designates electric generators into two groups based on the generator's responsiveness to electric market prices: non-market responsive and market responsive. The market responsive EG group consists of gas fired electric generators whose output varies in response to prices in the wholesale electricity and gas markets. The market responsive group is further divided by the level of service provided by PG&E. LT customers on PG&E's transmission or distribution systems pay different transportation charges compared to those taking service directly from the BB system. The EG forecast is discussed in detail in PG&E's prepared testimony, Chapter 2A, and its Rebuttal Testimony is presented in Chapter 2A.

Q 13 What is PG&E forecast for EG throughput?

A 13 PG&E's average-weather EG forecast is shown below from Chapter 2A of PG&E's Prepared testimony.[10]

TABLE 9-3
TABLE 2A-1 – AVERAGE-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED
(MDth/d)

TABLE 2A-1
AVERAGE-WEATHER ELECTRIC GENERATION COMPARISON TO 2020 RECORDED
(MDth/d)

Line No.		2020 Recorded	2023 Forecast	2024 Forecast[a]	2025 Forecast	2026 Forecast
1	Electric Generation					
2	Non-market-responsive EG	163	155	156	155	155
3	Market-responsive EG	654	295	287	299	332
4	*Local Transmission*	287	59	56	54	55
5	*Backbone-only*	367	235	231	246	278
6	Total Electric Generation	817	450	443	455	488

(a) Since 2024 is a leap year, calculating an annual average value from monthly data results in throughput that is slightly higher than in other years.

Q 14 What factors primarily drive the market-responsive EG forecast?

A 14 As described in PG&E's Chapter 2A prepared testimony, several factors impact market-responsive EG throughput. These factors are: (1) changes to transportation rates and forecast gas commodity prices that electric generators pay on PG&E's system relative to what other electric generators pay on other gas systems, (2) the addition of new non-gas resources (e.g., solar, wind, and battery storage), and (3) hydroelectric generation.[11]

Q 15 How do TURN's proposals impact the EG forecast?

A 15 First, TURN proposes that PG&E's forecast of market-responsive EG gas demand be increased by 16.5 MDth per day.[12] TURN proposes to split this increase in the EG forecast proportionally to the market-response EG throughput forecast: 8.25 MDth/d would be added to EG-LT (EG taking

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10 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-2, Table 2A-1.

11 PG&E Errata Testimony (Aug. 18, 2022), p. 2A-3, lines 15-20.

12 TURN Prepared Testimony, p. 9, lines 11-14.

service on the LT system) gas demand and 8.25 MDth/d to EG-BB (EG taking service on the BB system).

Second, TURN would increase PG&E's EG forecast of LT gas demand by 91 MDth per day and reduce the BB only gas demand by 32 MDth per day if TURN's proposed EG rate design is adopted.

Q 16 What is PG&E's conclusion regarding TURN's proposed adjustments to PG&E's EG forecast?

A 16 PG&E disagrees and opposes any revision to the EG forecast proposed by PG&E. TURN's proposal to adjust the EG forecast is based on a speculative assumption about the impact of its proposed EG-LT rate design. In contrast, PG&E's forecast uses a sound industry-endorsed PLEXOS production cost model for its forecast, which is superior to a "back-of-the-envelope" projection proposed by TURN.

Q 17 What changes to the EG-LT and EG-BB demand forecasts for the years 2023-2026 does TURN propose?

A 17 A comparison of PG&E's proposed EG-LT and EG-BB and TURN's proposed adjustments to both with resulting percentage changes are presented below and reflect significant throughput increases.

TABLE 9-4
CHANGE IN EG DEMAND FORECASTS UNDER TURN'S PROPOSAL

Line No.	Volumes (MDth/d)	2023	2024	2025	2026
1	PG&E Propose EG LT	59	56	54	55
2	PG&E Propose EG BB	235	231	246	278
3	PG&E EG Volumes paying BB Transmission under GT&S RSM	295	287	299	332
4	EG LT with TURN Proposed Increase under Fixed Charge EG LT Rate Design	99	99	99	99
5	EG BB with TURN Proposed Increase under Fixed Charge EG LT Rate Design	(24)	(24)	(24)	(24)
6	TURN EG Volumes Paying Unbundled BB Transmission Rates under GT&S RSM	370	363	375	408
7	Change in TURN vs PG&E EG Volumes Paying LT Function	167%	177%	185%	182%
8	Change in TURN vs PG&E EG Volumes Unbundled BB Transmission Rates	26%	26%	25%	23%

2. TURN's Proposed Adjustments to PG&E's EG Demand Forecast Would Increase PG&E's Risk of Under-Collecting Its Noncore BB Revenue Requirement (Carl D. Orr)

Q 18 How would TURN's proposed adjustments to PG&E's EG demand forecast impact PG&E's ability to recover its adopted noncore BB revenue requirements?

A 18 TURN's EG demand forecast would increase PG&E's risk of under-collecting its BB revenue requirement by $64 million during 2023-2026, of which PG&E could recover 50 percent through the current RSM. The remaining 50 percent would fall to shareholders. This calculation assumes that BB rates are designed based on TURN's proposed higher throughput, but actual BB throughput equals PG&E's proposed throughput.[13]

3. PG&E's Response to Parties' Criticisms Regarding the Design of Market Responsive EG-LT Rates (Patricia C. Gideon)

Q 19 What is PG&E's proposal regarding EG-LT rate design?

A 19 PG&E proposes to continue a single average volumetric LT rate for all noncore and wholesale customer classes. PG&E's proposal is more fully discussed in PG&E's prepared testimony.[14]

PG&E's conclusion to maintain its status quo EG-LT rate design is based on its analysis of how a new Gas EG-LT rate design could impact net EG gas throughput compared to the status quo rate design.[15] The full analysis is presented in Chapter 5 of PG&E's prepared testimony. The rate design analyzed was comprised of a high fixed reservation charge and a low volumetric rate. The analysis showed conflicting results whether a rate design with the described reservation and volumetric components increased total EG customers' gas throughput on the PG&E system.[16] The analytical results did not provide conclusive results.[17]

Q 20 Do parties have criticisms of PG&E's conclusion to maintain the currently adopted market responsive EG-LT rate design based on the analysis detailed by PG&E in Chapter 5 of its prepared testimony?

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13 PG&E has not quantified the BB revenue risk associated with the NCGC and Moss Landing EG-LT rate design proposals because of the unknown impact on throughput.

14 PG&E Errata Testimony (Aug. 18, 2022), p. 6-12, lines 2-14.

15 PG&E Errata Testimony (Aug. 18, 2022), p. 5-1, lines 6-12.

16 *Id.* at lines 19-23.

17 *Id.* at p. 5-13, lines 13-16.

A 20 Yes, as detailed in my Chapter 6 rebuttal testimony, Moss Landing, NCGC and TURN take issue with PG&E's decision to not propose an alternate EG-LT rate with a fixed charge component.

Q 21 Please summarize parties' alternate recommendation to PG&E's volumetric EG-LT rate.

A 21 The following are parties' recommendations:

- Moss Landing recommends that:

  > The Commission should continue to allow EG-LT customers to choose a rate structure that combines a fixed reservation charge with a volumetric rate … and should also authorize a variation of this rate structure that fixes the volumetric rate for the period covered by this rate case, or at least for each year of the rate case period.[18]

- NCGC proposes a rate design that allows customers:

  > [T]he option of remaining either on the all-volumetric rate proposed by PG&E, assuming it is approved by the Commission, or to convert a portion of the customer's specific LT related revenue requirement to a fixed payment.[19]

  > NCGC proposes that 100 percent of the LT and NCA-LT[20]

  Subaccount be collected in a fixed rate component.

- TURN proposes that the Commission:

  > Adopt a fixed/variable rate design as the standard for the entire EG-LT customer group, using the same general methodology employed by PG&E when it provided such rates to a subset of EG-LT customers on a negotiated basis only.[21]

Q 22 How does PG&E respond to these recommendations in general?

A 22 For the reasons discussed in Chapter 6 of my rebuttal testimony, as well as the additional considerations discussed in this Chapter 9, PG&E disagrees that an EG-LT rate consisting of a fixed charge rate component, either as the only EG-LT rate structure or as an alternative option to the status quo all variable rate structure, should be part of a tariff offering. PG&E proposes to continue the currently adopted all volumetric rate design.

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[18] MLPC-01, p. 3.

[19] NCGC-1, p. 13, lines 24-27.

[20] Noncore Customer Class Charge Account, LT Subaccount.

[21] TURN Prepared Testimony, p. 2, lines 24-27.

Q 23 Please describe these additional considerations.

A 23 Under a fixed charge design, there are other considerations in terms of revenue risk for other customer classes. As discussed in Chapters 2A and 5 of PG&E's Errata Testimony,[22] there are other factors outside of PG&E's control that drive demand for electricity from EG-LT power plants and resulting potential revenues. For example, these factors include the:

- Drought situation and resulting available hydroelectric generation;
- Actual Cooling Degree Days and Heating Degree Days experienced in summer and winter, respectively, and demand for electricity overall;
- Availability of other resources bidding into California Independent System Operator; and
- Differential between the Northern and Southern California gas marketplace in the comparative commodity rate outside of the rate design recovery of PG&E's LT component.

Q 24 What are the implications of these additional considerations?

A 24 To the extent that these transitory and unforecastable elements described above dominate the demand for EG-LT throughput over the course of the 2023-2026 rate case period, under a fixed charge rate structure, power plants could experience benefits due to a lower variable rate and other customer classes would benefit less due to lower variable rate if demand of EG-LT customers is more than the forecast used for rate design.

What cannot be forecasted over the four-year rate case period is how other drivers, beyond the rate design, could compound to result in actual EG-LT throughput that is significantly different than adopted. Under an all-volumetric rate, a substantial increase in actual EG-LT throughput during a rate case period relative to adopted throughput would result in substantial sharing of those additional revenues above adopted revenue requirements with other LT customer classes under the RSM. However, under a substantially fixed charge rate design for recovery of the EG-LT component and a lower volumetric rate, the result is a more limited collection of revenue. Compared to the current all-volumetric rate design, this limited collection of revenue from the EG-LT class would be at the expense of other

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[22] PG&E Errata Testimony (Aug. 18, 2022).

customer classes and PG&E shareholders who, under the RSM, would no longer benefit from the increased throughput and additional revenues because of the fixed charge component. PG&E supports an all-volumetric rate that shares both the upside and downside of revenue collection among all customer classes, and due to the RSM with PG&E shareholders.

Q 25 Are there circumstances where PG&E would be willing to consider a rate design that includes a fixed charge, instead of an all-volumetric rate for the EG-LT customer class?

A 25 Not in this case but perhaps in a future case.

First, PG&E opposes the rate design proposals of Moss Landing and NCGC, which significantly increase the exposure to non-recovery of a portion of the revenue requirements approved for LT and BB transmission.

Second, PG&E strongly opposes making a fixed charge rate an optional alternative to the existing all-volumetric rate due to the self-selection effect identified by TURN in A. 28, below, as well as PG&E. This opposition applies to all three intervenors' fixed rate proposals in the testimony of Moss Landing, NCGC, and TURN.

Third, PG&E opposes TURN's fixed charge rate proposal since TURN has coupled it with a change in EG-LT class throughput, which PG&E opposes.

If a fixed charge rate proposal were to be considered without any change to demand, PG&E would be willing to consider that fixed charge rate proposal as a mandatory rate, in the future, although the results of the study in Chapter 5 about fixed charge rates was inconclusive. In that event, PG&E would still strongly recommend adoption of the modifications to the RSM presented in this rebuttal testimony, which would give ratepayers upside benefit if actual demand were to be higher than forecast, as TURN apparently believes.

To sum, PG&E is opposed to any intervenor fixed charge proposal in this proceeding but would consider a fixed charge in the future with sufficient analysis of support.

4. Parties Adjustments to PG&E's Proposed EG Throughput and EG-LT Fixed Charge Rate Design Impacts PG&E's Risk of Under-Collecting Its Adopted LT Revenue Requirements (Patricia C. Gideon)

Q 26 Should the Commission adopt TURN's adjustments to the EG class throughput forecast based on TURN's proposed EG-LT power plant fixed charge rate design, what are the estimated impacts to the LT rate and the amount at risk under the RSM?

A 26 Even if a predominantly fixed charge design is made the standard tariff for all EG-LT power plants under the G-EG tariff, there remains a question of volumetric revenue recovery under TURN's proposed increase in net EG customer class throughput. Table 9-5 summarizes the potential risk of under-collection of PG&E's adopted EG-LT revenue requirement based on the recommendations by TURN, NCGC and Moss Landing. Note that the table below assumes that the actual volumes are equal to PG&E's forecasted throughput rather than the adjusted throughput as proposed by TURN; however, the fixed charge and variable rates are set on TURN's proposed adjusted volumes, since the analysis assumes that TURN's volumes would be adopted and would be the throughput forecast on which rates are designed. This analysis also assumes that the fixed charge EG-LT rate design is made the standard tariff rather than being an option to the status quo EG-LT all-variable rate design as proposed by NCGC and Moss Landing.

TABLE 9-5
OVER/(UNDER)COLLECTION DUE TO EG-LT FIXED CHARGE RATE DESIGN AND TURN'S INCREASED EG THROUGHPUT
(THOUSANDS OF DOLLARS)

Line No.	Fixed/Variable Rate Design Proposal	Total Estimated Over/(Under) Collection 2023-2026	75 percent Customer Sharing Under Current RSM	25 percent Shareholder Sharing Under Current RSM
1	NCGC: 100 percent Fixed Charge	–	–	–
2	TURN: $0.0500/dth Variable Rate with the remaining LT Revenue Requirement collected in a Fixed Charge	$(7,250)	$(5,437)	$(1,812)
3	Moss Landing: 50 percent Fixed, 50 percent Variable	$(131,972)	$(98,979)	$(32,993)

Q 27 Does additional LT under-collection risk exist should the Commission adopt an EG-LT fixed charge rate design that allows customers to choose between it and the status quo all volumetric rate design?

A 27 Yes, there is additional risk of PG&E under-collecting its adopted LT revenue requirement allocated to the EG-LT power plant class not included in the analysis described above.

Q 28 Please describe.

A 28 NCGC and Moss Landing propose to allow each EG-LT power plant customer to choose between a volumetric or fixed charge rate design collection of its LT revenue requirement allocation/responsibility. These proposals could add additional risk of LT under-collections, in addition to TURN's proposal since some power plants could sign up for the fixed charge while other power plants, potentially with the same ownership or with the similar contractual relationships for their electricity output, remain on the all-volumetric rate design. Whether by design or random impact, under such outcomes of differential throughput by power plant, the total EG-LT throughput could increase but still result in PG&E under-collecting its adopted LT revenue requirements if EG generation moves to plants with the fixed charges based on its historic share of usage while other plants generate very marginally.

TURN, in its opening testimony recognizes the risk under the choice scenario as follows:

> Also, providing customers within the same class with more than one rate option can be problematic, as customers will tend to migrate to the option that most benefits them individually, which can often result in a revenue shortfall for the class overall, a process known as "adverse selection."[23]

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23 TURN Opening Testimony, p. 36, lines 3-6.

5. PG&E Proposes to Modify the RSM to Carve Out EG-LT Revenue Requirements and Grant Them 100 percent Customer Sharing (and 0 percent Shareholder Sharing), While Leaving the Existing RSM Sharing percentages the Same for All Other Noncore Classes (Lucy G. Fukui and Carl D. Orr)

Q 29 How does PG&E propose to modify the RSM to address the incremental risk of PG&E under-collecting its authorized BB and LT revenue requirements?

A 29 PG&E proposes to modify the RSM to address the increased risk of under-collecting its adopted BB and LT revenue requirements associated with EG customers on the LT system. Should the Commission adopt some or all of the proposals from TURN, NCGC, or Moss Landing to adopt an EG-LT fixed rate design and/or revise PG&E's EG throughput forecast, then PG&E recommends revising the RSM under the following circumstances:

TABLE 9-6
COMBINATION OF INTERVENOR'S THROUGHPUT AND FIXED CHARGE RATE DESIGN FOR EG-LT CUSTOMER CLASS UNDER WHICH PG&E PROPOSES MODIFYING THE RSM

Line No.	Fixed Charge Adopted	Fixed Charge Mandatory[(a)] or Choice	TURN's Higher Throughput Adopted Rather Than PG&E's Proposed Throughput Forecast	PG&E's RSM Proposal
1	No	N/A	No	No change to RSM
2	Yes	Mandatory	No	No change to RSM
3	Yes	Mandatory	Yes	Modify RSM to address increased risk from EG-LT Class
4	Yes	Choice	No	Modify RSM to address increased risk from EG-LT Class
5	Yes	Choice	Yes	Modify RSM to address increased risk from EG-LT Class

(a) PG&E proposes the fixed charge be mandatory with no customer choice if the CPUC adopts a fixed charge.

Q 30 How does PG&E propose to modify the RSM?

A 30 PG&E proposes to carve out the EG-LT revenue requirements and grant them 100 percent customer sharing, or 100 percent balancing account protection (and 0 percent shareholder sharing), while leaving the existing RSM sharing percentages the same for all other noncore classes.

Q 31 What specific modifications to the RSM does PG&E propose in order to carve out the EG-LT revenues to implement 100 percent customer sharing?

A 31 PG&E proposes the following modifications to the RSM if the conditions are met in Table 9-6, lines 3-5:

- <u>For LT revenue sharing</u> – PG&E proposes to remove the EG-LT customer class from the LT subaccount of the RSM and establish a new EG-LT subaccount through which 100 percent of the EG-LT revenue requirements and associated revenues are tracked and recorded. Alternatively, PG&E proposes to move recovery of its EG-LT revenue requirement to another balancing account where other noncore revenues are 100 percent balancing account protected.
- <u>For BB revenue sharing</u> – PG&E's BB rates do not have an EG-LT class that allows for identification of the EG-LT BB revenue requirement or the EG-LT BB revenues. Therefore, PG&E proposes to create a proxy EG-LT BB revenue requirement by multiplying the *adopted* EG-LT demand by the average noncore BB rate. Similarly, PG&E proposes to create proxy EG-LT BB revenues by multiplying *recorded* EG-LT demand by the average noncore BB rate. Then, PG&E proposes to remove the EG-LT customer class from the BB subaccount of the RSM and establish a new EG-LT BB subaccount through which 100 percent of the proxy EG-LT BB revenue requirements and associated proxy revenues are recorded and tracked. Alternatively, PG&E proposes to move recovery of its EG LT revenue requirement to another balancing account where other noncore revenues are 100 percent balancing account protected.

Q 32 Please provide an illustration of the modified BB RSM PG&E proposes.

A 32 The requested illustration is provided in the table below.

TABLE 9-7
ILLUSTRATIVE 2023 BB REVENUE SHARING WITH 100 PERCENT CUSTOMER SHARING FOR EG-LT CLASS AND 50 PERCENT CUSTOMER SHARING FOR ALL OTHER CLASSES

	Total	EG-LT Proxy	Remainder
2023 Revenue Requirement ($ million)			
Backbone Total	$400		
Less Core Reservation	($104)		
Less Schedule G-XF	($6)		
Net - Subject to RSM	$290	$33 (a)	$257
2023 Illustrative Revenues ($ million)			
Backbone Total	$370		
Less Core Reservation	($104)		
Less Schedule G-XF	($6)		
Net - Subject to RSM	$260	$12 (b)	$248
Over / (Under) Collection ($ million)	($30)	($20)	($9)
Sharing Percentages			
Customer		100%	50%
Shareholder		0%	50%
Sharing Results ($ million)			
Customer	($25)	($20)	($5)
Shareholder	($5)	$0	($5)

Notes
(a) Based on average noncore backbone rate of $0.560/Dth and adopted EG-LT demand of 159 MDth/d.
(b) Based on average noncore backbone rate of $0.560/Dth and recorded EG-LT demand of 60 MDth/d.

D. Conclusion

Q 33 What is PG&E's recommendation for EG forecast?

A 33 PG&E recommends the adoption of the EG forecast as presented in Chapter 2A. As discussed in Section C.1, PG&E disagrees with TURN's substantial increase to PG&E's EG forecast. PG&E's EG forecast represents the best gas throughput electric generation forecast using the industry's preferred model PLEXOS. Additionally, the EG forecast uses State's policy regarding EG resources found in the CPUC's IRP PSP adopted by the Commission.

Q 34 What is PG&E's recommendation for a fixed charge EG-LT component?

A 34 PG&E recommends continuing a single average volumetric LT rate for all noncore customer classes. As discussed in Section C.3, PG&E's conclusion to maintain its status quo EG-LT rate design is based on its analysis of how a new EG-LT rate design could impact net EG gas throughput compared to the status quo rate design.[24] The rate design analyzed was comprised of a high fixed reservation charge and a low volumetric rate. The analysis showed conflicting results whether a rate design with the described reservations and volumetric components benefitted all EG customers gas throughput on the PG&E system.[25] The analytical results did not provide conclusive results.

PG&E recommends that the Commission reject the proposals of Moss Landing, NCGC and TURN in their testimonies. However, a fixed charge rate design may be worth considering in the future.

Q 35 What is PG&E's recommendation to address the substantial increasing under-collection risk to PG&E's adopted BB and LT functions if the Commission adopts intervenors' throughput and fixed charge EG-LT rate design?

A 35 If the Commission adopts intervenors' proposals discussed in this chapter, PG&E proposes to modify the RSM to carve out the EG-LT classes assigned LT and BB revenue requirements and grant them 100 percent customer sharing (and 0 percent shareholder sharing) while leaving the existing RSM sharing percentages the same for all other noncore classes.

Q 36 Does this conclude your rebuttal testimony?

A 36 Yes, it does.

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24 PG&E Errata Testimony (Aug. 18, 2022), p. 5-1, lines 6-12.

25 *Id.* at lines 19-23.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAMES CHEN

Q 1 Please state your name and business address.

A 1 My name is James Chen, and my business address is Pacific Gas and Electric Company, 6121 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am an Expert Gas Transmission Product Manager in PG&E's Wholesale Marketing and Business Development Department. I am responsible for managing the market storage and transportation program. This includes managing customer portfolios in conjunction with maintenance and outages on our backbone system to ensure adequate capacity to meet market and service obligations while maintaining system reliability.

In addition, I helped develop PG&E's Natural Gas Storage Strategy as presented in PG&E's 2019 Gas Transmission and Storage Rate case. In PG&E's 2023 General Rate Case, I am also the witness assistant for Roger Graham, a witness for Gas System Operations. I was involved in developing the analysis, testimony, and workpapers for PG&E's Gas System Operations proposals in Chapter 7.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science Degree in Economics and Business Administration from Saint Mary's College of California in 2008. Prior to graduation, I worked as an intern at Chevron from 2006 to 2008. After graduation, I started as an analyst at Commercial Energy of Montana in 2008. My roles included creating and maintaining various sales, risk, and financial reporting models to expand the Core Transport Agent, Energy Efficiency, and Renewable lines of business. I departed Commercial Energy of Montana in 2013 as a risk manager and started my role as Senior Gas Transmission Product Manager here at PG&E.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023 GT&S Cost Allocation and Rate Design Proceedings:

- Chapter 4, "Local Transmission Cost Allocation Study";

- Sections B and C; as expressly noted therein; and
- Chapter 6, "Cost Allocation and Rate Design";
  - Q 71 and Q.72.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LUCY G. FUKUI

Q 1 Please state your name and business address.

A 1 My name is Lucy G. Fukui, and am currently working remotely as Pacific Gas and Electric Company (PG&E) transitions from its prior location at 77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Analyst on the Regulatory Analysis and Forecasting team in the Energy Accounting Department within the Corporate Accounting organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery issues. In this position, a primary responsibility includes providing testimony as an expert witness on cost recovery issues related to balancing accounts.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration, emphasis in Accounting, with a minor in Computer Science, from the University of San Francisco. I earned a Certified Public Accountant certificate in the state of California in 1990.

Prior to joining PG&E in 1991, I was an Auditor with Deloitte and Touche and an Accounting Manager for a small software company. I have over 25 years of regulated utility accounting and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations. I have also sponsored testimony regarding balancing accounts and cost recovery in numerous proceedings at the California Public Utilities Commission.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2023 GT&S Cost Allocation and Rate Design Proceedings:

- Chapter 9, "Gas Transmission and Storage Revenue Sharing Mechanism":
  - Sections A1 and C.5.

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

ACRONYMS AND ABBREVIATIONS

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX B
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

Acronym	Definition
#	
$/Dth	dollars per dekatherm
A	
aMW	average megawatts
APD	Abnormal Peak Day
Atch	attachment
B	
BB	backbone
Bcf	billion cubic feet
C	
C&T	Citadel Energy Marketing LLC and Tourmaline Oil Marketing Corp
CAC	Customer Access Charges
CAISO	California Independent System Operator
Calpine	Calpine Corporation
CARD	Cost Allocation and Rate Design
CDD	Cooling Degree Days
CEC	California Energy Commission
CFCA	Core Fixed Cost Account
CGS	Core Gas Supply
COL	Conclusion of Law
COVID-19	coronavirus disease 19
CPUC	California Public Utilities Commission or Commission
CYPM	Cold Year Peak Month
D	
D.	Decision
Dth	dekatherm
E	
EG	Electric Generation
EG forecast	Electric Generation Gas Demand and Throughput
EG-D/T/BB	Electric Generation Distribution Transmission Backbone
EG-LT	Electric Generation Local Transmission
EIA	Eenrgy Information Administration
F	
fn	footnote
FOF	Finding of Fact
G	
G-AA	As Available Transportation On-System
G-AAOFF	As-Available Transportation Off-System
G-AFT	Annual Firm Transportation On-System
G-AFT	Annual Firm Transportation On-System
G-AFTOFF	Annual Firm Transportation Off-System
GCAP	Gas Cost Allocation Proceeding
G-EG-BB	Gas Transportation Service to Electric Generation Backbone
GHG	greenhouse gas
G-LEND	Market Center Lending Services
G-NAA	Negotiated As-Available Transportation On-System
G-NAAOFF	Negotiated As-Available Transportation Off-System
G-NFT	Negotiated Firm Transportation On-System
G-NFTOFF	Negotiated Firm Transportation Off-System
G-NGV1	Core Natural Gas Service for Compression on Customers' Premises
G-NGV4	Noncore Natural Gas Service for Compression on Customers' Premises
G-NR2	Gas Service to Large Commercial Customers
G-NT-BB	Gas Transportation Service to Noncore End-Use Customers
G-NTD	Gas Transportation Service to Noncore End-Use Customers Distribution
G-PARK	Market Center Parking Services
GRC	General Rate Case
G-SFT	Seasonal Firm Transportation On-System Only

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX B
GLOSSARY OF ACRONYMS AND ABBREVIATIONS
(CONTINUED)

Acronym	Definition
GT&S	Gas Transmission and Storage
GWh	gigawatt hours
G-WSL	Gas Transportation Service to Wholesale/Resale Customers
G-XF	Pipeline Expansion Firm Intrastate Transportation Service
H	
HDD	heating degree days
I	
IRP	Integrated Resource Planning
IS	Indicated Shippers
ISO	Independent Storage Provider
ISP	Independent Storage Provider
J	
K	
L	
LT	Local Transmission
M	
MDth	thousand dekatherms
MDth/d	thousands of dekatherms per day
MMcf	million cubic feet
MMcf/d	millions of cubic feet per day
MMT	million metric ton
Moss Landing	Moss Landing Power Plant Company LLC
Mth	thousand therms
Mth/d	thousand therms per day
MW	megawatts
N	
NAIC	North American Industry Classification System
NCA	Noncore Customer Class Charge Account
NCA-LT	Noncore Customer Class Charge Account Local Transmission
NCGC	Northern California Generation Coalition
NGSS	Natural Gas Storage Strategy
NGV	natural gas vehicle
O	
OIR	Order Instituting Rulemaking
OP	Ordering Paragraph
P	
PG&E	Pacific Gas and Electric Company
PSP	Preferred System Plan
Q	
R	
RFO	Request for Offers
RNG	renewable natural gas
RRQ	revenue requirement
RSM	Revenue Sharing Mechanism
S	
SB	Senate Bill
SBUA	Small Business Utility Advocates
SCADA	Supervisory Control and Data Acquisition
SFV	Straight Fixed Variable
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
T	
T/BB	Transmission Backbone
TURN	The Utility Reform Network
U	
U.S.	United States

Acronym	Definition
V	
W	
WECC	Western Electricity Coordinating Council
X	
Y	
Z	